



European  
Commission

# Quarterly Report

## on European Electricity Markets

with focus on the impact of high  
commodity prices and recovery  
demand in the electricity sector

Market Observatory for Energy

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## HIGHLIGHTS OF THE REPORT

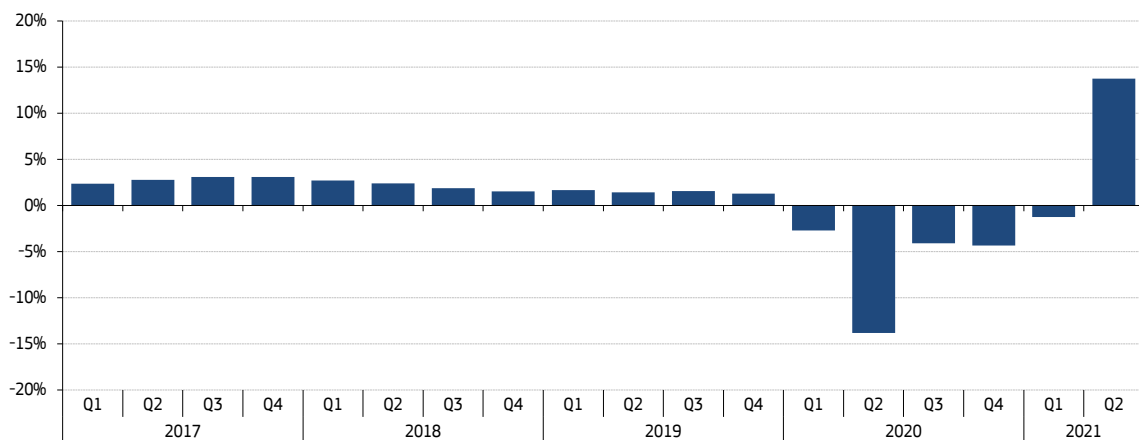
- **The second quarter of 2021 brought electricity consumption in Europe very close to pre-pandemic levels**, driven by an increase of economic and social activity, as COVID lockdown measures eased in most parts of Europe. **EU-wide consumption increased by 11% year-on-year in Q2 2021**, thanks to recovering industrial and labour activity. Heating and cooling demand also influenced the rise in demand during the quarter. Nonetheless, power demand was still slightly below 2019 levels (-0.5%).
- **Markets in the region saw a sharp increase on wholesale electricity prices compared to Q2 2020.** A steep rise in commodity prices (mainly gas, coal, and to a lower extent CO<sub>2</sub>) combined with increased power demand linked to the economic recovery and temperature fluctuations in Europe drove prices to 13-year highs in many European markets. Prices continued the rally during the following months, reaching historical records in September. The European Power Benchmark averaged 68 €/MWh in Q2 2021, 158% higher on yearly basis. Compared to Q2 2019, the quarterly average price rose by 58%.
- Economic recovery, a colder-than-average spring and heatwaves in June pushed up electricity demand and made more space for fossil fuels in the electricity mix, in spite of increasing carbon prices. However, the **share of renewables still managed to reach 42%, beating fossil fuels (32%)**. The presence of renewables in the mix was supported by an increase of 11% in solar generation (+6 TWh), 7% of wind (+5 TWh) and 7% biomass (+2 TWh) on a yearly basis. Low levels of electricity demand during the first lockdown of 2020, amplified the comparative increase in fossil fuel generation during the quarter. Coal and lignite generation rose by 29% (+17 TWh). High gas prices reversed coal-to-gas switching in most markets during the reference quarter. Despite increasing prices, gas-fired generation saw its output grow by 9% (+10 TWh), while nuclear output registered an increase of 11% (+16 TWh).
- Based on preliminary estimates, **the carbon footprint of the EU power sector rose by 19% in Q2 2021 compared to Q2 2020, but it was still 10% lower than in Q2 2019.** Despite high carbon prices, carbon emissions could still rise this year due to high commodity prices, especially gas, which have a detrimental effect on coal-to-gas switching. More extreme temperatures, colder winter spells and higher summer temperatures combined with the strength of the post-pandemic recovery, offset the higher carbon price.
- **Energy prices have been rising to all-time highs, triggering considerable political and social concerns in an increasing number of Member States.** Wholesale electricity prices have surged 180% year-on-year in August and registered a fivefold increase since the lowest recorded prices in the pandemic. Most Member States experienced yearly increases above 100% and some of them, close to or even over 200%. More expensive electricity can be explained by a global rise in natural gas prices and, to a lower extent, strengthening carbon prices. Increased energy demand coming along with the post-Covid economic recovery has also played its part in driving power prices higher. The European Commission recently worked on a toolbox for actions, both short and medium-term, that Member States can implement to deal with this temporary surge in electricity prices, underlying that the delivery of the European Green Deal is fundamental.
- **Factors such as high gas prices or a steep increase in demand can overcome the effect of carbon prices in driving the energy transition.** Rising gas prices have led to a worsening of gas-fired power plants' margins, in spite of record-high carbon prices, as could be observed so far in 2021. This situation has negated incentives for coal-to-gas switching. Lignite-fired generation, with negligible fuel cost but higher level of emissions, managed to gain share in many European power mixes to the detriment of gas.
- **An increased share of renewables in the system**, combined with other low carbon sources with low marginal costs and higher energy efficiency efforts, **would make fossil fuels less significant in setting wholesale market prices.** Enhanced interconnection between Member States will lead to greater price convergence and lower prices. Improved efforts to achieve greater energy efficiency will lower demand requirements for the grid and also contribute to lower prices. Flexible demand, combined with the deployment of smart meters and smart grids will allow softening times of peak demand through demand response measures. Overall, a well-functioning and well-integrated EU energy market, continued investment in renewable technology and improvements in energy efficiency are key to keep prices in check for all consumers. This is the core of the Fit for 55 climate and energy package.
- Demand for electrically chargeable vehicles (ECVs) rose over Q2 2021 on yearly basis. Member States kept support policies aimed at incentivising purchases and the phase-out of new combustion engine cars in many Member States by 2030. As a result, **almost 450,000 new ECVs were registered in the EU in the second quarter of 2021 (+245% year-on-year)**. This was the second-highest quarterly figure on record (close to Q4 2020 levels) and translated into an impressive 16% market share, one and a quarter times compared to China and almost five times higher than in the United States.

# 1 Electricity market fundamentals

## 1.1 Demand side factors

- **Figure 1** shows in Q2 2021 a strong economic recovery from the pandemic shock which swept across Europe during 2020 and 2021, fostering a recovery from the previous months. The lift on restrictions on economic and social activity and the massive roll out of vaccination, had a palpable impact on the daily lives of millions of citizens and operations of the majority of business. According to an estimate published by Eurostat in September 2021, seasonally adjusted GDP in the EU increased by 13.8% year-on-year between April and June 2021. This was by far the sharpest increase since the time series began in 1995 and demonstrates in the first place the scale of economic and social disruption brought by the pandemic, and the following scale of the economic recovery. This is the first quarter with positive growth since five consecutive negative growth quarters following the start of the pandemic. A rise in output was observed in every Member State. The highest increases were reported in Ireland (+21.1%), Spain (+19.8%), France (+18.7%), Hungary (17.7%) and Italy (+17.3%).

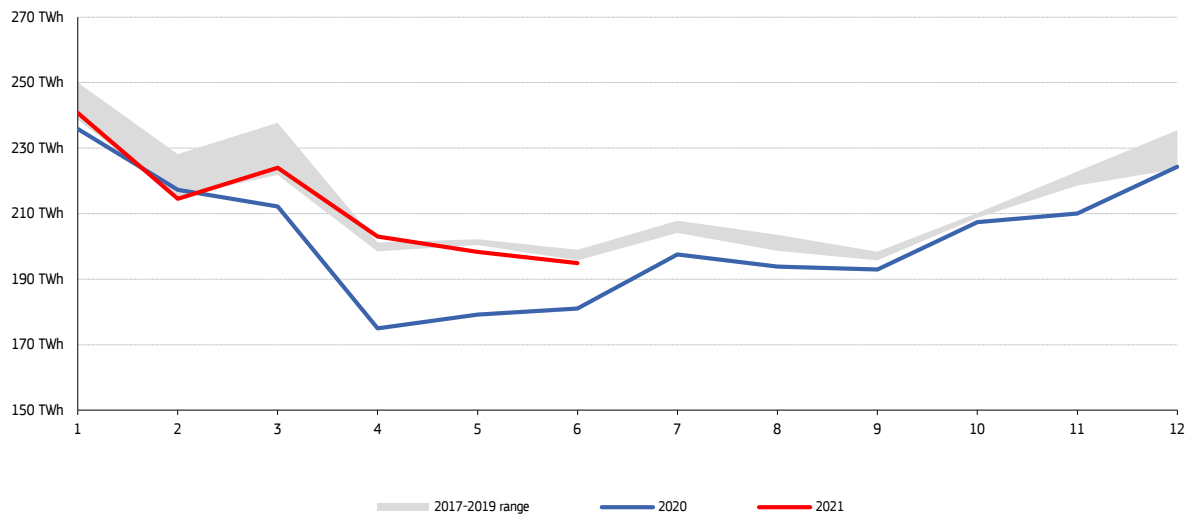
**Figure 1 – EU GDP annual change (%)**



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU rose 11% above last year's levels in Q2 2021, driven by a strong resurgence of economic and social activity. Demand has almost returned to pre-pandemic levels, being slightly over the historical range during April and slightly below the average on May and June. Nonetheless, power demand is still slightly below 2019 levels (-0.5%). The EU average hides wide differences in developments in individual Member States. While every Member State saw increases in consumption year-on-year, those range from considerable grows in Poland (+24%), Croatia (+16%), Slovakia (+16%) to the small increases reported in Sweden (+1%), Finland (+2%) and Portugal (+3%).

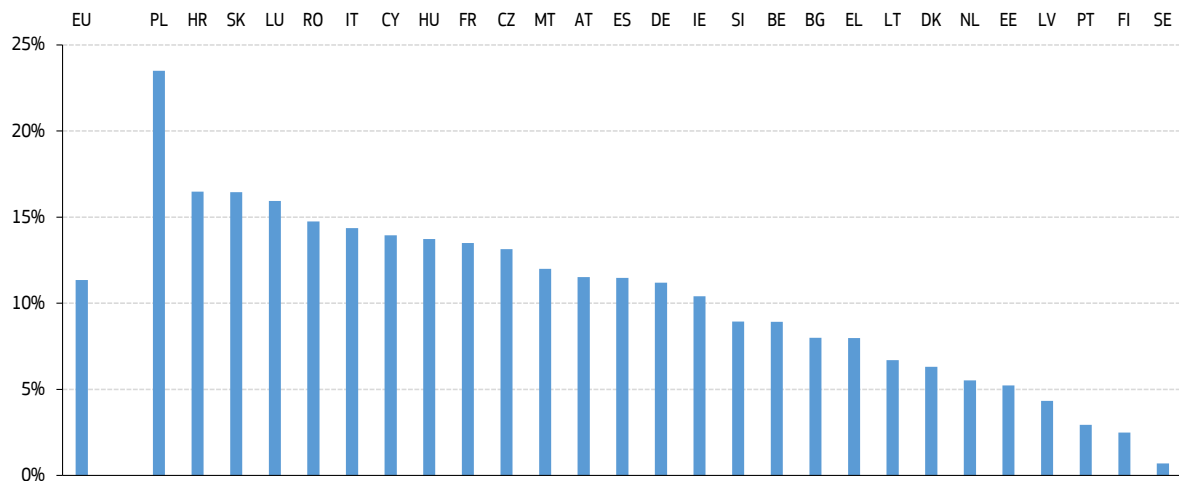
**Figure 2 – Monthly EU electricity consumption**



Source: Eurostat

- Figure 3** sums up changes in electricity consumption between the second quarter of 2020 and Q2 2021. Large increases in electricity consumption occurred in Central Eastern and Southern European regions due to a general ease of COVID lockdown measures. EU-wide consumption rebounded by 11% on the back the steady recovery on industrial activity and ease of lockdowns. Heating and cooling demand also influenced the rise in demand during the quarter.

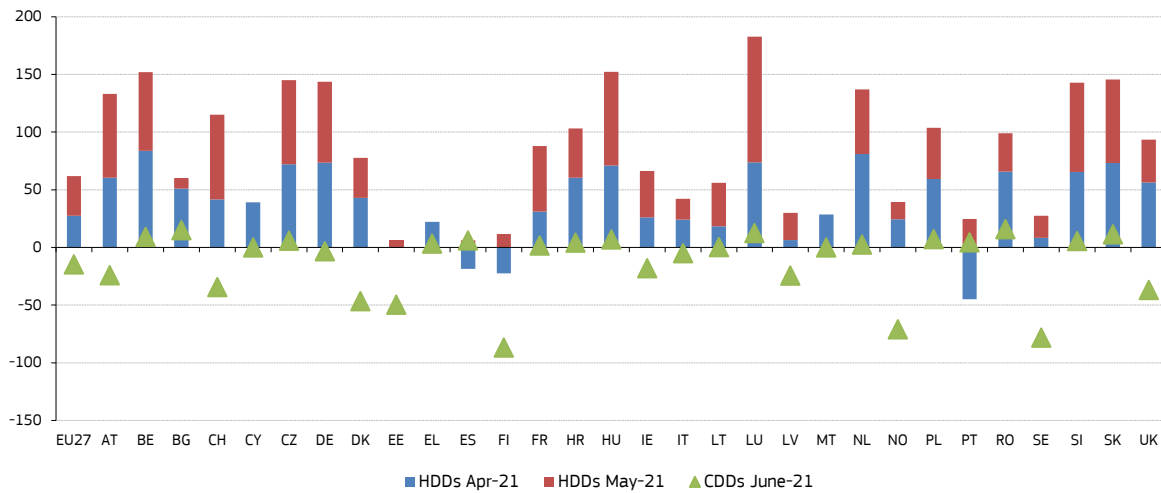
**Figure 3 – Annual changes in electricity consumption in Q2 2020 and Q2 2021 by Member State**



Source: Eurostat

- Figure 4** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average (a period between 1978 and 2018) in Q2 2021. EU-wide, the reference quarter was colder than usual, registering 47 HDDs above the long-term average. This means that temperatures were about 0.5 degree Celsius lower than usual. Most of the deviations took place in May, and to a lower extent in April; meaning that the first part of the European spring was unusually cold. However, higher-than-usual temperatures were measured in the northern part of the continent, mostly during June (Finland, Sweden, Estonia and Norway). Countries such as Luxembourg, Belgium, Hungary, Slovakia and Slovenia experienced cold spells above the normal, which increased electricity demand and prices.

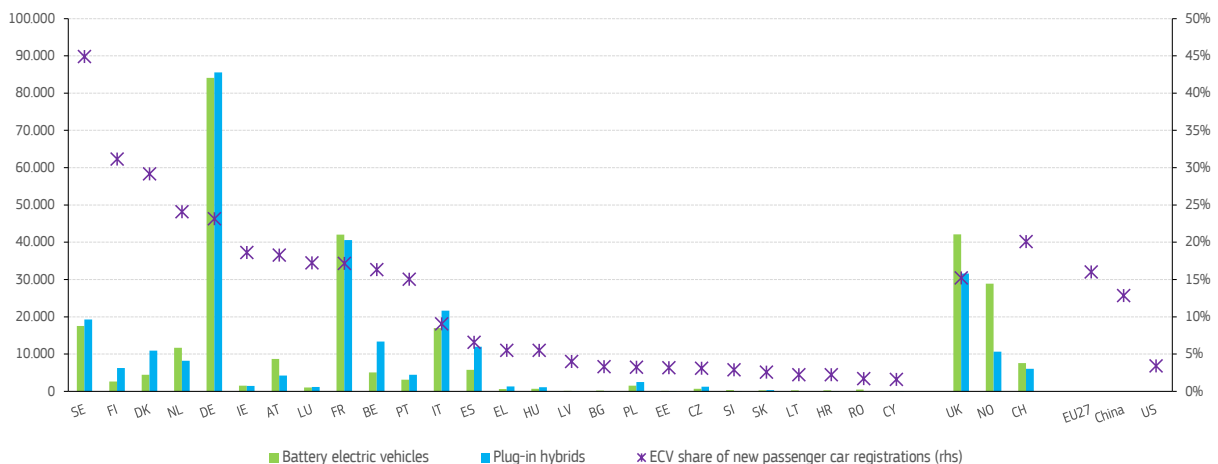
**Figure 4 - Deviation of actual heating days from the long-term average in April-June 2021**



Source: JRC. The colder the weather, the higher the number of HDDs. The hotter the weather in June, the higher the number of CDDs

- Figure 5** shows that demand for electrically chargeable passenger vehicles (ECVs) kept growing in thanks to efforts by major automobile manufacturers to meet stricter emission targets and also thanks to support policies of some Member States aimed at incentivising ECV purchases. Additionally, higher number of models are being advertised at more affordable prices, and uncertainty around the use of the combustion engine increases (Germany, Sweden, Denmark, Ireland and the Netherlands plan to end the sale of new internal combustion cars by 2030). Almost 450,000 new ECVs were registered in the EU in Q2 2021 (+245% year-on-year). These numbers translated into an impressive 16% market share, one and a quarter times compared to China and almost five times higher than in the United States and they represent the second highest quarterly figure on record (close to the impressive numbers of Q4 2020). The plug-in hybrid segment continued to grow (+256% year-on-year to 236,000), while demand for battery electric vehicles grew slightly slower but still at a remarkable pace (+233% year-on-year to 211,000).
- The highest ECV penetration was again observed in Sweden where close to half of the passenger cars sold could be plugged, thanks to significant policy changes. From 1 April, battery-powered electric vehicles (BEV) owners in Sweden are being supported by a total BEV rebate of EUR 6800, up to a maximum of 25% of the vehicle original price. Relatively high ECV market shares were observed in Finland, Denmark, the Netherlands and Germany. The 29% share in Denmark is all the more impressive since it is taking place against the backdrop of zero direct purchase incentives (only tax benefits). Germany retained the position of the largest individual market. Its generous incentive programme, which offers up to 9,000 EUR in direct purchase bonuses, keeps driving up ECV sales to 170,000 in Q2 2021, an increase of more than 300% over the second quarter of 2020. Growth numbers in BEVs were supported most notably by Germany and France, where sales grew 357% and 121% respectively year-on-year. Germany reached the target of 1 million ECVs year-on-year during the reference quarter. 40,000 public charging points can be found in Germany, where 75% of them is operated by utilities.

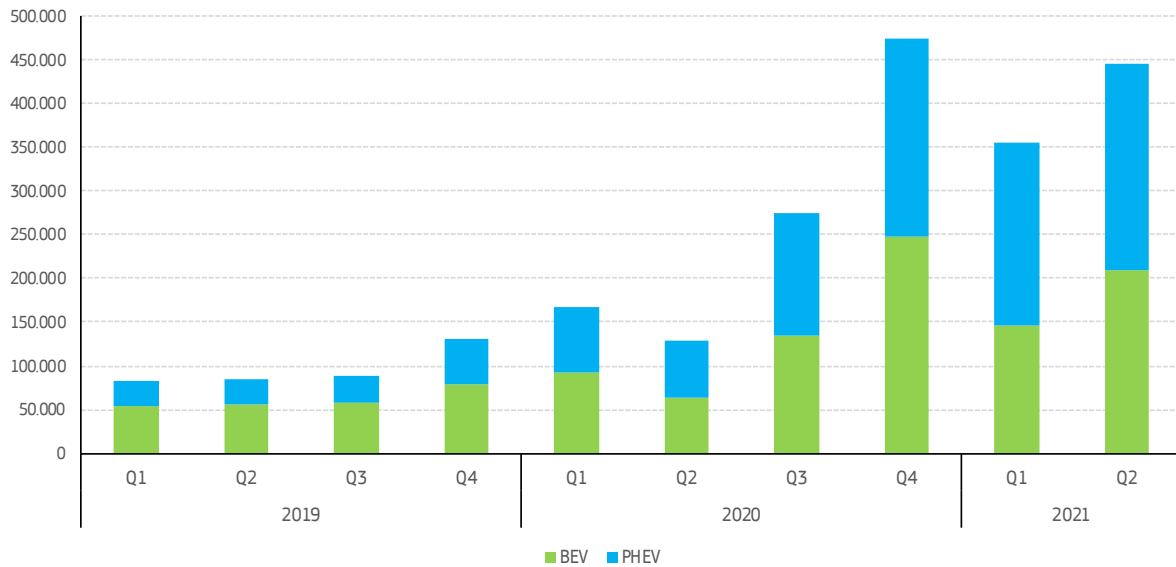
**Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q2 2021**



Source: ACEA, CPCA, BloombergNEF

- Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded during the last quarter of 2020 keeping good track in 2021. Policy support and additional stimulus measures, and the slow but steady recovery in activity after the pandemic have contributed to the impressive increase in ECV numbers. Overall, 1.5 million new ECVs were sold in the EU in the year between Q2 2021 and the same quarter in 2020 (compared to 1.9 million cars with a plug sold in China), more than doubling the existing electric fleet. As the number of ECVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and on network load.

**Figure 6 – Quarterly ECV sales in the EU**

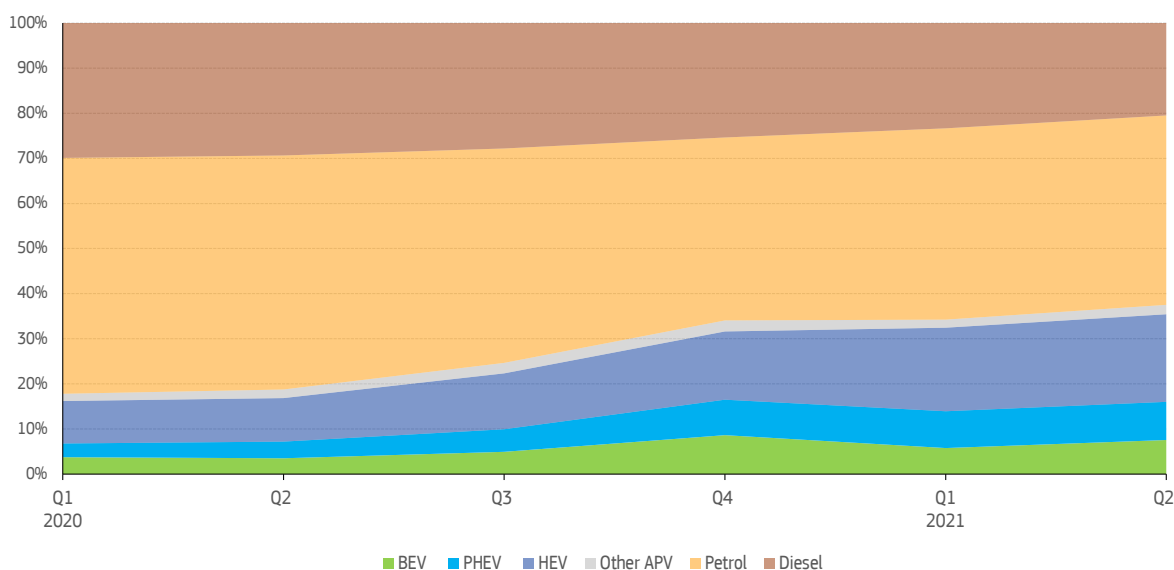


Source: ACEA

- Figure 7** shows the decline of diesel cars, which saw their market share fall to 20% for the first time in Q2 2021, from 30% in Q2 2020. Petrol cars experienced a fall in their share to 42% in Q2 2021, from 52% in the first quarter of the previous year. On the other hand, the shares of new Hybrid electric vehicles (HEV) in the market increased from 10% in Q2 2020, to 19% in Q2 2021. The shares of new ECVs have doubled year-on-year (from 8% in Q2 2020 to 16% in Q2 2021). In July the European Commission presented the proposals to deliver the Green Deal, proposing among other initiatives, strong reduction of CO2 emissions for cars and the support to the growth of the market for zero- and low- emissions vehicles.



**Figure 7 – Evolution of quarterly drivetrain shares in the EU**



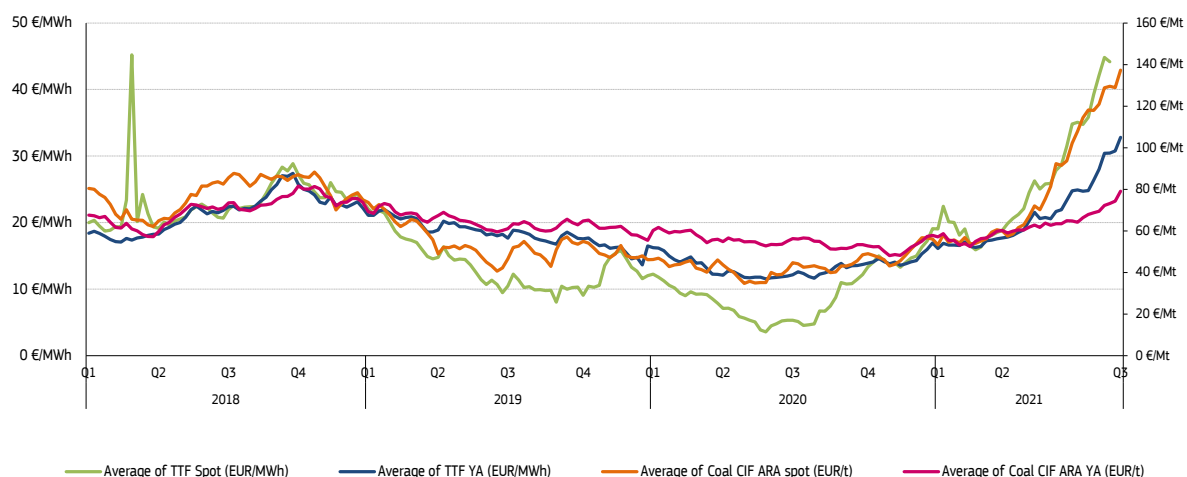
Source: ACEA

- Charging infrastructure is also important to support the uptake of electric vehicles in Europe. According to the [European Automobile Manufacturers' Association \(ACEA\) information](#), 70% of the charging points across the EU are concentrated in three Member States. 30% are located in the Netherlands (66 665), 20.4% in France (45 751) and 19.9% in Germany (44 538). According to ACEA, there is a correlation between sales of ECVs and the availability of charging infrastructure in the Member States of the European Union. The association has noted that countries with lower GDP have overall fewer charging points. As an example, Romania, six times larger in surface than Netherlands, has only 493 charging points, equivalent of 0.2% of the EU total.

## 1.2 Supply side factors

- Figure 8** reports on developments in European coal and gas prices. Thanks to recovering economic activity and increasing demand tied to tighter global supply, prices of coal and gas in the spot market have been rising to record levels during Q2 2021 way above their year-ahead peers. Spot gas prices (represented by the TTF day-ahead contract) rose in the end of last year on the back of forecasts of colder weather and rising storage withdrawals. Falling temperatures provided support for further increases in the gas prices during the first part of Q2 2021. Since then, the trend has been strengthened during the third quarter of 2021, on the back of increasing demand, tight Liquefied Natural Gas (LNG) and pipeline supplies, uncertainty over pipeline projects and high CO2 prices. During mid-September, price rocketed past 70 €/MWh at the TTF hub and several new records were established in quick succession. This situation has significantly undermined the competitive edge of gas-fired power plants in Europe and allowed their coal and lignite competitors to regain some of the lost ground.
- Spot gas prices averaged 25 €/MWh in Q2 2021, a level last seen in 2018. Prices are 36% higher than the previous quarter (Q1 2020) and represent a 372% increase compared to Q2 2020, which reflects level of tightness of the gas market. While in 2020, cheaper gas and the resilience of the carbon market contributed to intensified coal-to-gas and lignite-to-gas switching in 2020, driving down the carbon footprint of EU electricity sector to record lows, current high prices could be detrimental to the reduction of emissions during the current year. Gas prices have a significant influence on electricity wholesale prices. The special section **Focus on the impact of high commodity prices and recovery demand in the electricity sector** will dig deeper into this relevant topic
- Thermal coal spot prices, represented by the CIF ARA contract, have been steadily climbing since March with values over 60 €/t, as a result of supply tightness and higher freight rates. As Chinese economy started to rebound from COVID-19, demand for electricity was enhanced by a warmer-than-average summer, which followed cold spells during last winter in the region. Indonesia, the main exporter of coal to China, has seen reduced shipments up to 15% compared with last year as result of heavy rainfalls. Colombia has also faced disruption in exports due to strikes and Russian exports have been largely diverted to Asia as prices are higher than in Europe. Nonetheless, spot prices are expected to ease in 2022, limited by carbon prices on the upside and low ARA port stocks on the coal price downside. While the market remains tight in the short term, the medium term outlook points to low prices as supply factors normalise after the post-covid demand shock and economies continue to phase-out coal from their power grids. The average CIF ARA spot price averaged 74.3 €/t in the second quarter of 2021, up 95% compared to Q2 2020 and 32% to the first quarter of 2021.

**Figure 8 – Weekly evolution of spot and year-ahead coal and gas prices**



Source: S&P Global Platts

- The European market for emission allowances, shown in **Figure 9**, saw impressive price gains throughout Q2 2021, outweighing those from the first quarter of the year. Several new records were established in quick succession, culminating in a first peak in the middle of May when the closing price climbed above 56 €/tCO<sub>2</sub> for the first time, thanks to rising gas prices and the expectation of upcoming reforms to the Emissions Trading Scheme (ETS). Following the start of the UK Emissions Trading Scheme (UK ETS), prices converged towards mid-June, with consequent price increases when the European Commission put forward the proposal to update the EU ETS to align the Directive with the objective of reducing emissions by at least 55% by 2030. This can be traced down to reforms of several key aspects of the EU ETS which are planned to be introduced in 2021 and which are expected to lead to a tighter supply-demand balance. Several new price records were established as the start-up of more emission-intensive power plants, increasing CO<sub>2</sub> emissions and demand for allowances. Prices broke the barrier of 60 €/tCO<sub>2</sub> for the first time at the end of August following the continuous rise in the price of gas.
- The average CO<sub>2</sub> spot price in Q2 2021, at 50 €/tCO<sub>2</sub>, represented an increase of 33% with respect to Q1 2021 and a change of 136% year-on-year. Higher carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. However, under the current situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not enough to support coal-to-gas fuel switching in power generation (see **Figure 19**). They also tend to drive wholesale electricity prices higher (see **Figure 14**).

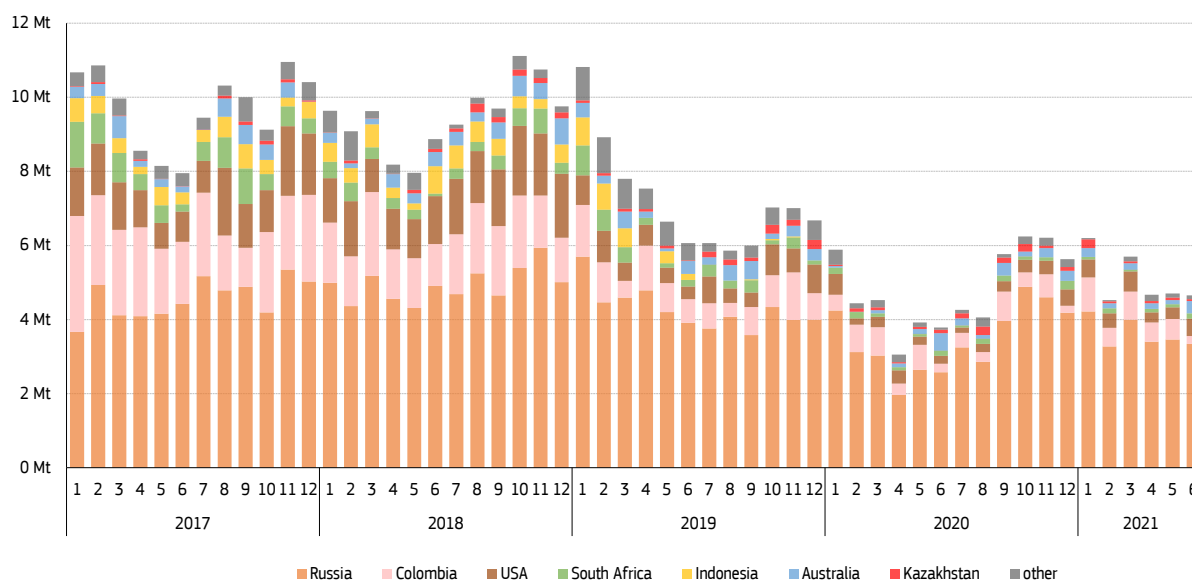
**Figure 9 – Evolution of emission allowance spot prices from 2018**



Source: S&P Global Platts

- As visible from **Figure 10**, monthly thermal coal imports into the EU held at roughly 4.7 Mt in Q2 2021 as electricity demand increased and made more space for fossil fuels in the mix. The total volume of imports increased by 31% year-on-year to 14 Mt in the second quarter of 2021. The estimated EU import bill for thermal coal amounted to €1.1 billion in the reference quarter, 47% higher compared to Q2 2020 enhancing the year-on-year increase in imported volumes of this commodity.
- The largest part of extra-EU thermal coal imports in Q2 2021 came from Russia which accounted for 73% of the total. Russian traders continued to cement their dominant position as most of their rivals find it difficult to compete in the though low-price, low-demand environment. Colombia saw its market share shrinking to 9% compared with 13% in the previous quarter. The position of Australia and Kazakhstan remained almost unchanged (4% and 1% shares respectively). The share of deliveries from US ports slightly decreased from 9% to 8%. Shares of other trading partners were not relevant.

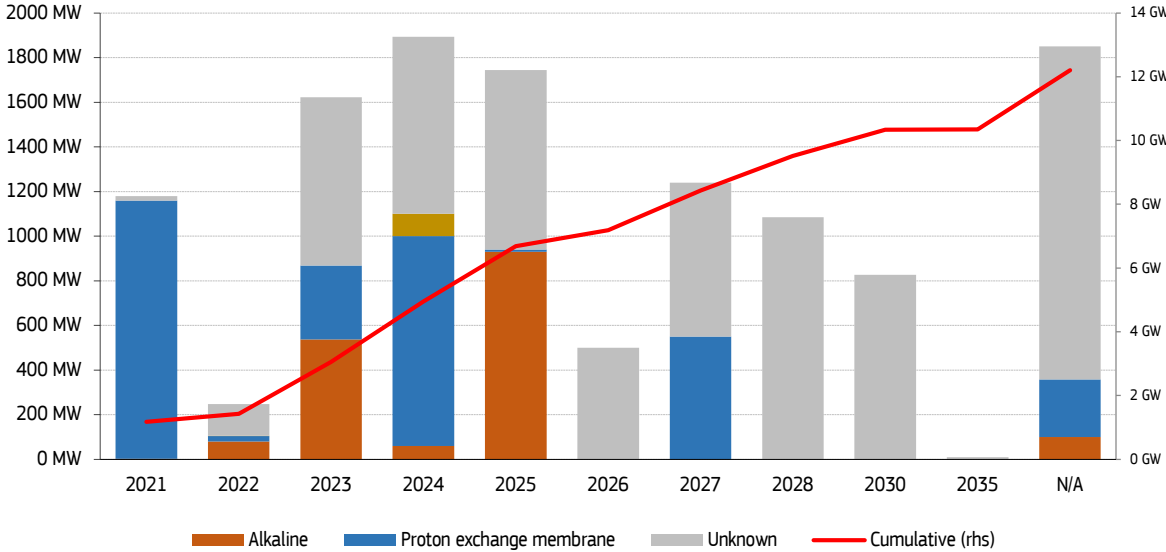
**Figure 10 – Extra-EU thermal coal import sources and monthly imported quantities in the EU**



Source: Eurostat

- **Figure 11** presents announced electrolysis projects by technology in the European Union. So far, 12 GW of electrolyser projects to produce hydrogen have been proposed in Member States. Net zero emissions targets, associated strategies for the uptake of hydrogen capacity and high carbon prices are driving Hydrogen deployment in Europe. Carbon prices also support the uptake of hydrogen, turning the clean production of H<sub>2</sub> competitive in comparison with fossil fuels in hard-to-decarbonise industries. Several projects to produce clean hydrogen have been proposed using available funds from the Recovery and Resilience Facility and Horizon Europe programmes.
- Alkaline and proton exchange membrane (PEM) are the two most mature electrolyser technologies. Both share the same principles of electrolysis. Alkaline water electrolysis is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). A proton exchange membrane (or polymer-electrolyte membrane) is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes.

**Figure 11 – Announced hydrogen electrolyser capacity additions by planned commissioning year in the EU**



Source: BloombergNEF, Hydrogen Projects Database

Note: Graphic includes only officially announced projects that have disclosed electrolyser capacity and are expected to come online by 2030. N/A and unknown mean that the developer has not disclosed the project’s commissioning year and the technology to produce the hydrogen has not been announced yet.

## 2 European wholesale markets

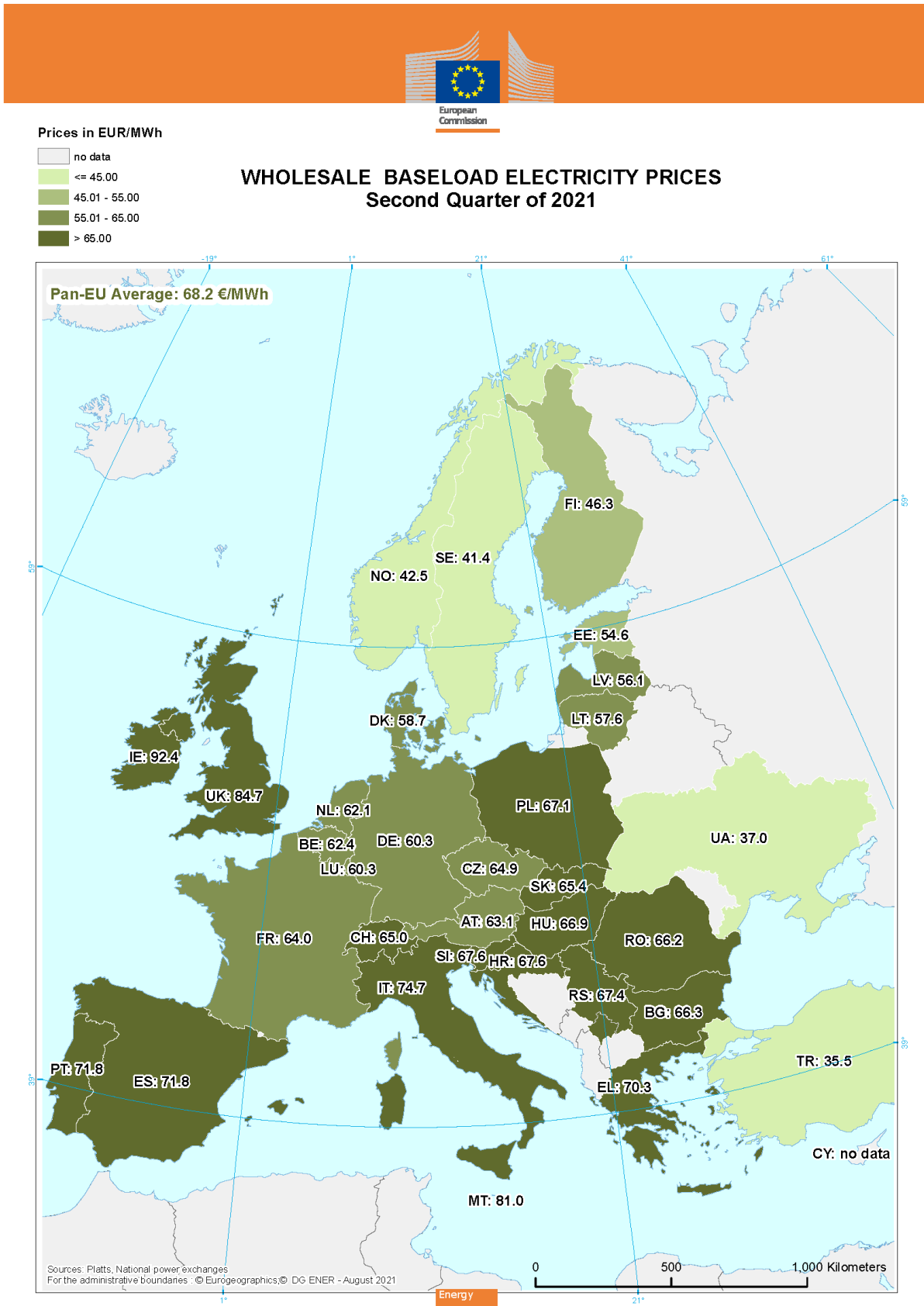
### 2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q2 2021. The reference quarter saw a sharp increase compared to Q2 2020, as prices reached 13-year highs in many European markets, on the back of high commodity prices (gas, coal and CO<sub>2</sub>) and increasing demand due to the steady but strong recovery of industrial and labour activity and low/high temperatures. Practically every European country experienced a considerable surge in prices (changes over 100% and in some cases, above 200%<sup>1</sup>). Although spot prices in the Nordic region experienced one of the largest year-on-year increases, the cheapest baseload power in Europe on the day-ahead market was still available in this market. Countries such as Sweden, presented values of 41 €/MWh on average. Likewise, Norway reported prices around 43 €/MWh on average. Most markets moved between 60 and 70 €/MWh. Ireland reported the highest quarterly average price (92 €/MWh), which was 258% higher than in Q2 2020 (96% above Q2 2019 levels). The United Kingdom became the second most expensive market with an average baseload price of 85 €/MWh, which was 215% higher compared to the same period last year (78% above Q2 2019 levels).
- The pan-EU average of day-ahead baseload prices reached 68 €/MWh in the reference quarter, up 158% in a year-on-year comparison. Compared to Q2 2019, the quarterly average price rose by 58%.
- The largest year-on-year price increases were registered in Norway (+790%), Ireland (258%), France (255%) and Sweden (+237%), on the back of an overall recovery in demand, lower/higher than average temperatures, combined with high commodity prices. Conversely, Greece experienced the least increase in prices during Q2 2021 (+6%). It should be noted that the prices during the pandemic last year were unusually low (especially during Q2 2020).

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<sup>1</sup> Eleven MS have experienced increases over 200% compared to Q2 2020

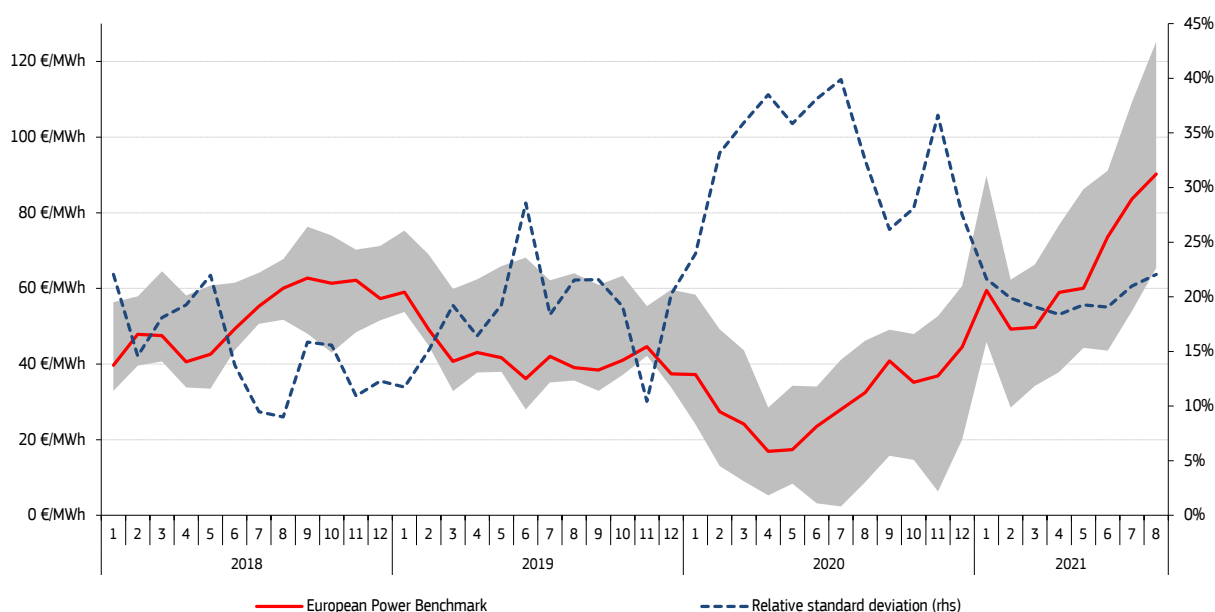
**Figure 12 – Comparison of average wholesale baseload electricity prices, first quarter of 2021**



Source: European wholesale power exchanges, government agencies and intermediaries

- Figure 13** shows the European Power Benchmark of nine markets and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of regional prices. Both the shaded band and the relative standard deviation metric show that despite wholesale prices increasing across different regional markets in Q2 2021, divergence levels started to increase, as average prices in countries and regions that traditionally form the lower part of the spectrum (Nord Pool, Germany, France) registered increases across the board during the reference quarter. Central Western and Eastern Europe, the Nordic region, Great Britain and the Iberian Peninsula experienced a surge in prices on the back of rising fuel and carbon costs and recovering demand fostered by cold and warm weather. The Nordic region, experienced a cold first half of the spring which drove power demand, resulting in a steep increase in prices. Great Britain registered a robust demand, which combined with high gas prices and low wind availability, saw average prices surging during the quarter. This made Britain the most expensive market in Europe during the second quarter of 2021. The European Power Benchmark averaged 68 €/MWh in Q2 2021. This was 158% higher than in the same quarter last year. Prices were still 58% higher than Q2 2019 (pre-pandemic levels). The rising trend continued in the following months on the back of extremely high fuel prices. In September, electricity prices in many markets, including Spain, France and Germany, reached all-time record highs.

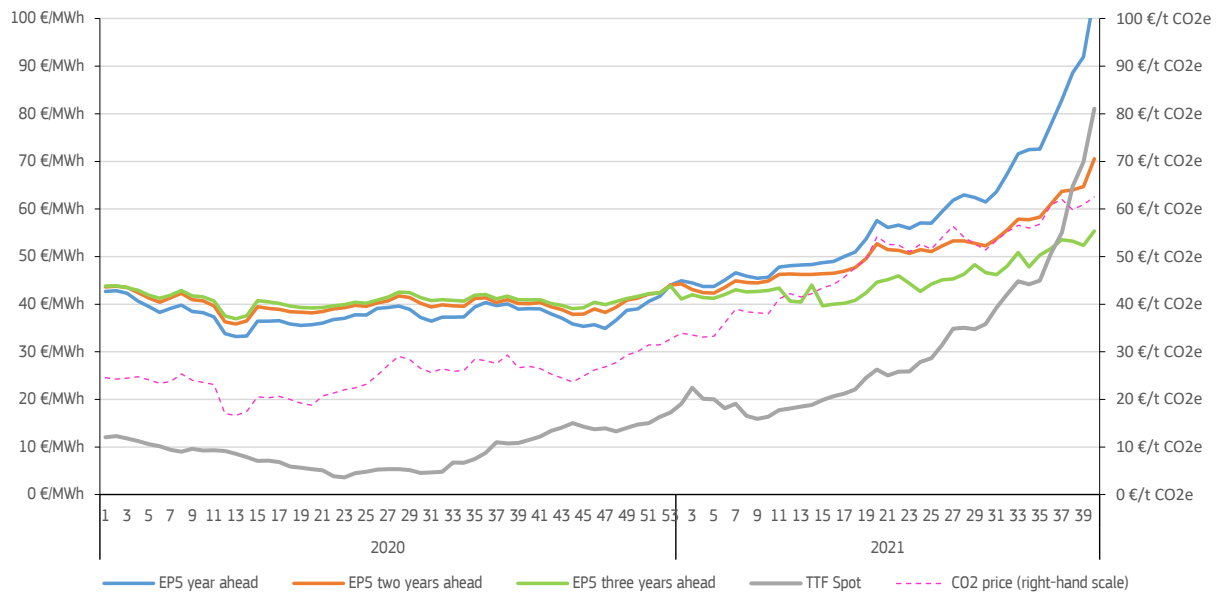
**Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices**



Source: Platts, European power exchanges. The shaded area delineates the spectrum of prices across European regions.

- A consumption-weighted futures benchmark (EPS) of five markets, shown in **Figure 14**, reveals that notably gas prices have been the main driver behind changing expectations of future electricity prices since the first quarter of the year. The rally in gas that has been taken place since March 2021, lifted the benchmark above pre-crisis levels and into all-time record highs. The TTF spot price surged 68% during the second quarter of the year, whereas the year ahead benchmark increased 29% in the same period. Carbon prices have also been rising since November 2020, registering a 30% increase during Q2 2021. This increase has also influenced electricity prices, but to a lower extent than gas prices.
- During the first week of Q2 2021, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 48 €/MWh, 46 €/MWh and 40 €/MWh; whereas at the end of June, these three values reached 60 €/MWh, 52 €/MWh and 45 €/MWh. In addition, the discount of the year-ahead contract to the spot market indicates a strong backwardation which has been developing in parallel with the latest price increase in spot markets. The discount of the year-ahead contract to the spot market grew from -1 €/MWh to 12 €/MWh during Q2 2021, and by the end of September this difference rose to 41 €/MWh, underlying that the market anticipates a correction of the price levels in the mid-term future.

**Figure 14 – Weekly futures baseload prices – weighted average of 5 European markets**

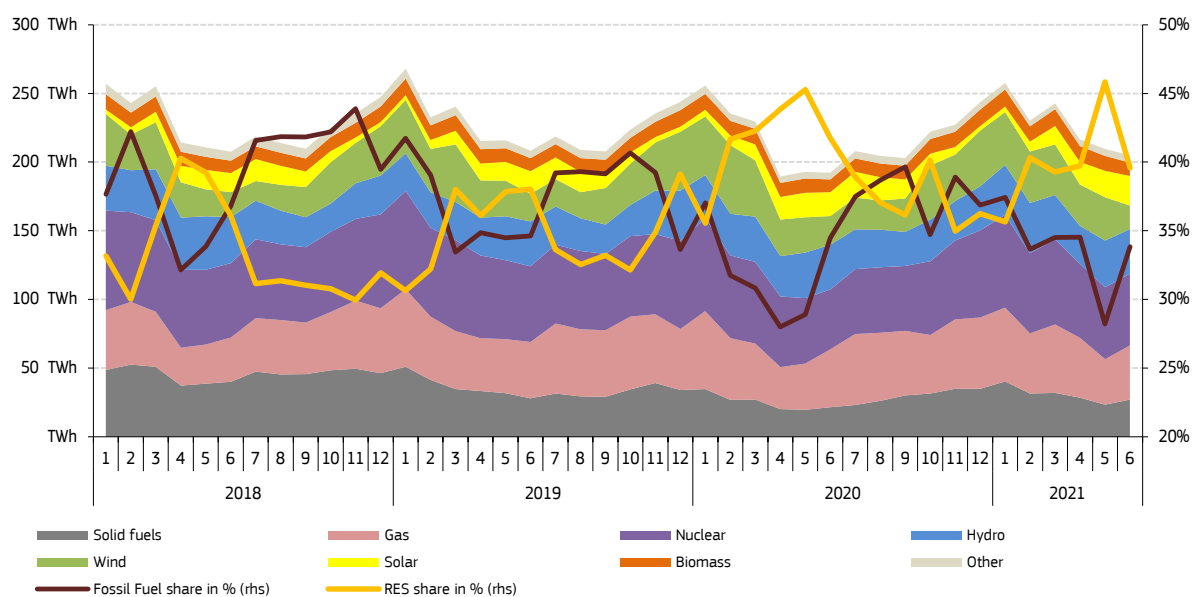


Source: Platts.

- Figure 15** shows the monthly evolution of the electricity mix in the EU. A combination of recovering industrial activity and increasing electricity demand supported by colder and higher-than usual temperatures made more space for fossil fuels in the mix. However, the share of energy produced by renewables still managed to reach 42% in Q2 2021 (although lower than the 44% share of renewables in Q2 2020), while fossil fuel generation (coal, gas and oil) stayed below registering 32% of the share during the quarter. Fossil fuel generation increased its share in the mix compared with the 30% observed in Q2 2020. Nuclear generation remained at the same level of generation compared with the reference quarter in 2020 (25%).
- Within the fossil fuels complex, coal gained terrain both in absolute and relative terms compared to Q2 2020 due to rising demand (higher than a year earlier) and high gas prices reversing the coal-to gas switching trend of the previous quarters, despite rising carbon prices. Coal's share in the mix rose to 12%. Meanwhile, less CO<sub>2</sub>-intensive gas generation practically saw its share unchanged at 18% in the reference quarter. In absolute terms, coal-based generation rose by 17 TWh year-on-year, while gas-fired power plants' output increased by almost 10 TWh. Renewables, generated 12 TWh of electricity more year-on-year on the back of higher solar and wind generation.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 15**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of CO<sub>2</sub> prices. This stems mainly from low production costs of the input fuel, which is usually mined in close proximity to power plants that use it. Conversely, lignite generators have a larger carbon footprint per generated MWh (by about 20% compared to coal), which penalises them more when emission allowances become costlier. Emission allowances were 136% more expensive in Q2 2021 compared to Q2 2020, but this was compensated by rising gas and hard coal prices, which meant that lignite power plants weathered the reference quarter in a better shape. In the end, lignite-based generation in Q2 2021 rose by 28% year-on-year (more than 9 TWh), while coal-fired generation increased by 30% year-on-year (or 8 TWh).



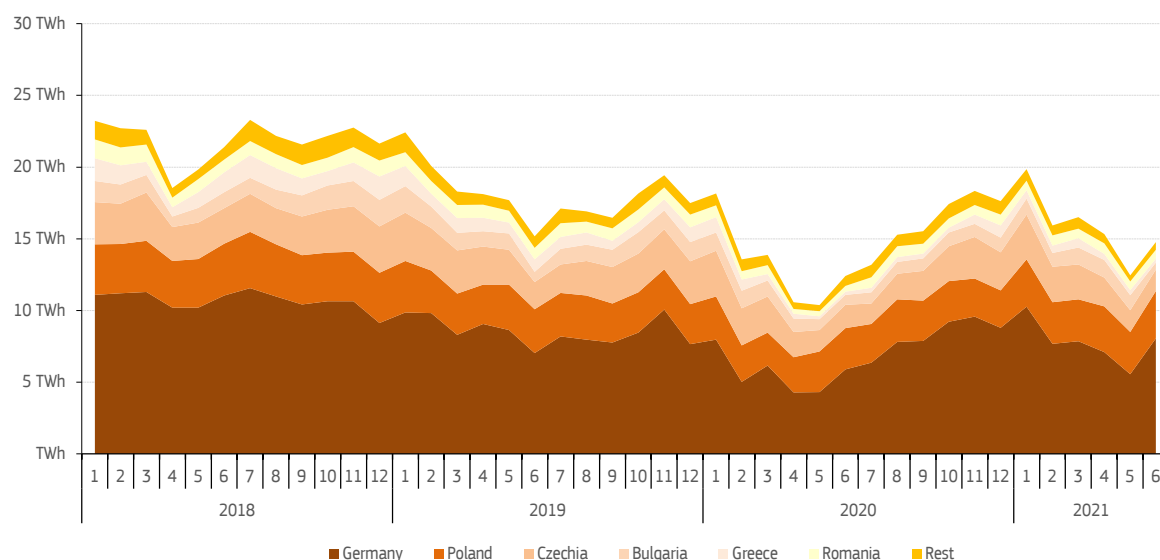
**Figure 15 – Monthly electricity generation mix in the EU**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation. Fossil fuel share calculation covers power generation from coal, lignite, gas and oil.

- Figure 16** shows that after a large covid-related drop during spring and summer months, lignite generation staged a powerful comeback during April and June, helped by rising gas prices (which decreased the competitive edge of gas-fired power plants) and recovering demand. Every Member State with lignite-fired capacity increased its output during Q2 2021. Monthly output peaked in April and June at roughly 15 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 43% year-on-year in Q2 2021, due to increasing demand and falling hydro and offshore wind output. Lignite-fired generation in Poland increased 16% year-on-year in Q2 2021. The output of the Czech lignite fleet rose by 3% year-on-year. The three Member States accounted for 83% of the total lignite-based generation in the EU in Q2 2021. In Greece, lignite generation increased by 36% year-on-year on the back of rising demand of decreased biomass and wind output. In Bulgaria, growing demand and falling wind output facilitated the generation of additional volumes of lignite (15%) compared to Q2 2020. Lignite power plants reached a 7% share in the EU generation mix in Q2 2021 (up from 6% on Q2 2020) and were responsible for approximately 31% of the electricity sector’s total carbon emissions.

**Figure 16 – Monthly generation of lignite power plants in the EU**



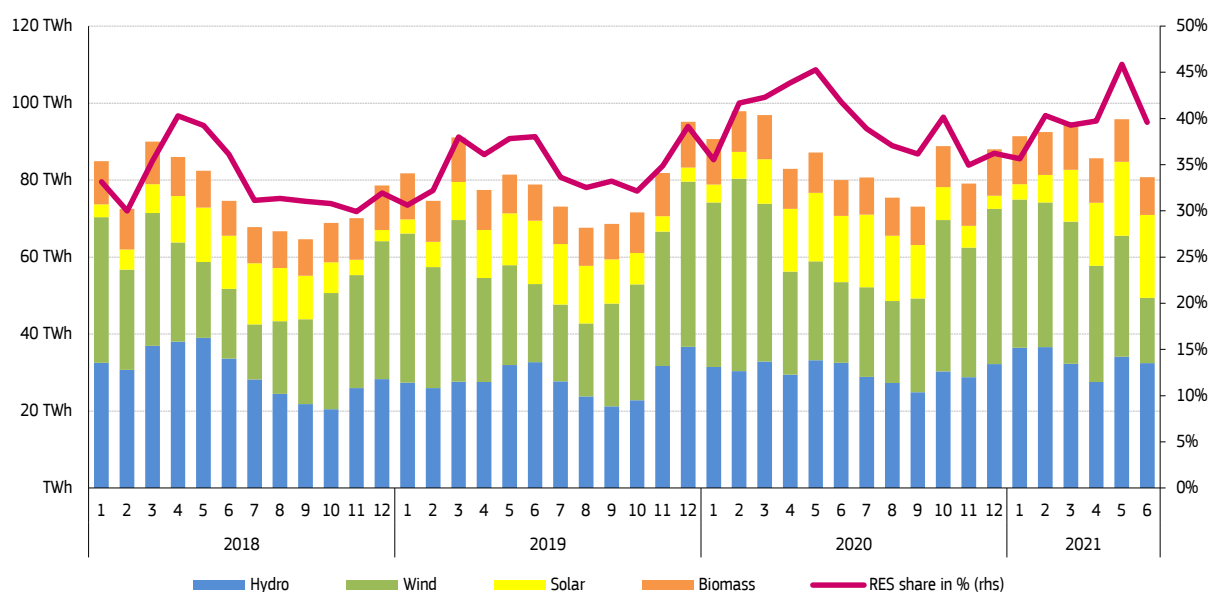
Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- Figure 17** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 42% in Q2 2021, higher compared to Q1 2021, but still somewhat

lower than during the same quarter last year (44%). Stronger demand contributed to the slight year-on-year decrease in renewable penetration.

- Most of the decrease in renewable generation came from hydro (-1 TWh) while solar and wind experienced gains (+6 TWh and +5TWh respectively) compared with the reference quarter in 2020. Largest decrease in hydro generation came from France and Italy, where hydro generation fell by 10% and 7% respectively compared with Q2 2020, as a result of low stock levels and limited precipitations.
- Wind gains during the reference quarter were reported in France (+16%), Belgium and Netherlands (+11%) and Spain (+10%), among other Member States. Conversely, the UK experienced cold but calm weather, which resulted in a decline of wind generation by 11% and 15% respectively (onshore and offshore). On the other side of the coin, Finland and Czechia increased their wind onshore output by 18% on a year-on-year basis.
- Thanks to newly added panels, solar PV generation rose by 11% in Q2 2021 to almost 6 TWh, more than ten times than oil-fired generation. The increase was almost singlehandedly driven by Spain. Solar generation rose 27% year-on-year. Also the share of solar generation in Spain reached 13% in Q2 2021, putting it within striking distance of hard coal (2%).

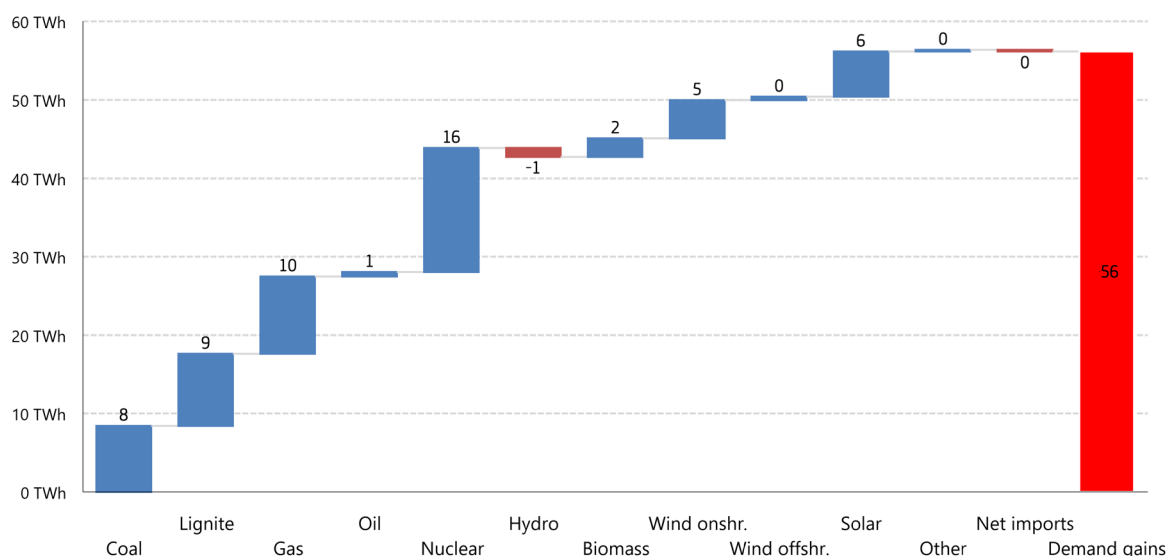
**Figure 17 – Monthly renewable generation in the EU and the share of renewables in the power mix**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 18** visualises changes in the EU27 electricity generation balance in the reference quarter compared to the same quarter a year before. The space for conventional power plants' running hours was increased by major shifts especially on the demand side. The steady but strong economic recovery from the coronavirus pandemic and temperatures above and below-average increased power demand by 56 TWh. As a result, fossil fuels increased their generation (+28 TWh) and nuclear slightly grew its output (+2 TWh). Renewable sources generation also rose (+12 TWh), whereas net imports remained almost unchanged. The EU27 net balance finished unchanged in Q2 2021. An increase in power demand during the quarter strengthen fossil fuel generation. All in all, coal increased its output by 8 TWh, lignite by 9 TWh, gas rose by 10 TWh, while oil slightly increased by 1 TWh in Q2 2021. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 19% year-on-year in Q2 2021 due to the larger use of fossil fuels. However, emissions were still 10% lower than in Q2 2019.
- Most of the main drivers behind the Q2 2021 increase in carbon emissions were exceptional (strong covid-related demand recovery, colder and warmer-than average weather, less than expected renewable generation). Given the high prices of commodities (gas, coal and CO<sub>2</sub>), combined with the increasing demand in line with the return to normal industrial and labour activity in Europe, it is likely that both the power sector's average carbon footprint and carbon intensity will rise in 2021.

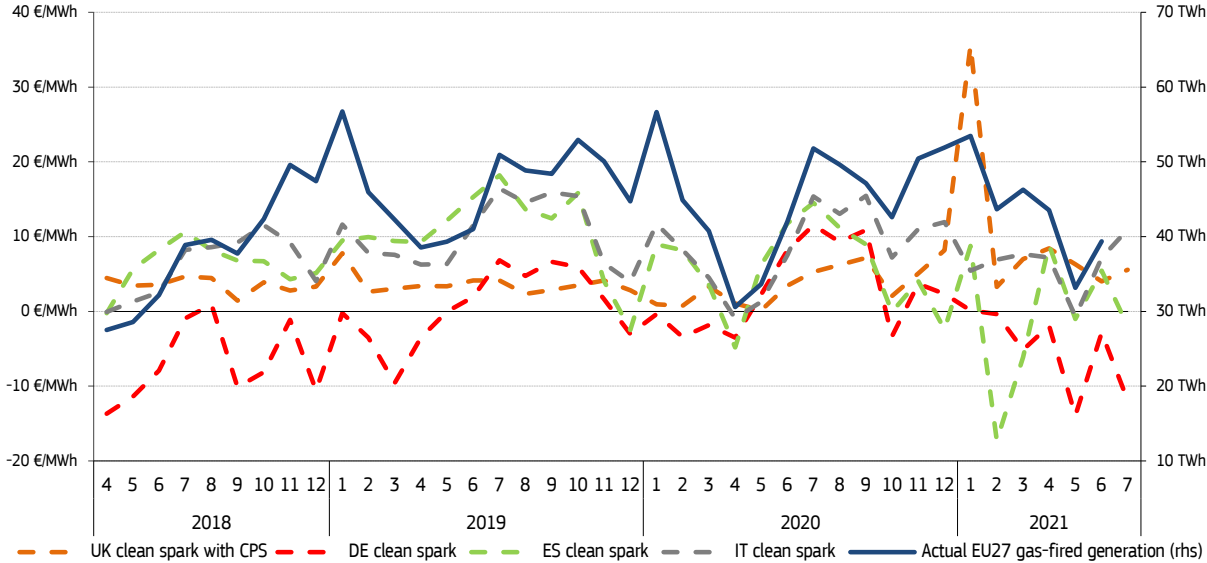
**Figure 18 – Changes in power generation in the EU between Q2 2020 and Q2 2021**



Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation

- The following two figures report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at their clean spark indicators. Gas reduced its traditional competitiveness advantage to coal on average in Q2 2021. During the whole quarter of reference, rapidly rising gas prices resulted in coal gaining the upper hand, despite rising carbon prices. Overall, mix clean spark spread in the UK, Spain and Italy was driven by rising electricity and gas prices. High prices created health margins not only for gas, but also for coal generators, as the spark spreads climbed into the positive area during the reference quarter. The increasing rally in gas prices during 2021 has been a combination of rising global demand and low storage levels. As such, coal usage to reach electricity demand could keep increasing throughout the year.
- As shown in **Figure 19**, in the UK and Italy, the profitability of gas firing for electricity generation remained mostly in positive territory for a plant with an average efficiency during Q2 2021 (as opposed to the German clean spark spread who has not been in positive territory since January 2021). However, the good numbers in April were out weighted by the mix and then downward trend of the following months for the four markets. The highest [clean spark spreads](#) in Q2 2021 were assessed in Spain (9 €/MWh), followed closely by the UK (8 €/MWh). The lowest was presented in Germany during May (- 14 €/MWh). Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 116 TWh in the reference quarter, up by 9% compared to Q2 2020.

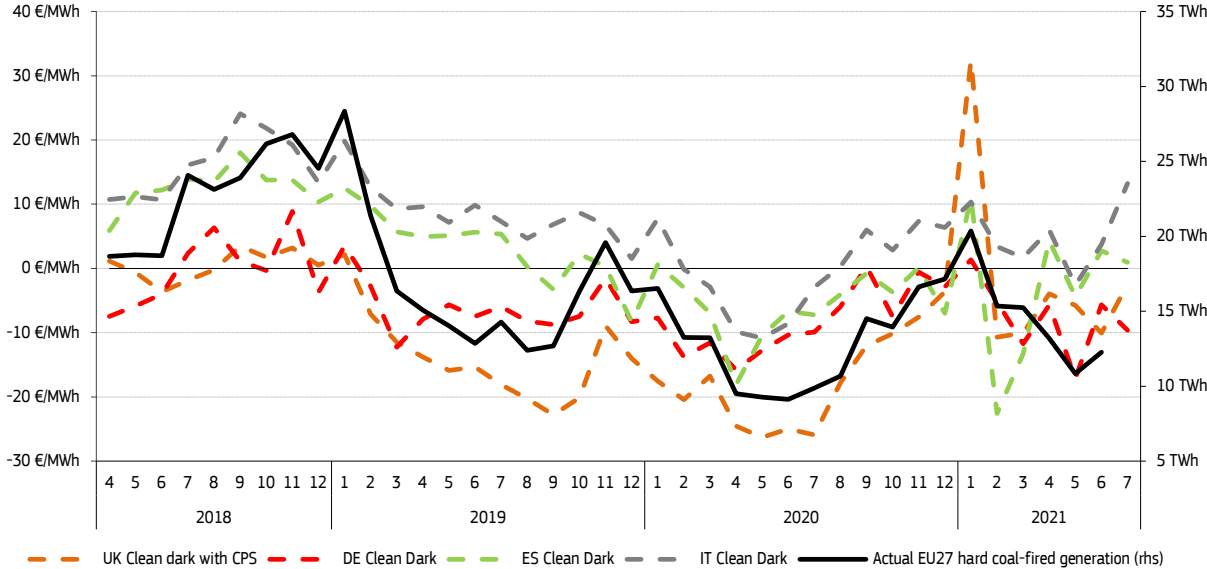
**Figure 19 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU**



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 20** shows that Italy, followed by Spain experienced the most profitable coal-fired power generation in Q2 2021. In April, Italy and Spain presented spikes in the profitability indicator for an average plant, despite rising coal and carbon prices. [Clean dark spreads](#) in Italy averaged 2 €/MWh in Q2 2021, lower than in the case of gas-fired power plants. Coal generation in Spain declined by 18% year-on-year in Q2 2021, with only few units remaining in the market. German coal generators, in contrast, increased their output by 65% year-on-year in Q2 2021, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and no other capacities were available as replacement to meet increasing electricity demand.

**Figure 20 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU**

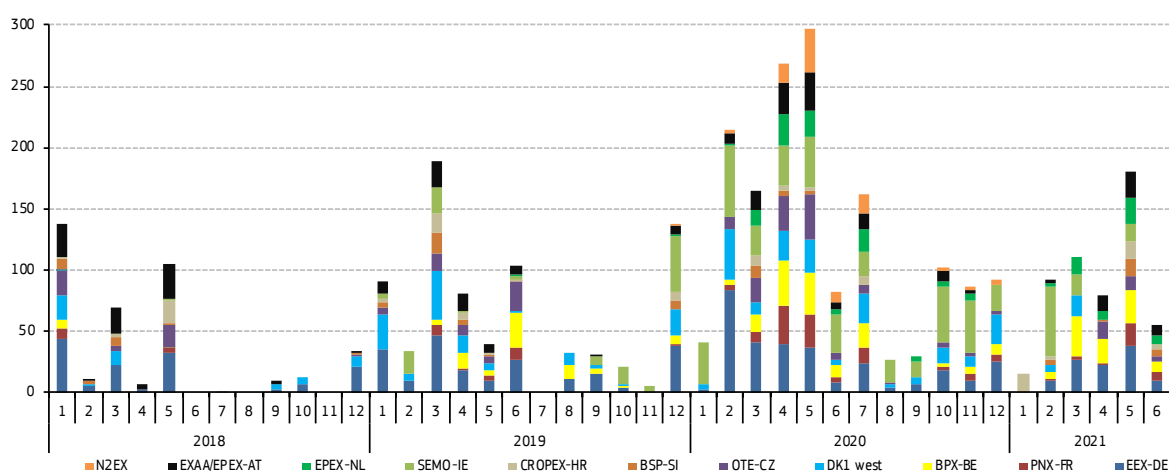


Source: ENTSO-E, Eurostat, Bloomberg

- Figure 21** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected European markets. Negative hourly prices usually appear when demand for electricity is lower than expected and when intermittent renewable generation is abundant, combined with ongoing relatively non-flexible large baseload power generation (e.g.: nuclear or lignite). In such cases, conventional power plants offer their output for a negative price in an effort to avoid switching the unit off and having to go through the costly and high-maintenance operation of restarting the facility when they want to enter the market again.

- The number of hours with negative wholesale prices in Q2 2021 (362) was 44% lower in the observed bidding zones than in the previous Q2. Most of the falls into negative territory occurred in April and May of the reference quarter and took place mostly during weekends when low consumption coincided with high renewable generation. The highest number of negative prices was recorded on 5 April (Easter Monday) when strong wind speed combined with strong solar generation and weak demand, pushed most of Central Western Europe markets (German, Dutch, Belgium, Austrian, Swiss) and Nordic markets (Swedish and Danish) prices below zero during several hours of the day. Wind generation covered a large part of the German consumption during that day. German baseload power settled at -17 €/MWh. Wind generation covered 28% of the European power demand, with a total output of 2.1 TWh during that day.
- The German zone recorded the highest number of negative hourly prices (69) in Q2 2021 and was trailed by Belgium (54), the Danish mainland (DK1) zone (48), and Austria (42). Croatia and Slovenia experienced 20 negative hourly prices during Q2 2021 (+186% year-on-year), Hungary recorded an increase of 167% of negative hourly prices in Q2 2021. The aftermath of the pandemic has made balancing the grid a harder task and accentuated the need for more flexibility in the European power system in both directions. It has also intensified the search for market instruments that would find a proper value of flexibility.

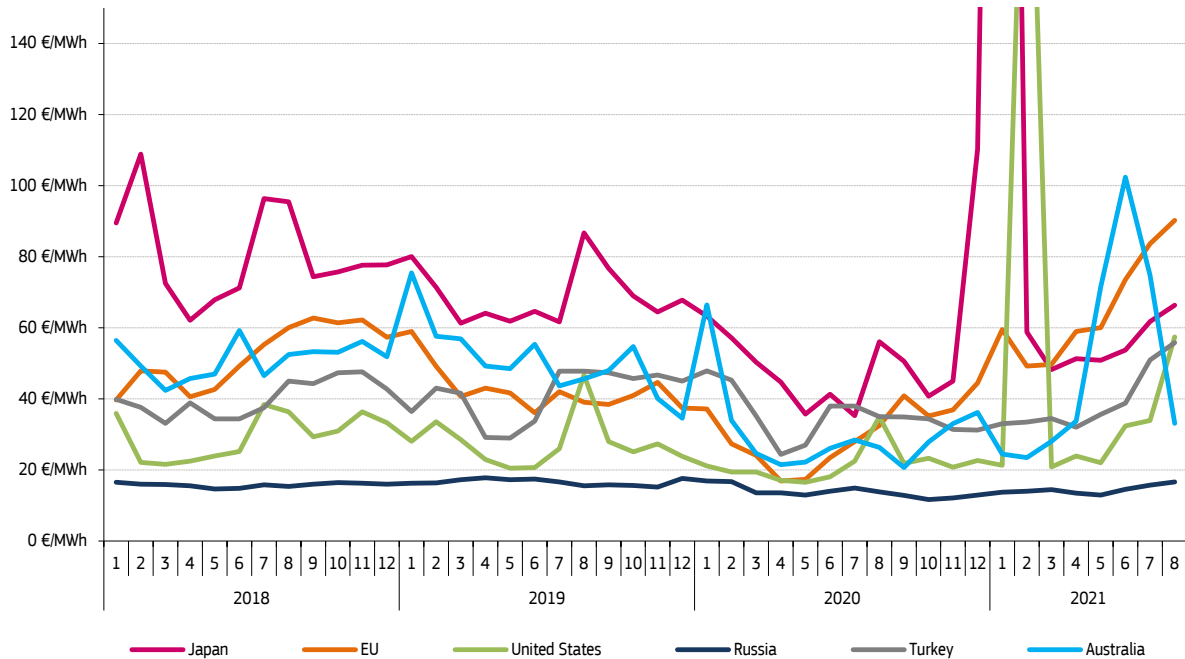
**Figure 21 – Number of negative hourly wholesale prices on selected day-ahead trading platforms**



Source: Platts, ENTSO-E. For Austria, the EXAA market is used prior to October 2018, and the EPEX market is used afterwards.

- **Figure 22** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices returning to pre-pandemic levels in Q2 2021. In the U.S., after the dramatic price spikes of the last quarter in Texas (ERCOT), wholesale electricity prices rose through the reference quarter by 40% in comparison with Q2 2020, influenced by heatwaves during June in some States, leading to new 12-month high wholesale prices in New England (ISONE) and the Northwest (Mid-C).
- Japan experienced an increase of 28% in prices during Q2 2021. Limited gas supply due to steep LNG prices, led to low gas-fired electricity generation. China and South Korea have been equally exposed to tightening LNG market fundamentals, turning the gas scarcity into a regional issue.
- With the exception of Australia, European wholesale prices were the highest of the observed group in Q2 2021, reaching 64 €/MWh. Russia remained at the other end of the spectrum with 14 €/MWh, which was still 1% higher than in the same quarter last year. Australian prices surged by almost 200% year-on-year across all regional markets throughout Q2 2021, on the back of increasing demand, high gas prices and several unplanned outages of thermal generators which drove significant price volatility in the National Electricity Market (NEM).

**Figure 22 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)**

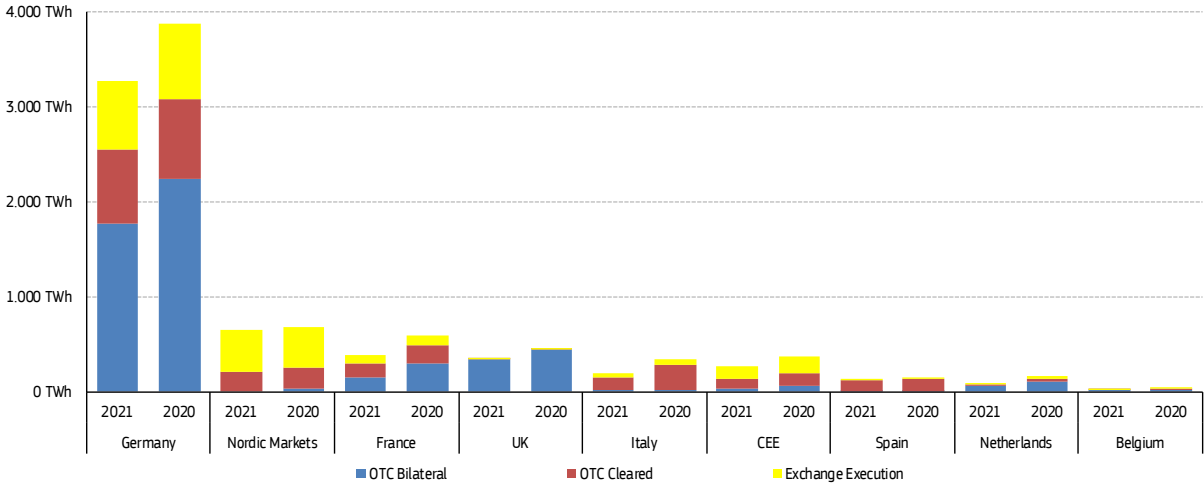


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States.

## 2.2 Traded volumes and cross border flows

- Figure 23** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Most markets and regions witnessed a year-on-year decline in trading activity in Q2 2021. The largest annual falls in total traded volumes were registered in Italy (-43%), the Netherlands (-39%) and France (-35%), split approximately equal by the OTC and Exchange sectors (except in France where losses were driven mainly by the OTC sector). The total traded volume in all markets under observation fell by 19% year-on-year to 5412 TWh in Q2 2021.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, total volumes reached 3276 TWh (equivalent to 61% of the total traded volumes under observation in Q2 2021). Activity fell year-on-year basis both at exchanges (-9%) and in OTC contracts (-17%) in 2021. The market share of exchanges experienced a slight increase compared to 2020 (+2%). Similar relative decreases in activity were visible in the UK where total volumes fell by 21% to 360 TWh. Spain, the UK and Italy markets registered the largest decrease in bilateral OTC deals (-68%, -49%, and -48% respectively). The market share of power exchanges expanded from 24% to 27% year-on-year. The largest falls in exchange-based volumes were reported in the Netherlands (-48%) and Italy (-42%). Overall, exchange-based trading volumes decreased by 143 TWh in Q2 2021. The OTC segment traded 1109 TWh of electricity less in 2021 compared to the same reference quarter in 2020, as a result of lower volumes changing hands in Germany, France and Italy.

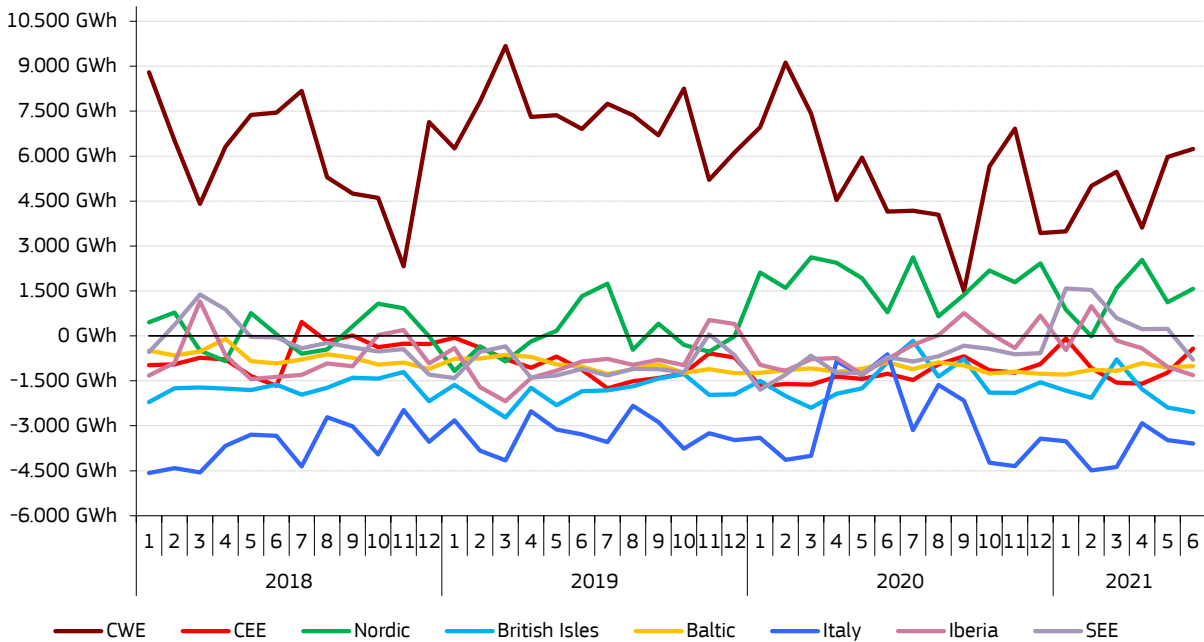
**Figure 23 – Annual change in traded volume of electricity on the most liquid European markets**



Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations

- Figure 24** reports on the regional cross-border flows of electricity. Central Western Europe retained its position of the main exporting region, having plentiful and diverse generation capacities and a central position suitable to supply other regions. During the second quarter of 2021, CWE exploited its strong potential with 15 TWh of net exports and was again the largest source of outflows, increasing flows by 8% in comparison with Q2 2020. The increase can be traced mainly to higher generation within CWE market, which increased the availability of exports. Thanks to the increasing levels of hydro reservoirs, the Nordic region recorded a surplus of 5 TWh in the reference quarter, 2% above from the net exports in Q2 2020. South Eastern Europe registered the return to its condition of net importer even though only by a slight margin (-0.3 TWh), still a significant improvement compared to Q2 2020 (-3 TWh). The Iberian Peninsula also fell back to its traditional condition of net importer, as increasing power demand and reduced hydro conditions resulted in a shortfall of -3 TWh during the reference quarter.
- The rest of the regions ended up in deficit. Italian net imports rose by 261% year-on-year to 10 TWh in Q2 2021, supported by increasing demand due to post-pandemic recovery, above-average temperatures and shortfall in renewables output. Net flows to the British Isles increased compared to Q2 2020 at 7 TWh. The CEE region's net position (-3 TWh) improved by 20% in Q2 2021 compared to Q2 2020.

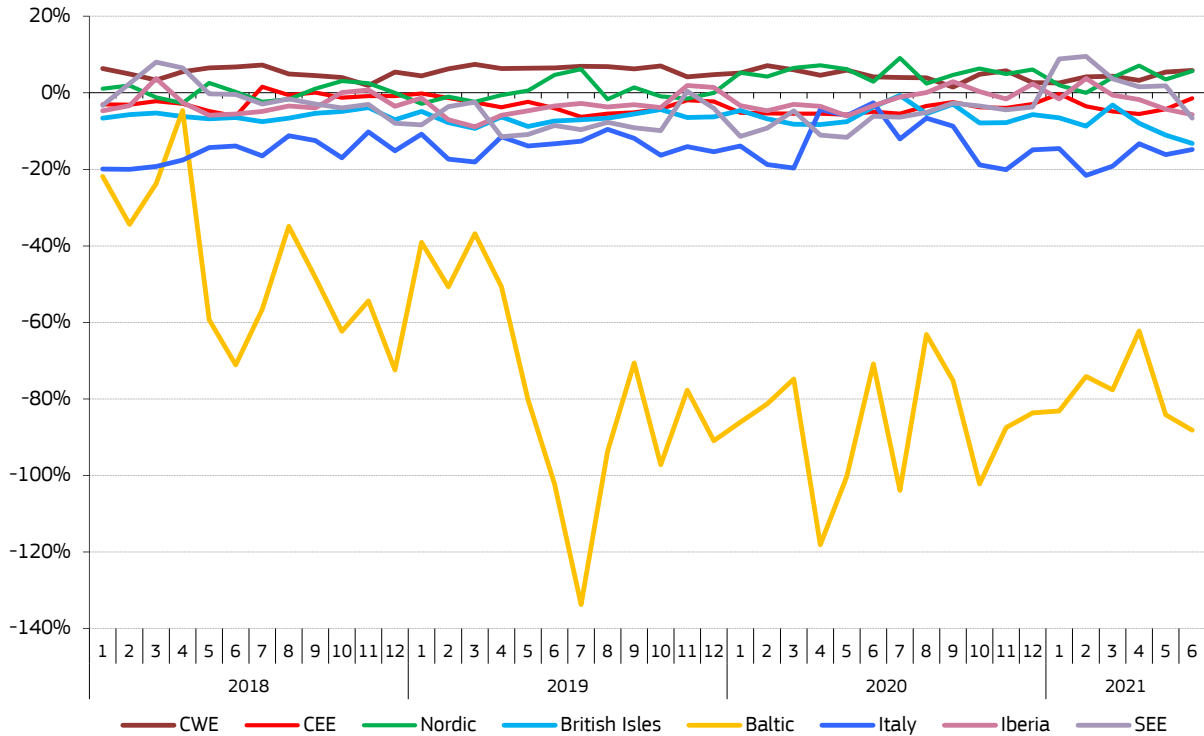
**Figure 24 – European cross-border monthly physical flows by region**



Source: ENTSO-E. Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, SK, SI, RO), Nordic (DK, SE, FI, NO), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, HR, RS, BA, ME, MK, AL), British Isles (UK, IE), Apennine Peninsula (IT, MT). Source: ENTSO-E, TSOs

- Figure 25** compares net cross border flows to regional power generation to give a better comparative perspective on the flows and their size. Positive values indicate a net exporter. The position of the Baltic region, which has the biggest deficit compared to the size of its power sector, remained largely unchanged in Q2 2021 compared to the same quarter a year ago. Net imports (3 TWh) reached about 78% of domestic generation. Italy became the second largest importer relative to its domestic generation (15%), followed by the British Isles (11%). For the rest of the regions, net imports (or exports) did not exceed 6% of domestic generation.

**Figure 25 – The ratio of the net electricity exporter position and the domestic generation in European regions**



Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation



### 3 Focus on the impact of high commodity prices and recovery demand in the electricity sector

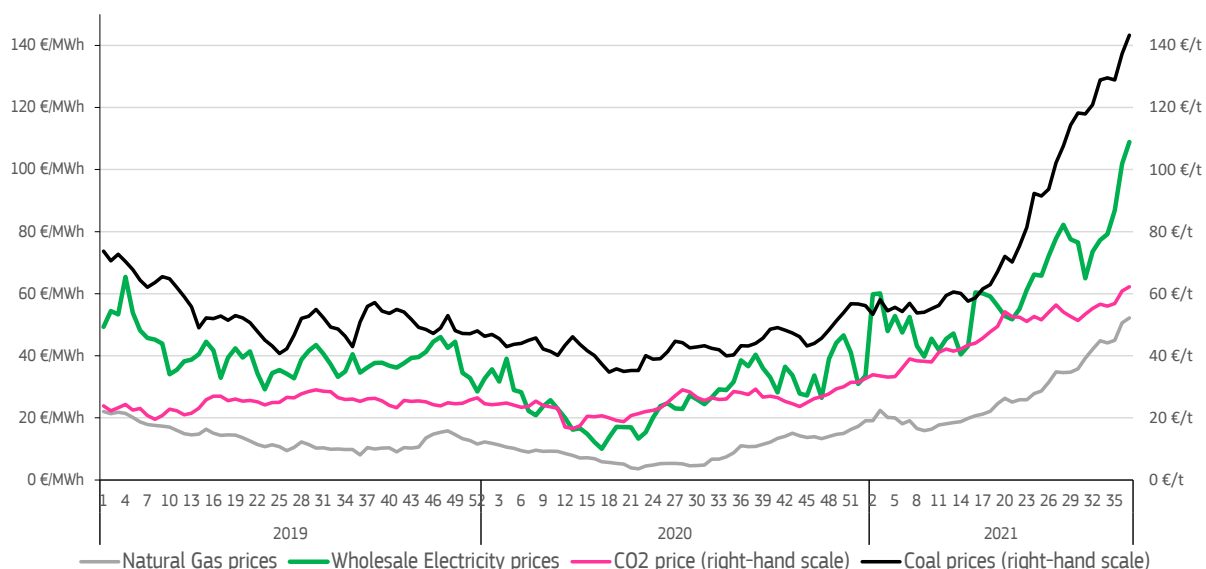
#### 3.1 Context of recent energy prices developments

- Wholesale energy prices have been rising significantly at a global scale, triggering considerable political and social concerns in an increasing number of Member States. The drivers of the price escalations are mainly of global nature. The significant increase in electricity prices in Europe over the last months can be explained mainly by an increase in global natural gas prices and to a lower extent, EU emissions allowances prices, in the context of a stronger global economic recovery, which has boosted demand for energy resources in comparison with 2020 levels. Market expectations on the evolution of energy commodities prices indicate that natural gas prices may remain high throughout the coming winter and possibly longer, depending on weather conditions. This situation has also triggered concerns about potential macroeconomic implications (e.g. inflation).
- Main concerns are driven by increases in retail energy prices in Member States. In the case of retail prices tied to dynamic pricing in their contracts (linking the increases of wholesale prices to retail in the short-term), the effects have been felt earlier (e.g. Spain). Other Member States where long-term contracting is more common (e.g. Germany) are likely to see retail prices increases in the upcoming months.
- Member States are already taking steps to mitigate the effects of rising energy prices, especially to reduce the impact on households' electricity bills. The European Commission recently worked on a toolbox for action, which includes a structured set of short and medium-term tools that could be used by Member States to alleviate the situation. The document will also provide suggestions to further expand the legislative package on Delivering the European Green Deal.

#### 3.2 Evolution of wholesale electricity prices

- **Figure 26** illustrates the overview of price developments of energy and commodity prices in Europe (electricity, gas, coal and CO2), which is closely interlinked to wholesale electricity prices (European Power Benchmark - EP5). With the first signs of strong economic recovery since the start of the pandemic in Europe, energy commodity and CO2 prices have been rising significantly. Wholesale electricity prices have also been following that trend, rising significantly over the last year with the slow but steady return to the pre-pandemic levels of economic activity.

**Figure 26 – Electricity and energy price commodities price development since 2019**

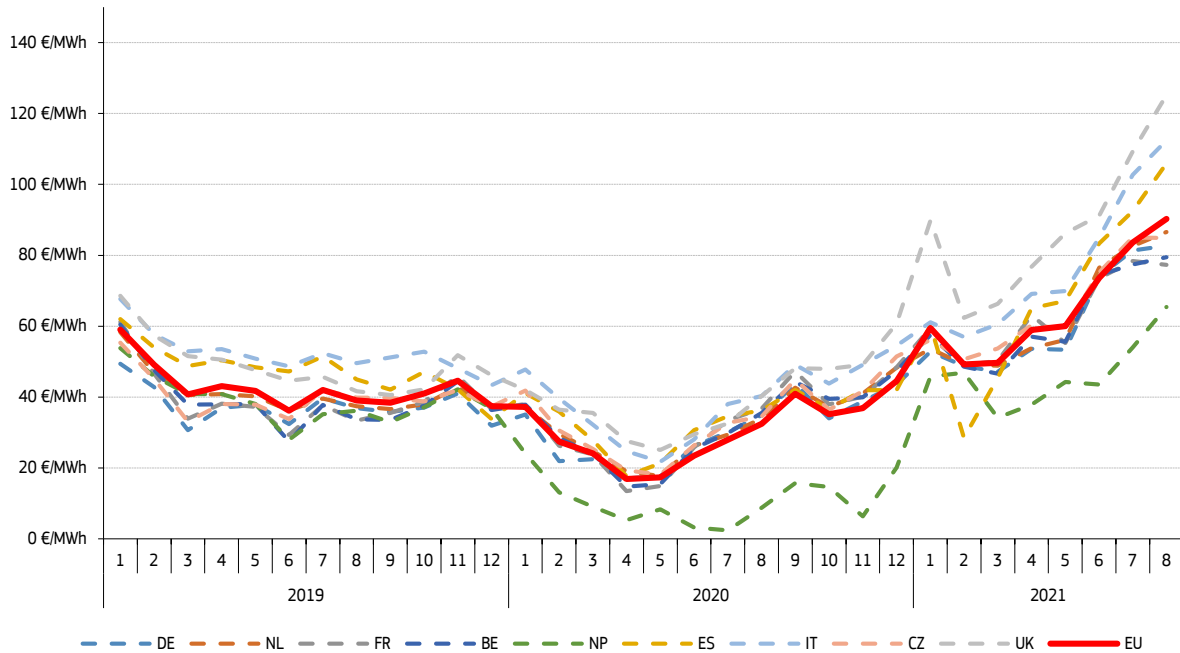


Source: Platts, European Power Exchanges, ENER

- **Figure 27** shows that the consumption-weighted benchmark (9) of nine markets (Germany, France, Netherlands, Belgium, Spain, Nord Pool, Italy, Czechia and the United Kingdom) averaged 90 EUR/MWh in August. This is more than a fivefold increase since the lowest recorded prices of the pandemic (May 2020) and a 178% rise year-on-year. The main driving force behind the rise are fuel/commodity prices, especially gas and to a lower extent, emission allowances. So far, European electricity prices of the first half of 2021 are on average 150% higher than in 2020 but only 28% higher than the average price of the first half of 2019. After setting several daily records above 150

EUR/MWh in September, electricity prices look poised to move even higher in the coming winter, as the rally in gas prices shows no sign of easing).

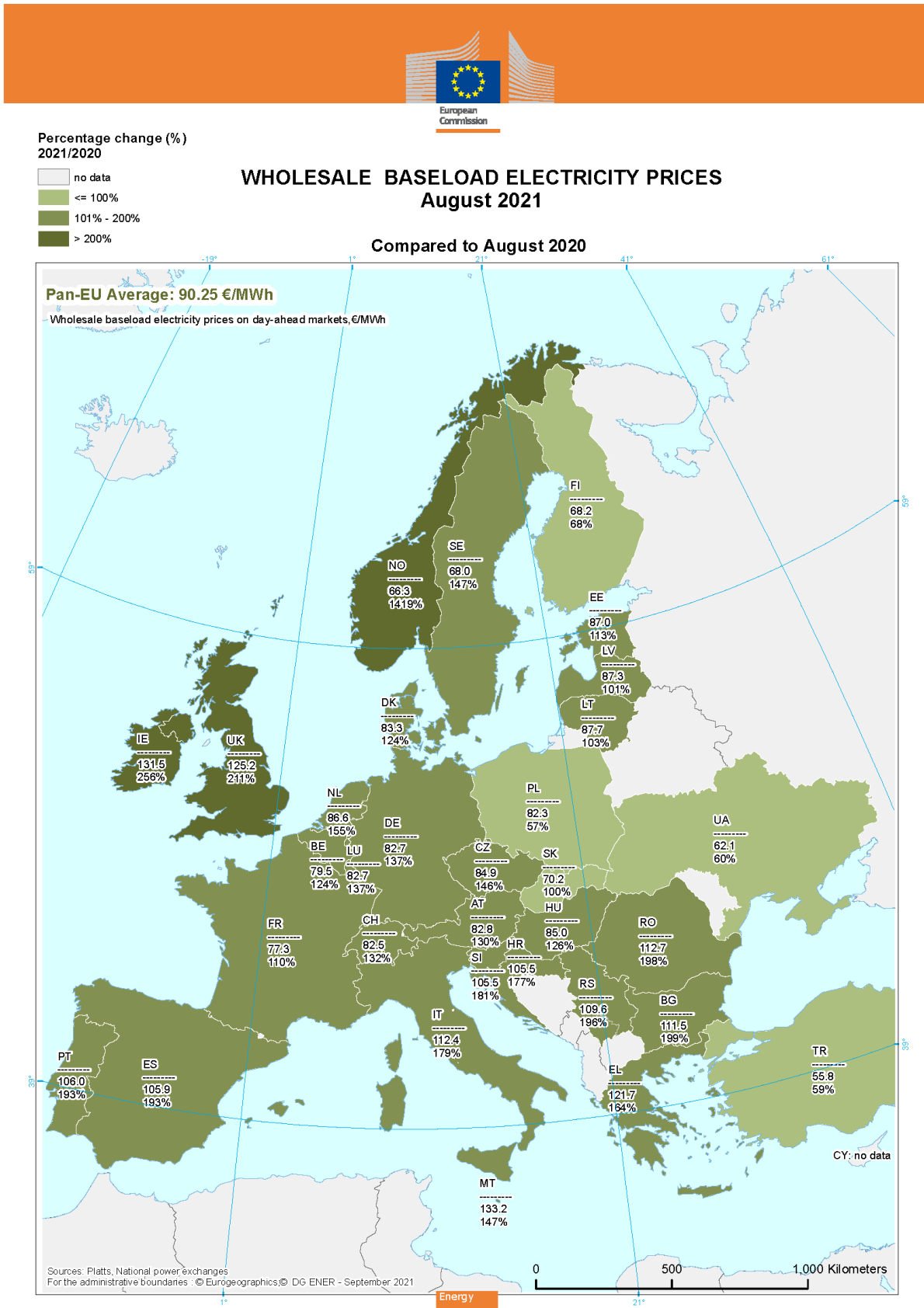
**Figure 27 - Evolution of wholesale electricity prices of nine European markets (2019-2021)**



Source: Platts, European power exchanges.

- As shown in **Figure 28**, during August, 25 Member States experienced yearly increases of wholesale electricity prices above 100% and some of them, close to or even over 200%, such as Ireland (+256%), Bulgaria (+199%), Spain (+193%), Portugal (+193%) and Slovenia (+181%). Increases below 100% were found in the Finnish prices, which rose by 68%, and Polish prices (+57% on yearly basis). In addition, wholesale electricity prices have increased 130% compared to August 2019 (Ireland +188%, Bulgaria +114%, Spain +136%, Portugal +136% and Slovenia +93%).

Figure 28 - Comparison of average wholesale baseload electricity prices, August 2021

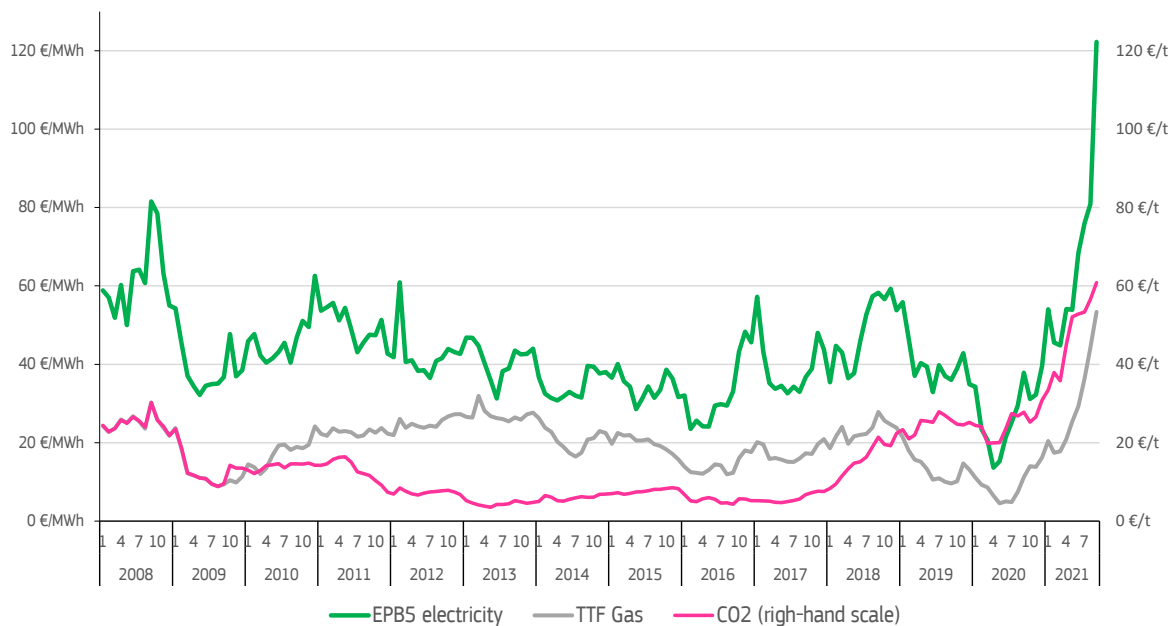


Source: European wholesale power exchanges, government agencies and intermediaries

### 3.3 Rising commodity prices

- **Figure 29** shows the historical evolution of electricity, gas and emissions allowances prices since 2008. Wholesale gas prices (Dutch Title Transfer Facility) also rose by more than 200% in Europe during 2021, reaching an all-time high average of 64 €/MWh in September. The rise in global gas demand is driven by increased demand in Asia, particularly China, which is making efforts to avoid security of supply issues for the coming winter after the cold spells of the last winter. Demand is also increasing in Japan, Korea, Taiwan and India. Brazil's demand for LNG also grew to counteract the effects of a drought-induced lack of hydro generation. High prices in Asia increase prices in Europe as LNG cargoes are redirected to these markets, leaving less supply for Europe. LNG production worldwide has been lower than expected as a result of unplanned outages, and delayed maintenance. Reduced volumes and more expensive LNG supply resulted from Qatar and Australia's lower output and high transport fees. Besides, Gazprom (Russian majority state-owned energy company and the largest supplier of natural gas to Europe) booked less annual and quarterly capacities than expected on the Ukrainian and Yamal infrastructure. The [IEA released a statement in September](#) where communicates that it *'believes Russia could do more to increase gas availability to Europe'* ahead of the winter season and that is also an opportunity for Russia to *'underscore its credential as a reliable supplier of the European market'*.
- Lower LNG inflows have resulted in a slower refill of gas storages in Europe. Unusually cold April and May, and earlier-than-usual maintenance works in Norway pipelines, depleted stocks this spring and delayed the start of a refill in most EU countries. In July a lower gas volume was shipped from Russia due the usual maintenance on the transit pipelines (Yamal, Nord Stream 1). However, significantly lower-than-usual volumes have been observed since, tightening the market as the heating season approaches. It is expected that imports from Norway and Russia will pick up with average levels after the end of the maintenance works. However, the new Nord Stream 2 is not going to play a role during this heating season as the [permission procedures might take several months of time](#). Current storage levels are at 71-72%, well below 90% seen in the last two years. The speed of filling up of storages before the winter heating season starts and weather conditions in the coming months, especially in Europe and Asia, will impact demand for LNG and can result in volatile gas prices.
- The rise in carbon prices, induced by the greater demand from coal-fired power plants which have regained the competitive edge and the expectation of tighter markets, has also aggravated the increase in electricity supply costs. The expectations of a tighter supply-demand balance respond to the recent EU climate policy commitments and the new European Climate Package (also called 'Fit for 55' package). Greater scarcity is expected in the years ahead. Already in 2021, the market is undersupplied. With the start of Phase IV of the EU ETS, the Market Stability Reserve is reducing the surplus of allowances while upcoming reforms to the EU ETS as part of the "Fit for 55" package are supporting a tighter market. Carbon prices have also increased due to the relative increase in demand for allowances triggered by a larger use of coal for producing electricity which is a consequence of higher gas prices. Carbon chases the price of gas as more expensive gas creates incentives for coal generation, thereby, increasing demand for CO<sub>2</sub> allowances. In August, carbon prices rose by 130% since 2020, and 70% since the start of 2021. The September average price has been reported at 61 €/tCO<sub>2</sub> so far, registering a daily peak of 63 €/tCO<sub>2</sub> on 9 September. The jump in prices is an important milestone, considering that only a few years ago, allowances were auctioned for 6 €/tCO<sub>2</sub>. Carbon prices impact the electricity sector mainly by affecting the profitability and investment prospects of various generation technologies and by extension, the pace of electricity decarbonisation.

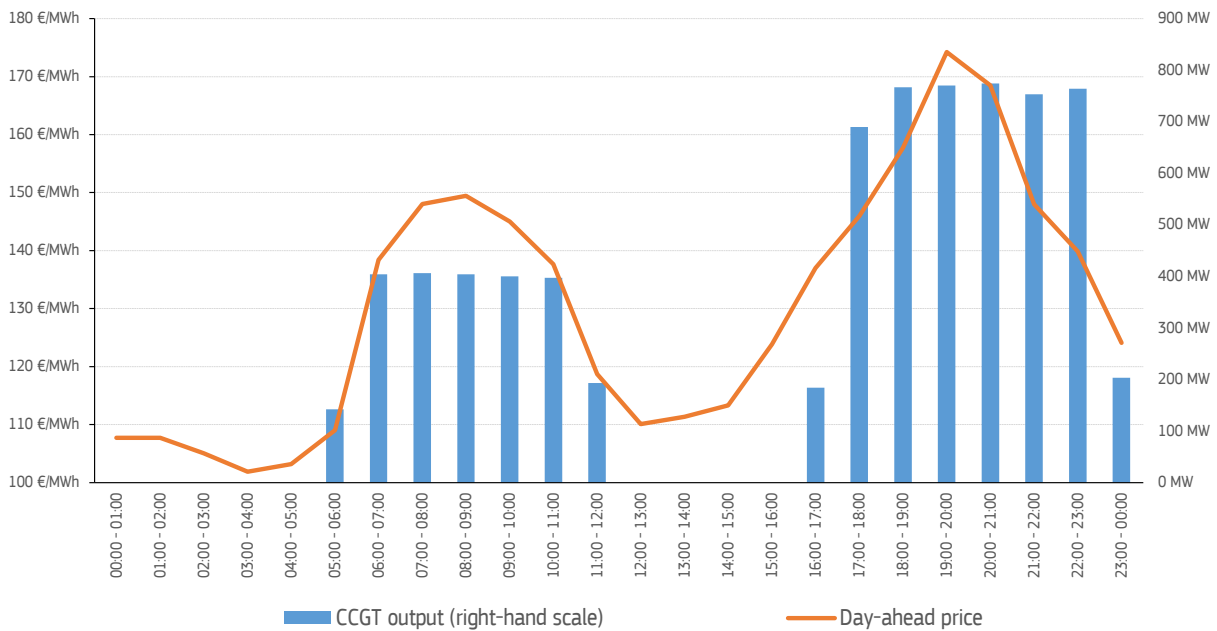
**Figure 29 – Historical evolution of the price of electricity, gas, and emissions allowances**



Source: Platts, European Power Exchanges, ENER

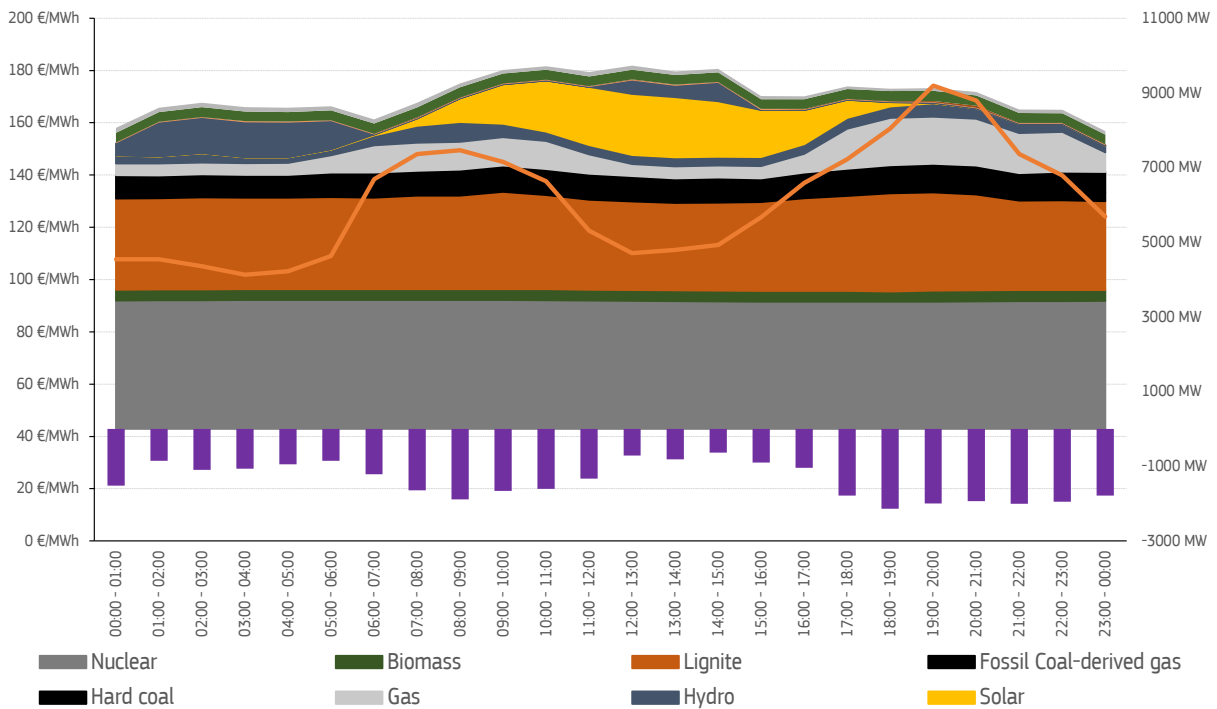
- The EU wholesale electricity market is driven by the merit order dynamics: power plants and other participants enter the market based on the order of their short run marginal costs, starting with the lowest and going until the last plant which is needed to meet consumers' demand is dispatched. This last plant (often a gas plant in peak times) is the one that sets the price for a particular period of time (typically an hour). Market integration plays a significant role in price formation too, as merit orders from neighbouring markets or bidding zones interact and influence one another, depending on the availability of interconnectors. The resulting set-up of prices reflects the most efficient use of available generation sources and designated interconnection capacities. To show this interplay in a simplified manner, **Figure 30** shows the interaction between a major gas-fired power plant operation and electricity prices during a given day in Czechia (CCGT 838 MW of capacity). It is also important to take into account other factors that could also be influencing prices during the reference day. **Figure 31** presents the generation technologies dispatched, net imports, total load and prices. It is possible to observe that around the middle of the day, solar PV plants generate the most and push electricity prices to relatively low levels, which are not high enough to induce the CCGT plant into action. High gas prices mean that the CCGT plant is called into action only during the morning and evening demand peaks when power prices are high enough to cover the plant's considerable operating costs. The evening peak is marked not so much by rising consumption, but by quickly waning solar generation which needs to be flexibly replaced by alternative sources. During the morning and evening peaks, net exports rise to other bidding zones (AT, DE, SK), as the market coupling mechanism determined that some of the output flexibility demanded in those zones could be efficiently provided by Czech generation sources.

**Figure 30 – The interaction between the operation of the largest CCGT in Czechia and day-ahead prices (9 September 2021)**



Source: ENTSOE

**Figure 31 – Day-ahead prices, generation, total load and net imports in Czechia (9 September 2021)**



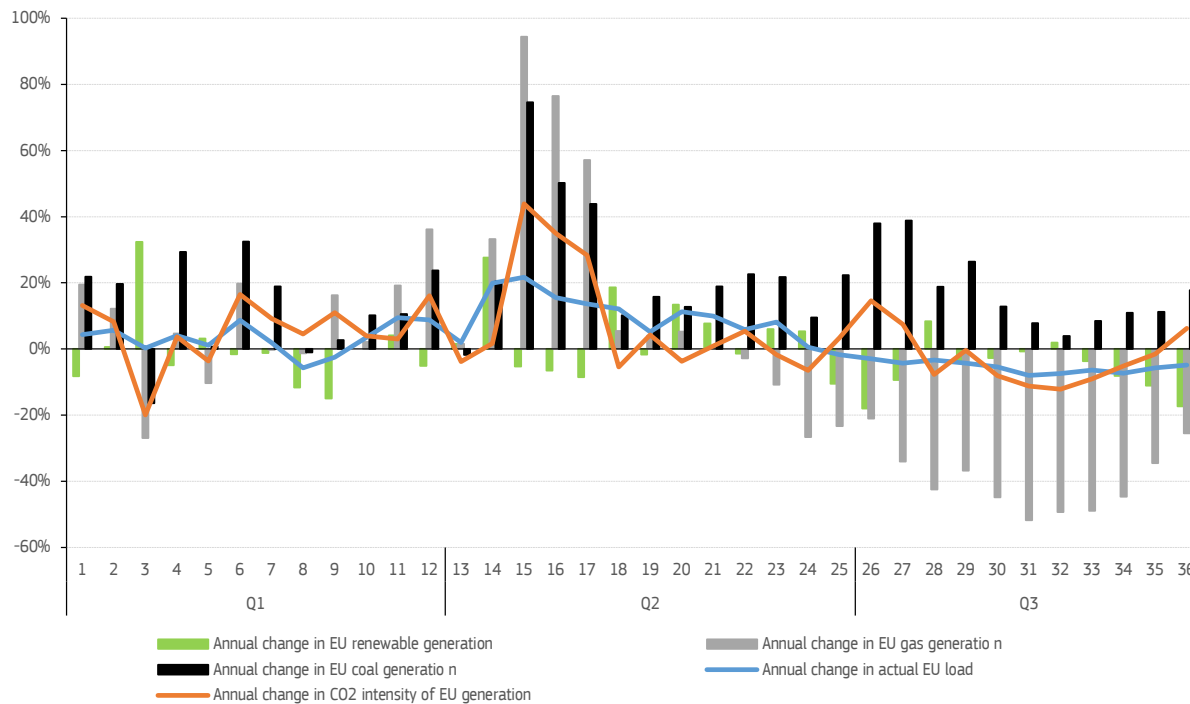
Source: ENTSOE

### 3.4 Power demand and activity.

- **Figure 32** shows changes in weekly actual load (a proxy for power demand), renewable, gas and coal generation and CO2 intensity of the European power mix between 2020 and 2021. During most of 2021, the carbon footprint of electricity generation was significantly higher than in the same period last year due to greater demand and

slightly lower renewable generation, both of which opened more space for fossil fuels in the merit order, increasing runtimes of coal- and gas-fired power plants. The surge in gas prices discouraged further gas-fired generation, leaving greater space for coal generation as can be observed during Q3 2021. For the whole Q2 2021, the power sector's CO2 emissions in the EU27 were estimated to increase by 19% compared to the same quarter a year before. As the current trend continued and even strengthened in July and August, the EU power sector is on track for an increase in carbon emissions in 2021, after a [10% annual drop in 2020](#). **Figure 32** also demonstrates that the spike in power demand was registered in April, when the start of vaccinations allowed easing some of the restrictions measures.

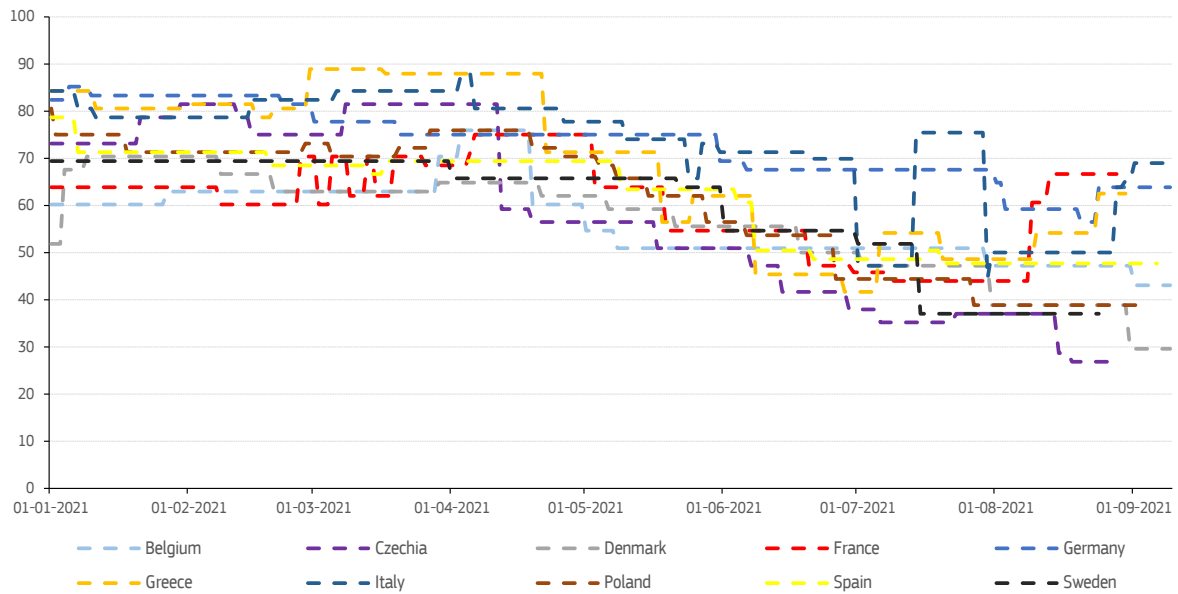
**Figure 32 – Weekly development of annual changes in actual load, renewable, gas and coal generation and CO2 intensity of the European power mix in 2021**



Source: ENTSO-E, Wartsila Energy Transition Lab. In addition to all EU27 Member States except Croatia, the data covers Norway, the UK, Switzerland, Bosnia and Herzegovina, Serbia, Montenegro, Albania and North Macedonia.

- In order to visualize the different government approaches towards the pandemic, a composite [measure](#) based on twenty-three response indicators including containment and closure policies (e.g. school closures and restrictions in movement), economic policies (such as income support to citizens or provision of foreign aid), health system policies (i.e. COVID-19 testing, emergency investments into healthcare system) and vaccine policies. The indicators are re-scaled to a value from 0 to 100, designed by Oxford University's Blavatnik School of Government. The index, reproduced in **Figure 33** for selected Member States, shows that the initial severity of restrictions from last year have been steadily falling since April. However, some countries have partially increased the stringency measures in response to new COVID variants.

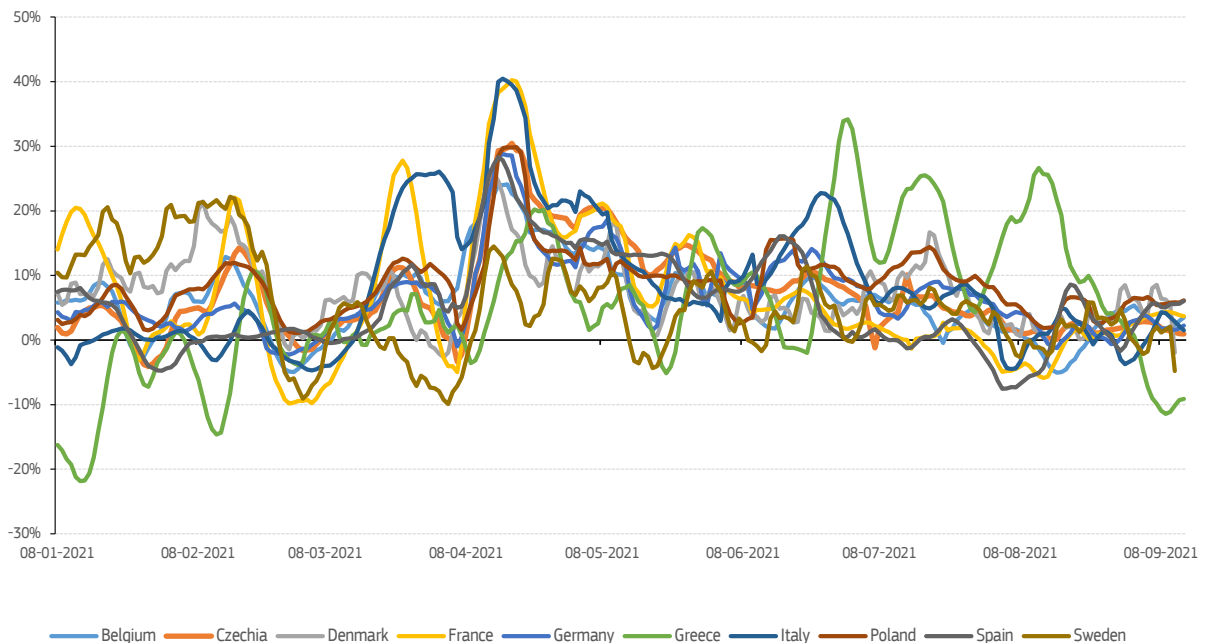
**Figure 33 – Government Response Stringency Index for selected Member States**



Source: Oxford COVID-19 Government Response Tracker

- Figure 34** illustrates changes in actual load in the same countries as in the previous figure between 2020 and 2021. It shows that power demand has been increasing in most of Member States, in line with the fall of the Government Stringency Index. April and May concentrated the largest increase in electricity demand during 2021. France experienced the largest increase in electricity consumption, reaching 40% at one point in the middle of April. In the beginning of July, Greek power demand increased 34% year-on-year. Sweden and Denmark, where restrictions on economic activity were less severe, experienced much more limited impacts on electricity consumption. **Figure 34** also points to a partial recovery in power demand in the weeks following the easing of lockdown measures (April) and the start of the vaccination roll out. In some cases, however, this recovery has proved to be unstable and prone to setbacks due to the appearance of new COVID variants.

**Figure 34 – Annual change in actual load in selected Member States – rolling 7-day average**



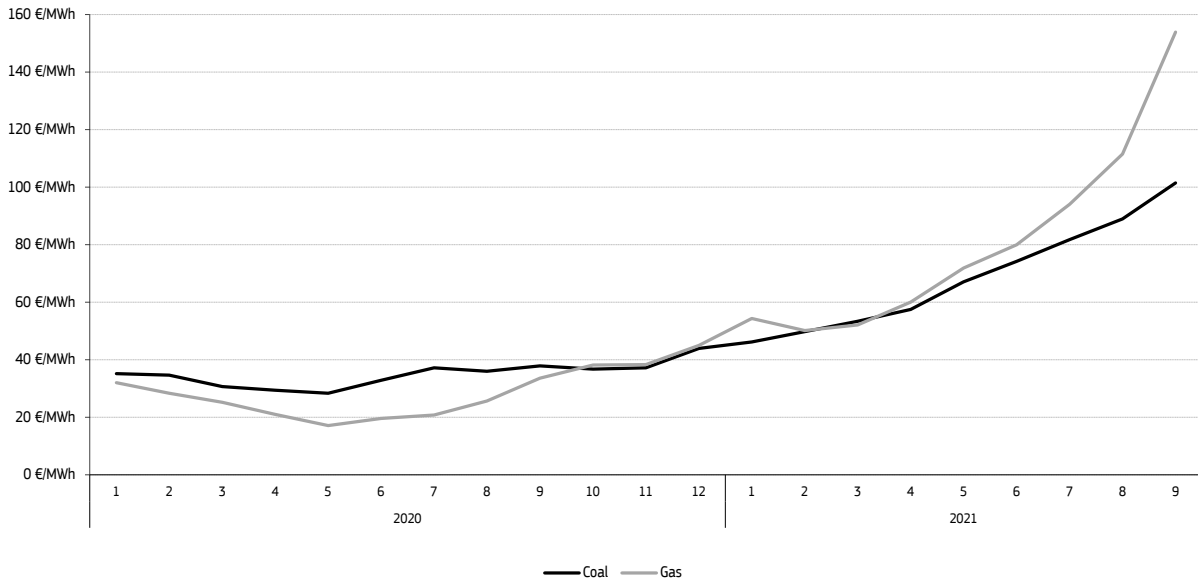
Source: ENTSO-E



### 3.5 Short and medium-term impacts

- Carbon and commodity prices influence wholesale electricity prices. The 30 €/tCO<sub>2</sub> increase in carbon prices during 2021, represents roughly a cost increase for a gas-fired power plant of around 10 €/MWh produced. Likewise, the same increase in carbon prices approximately translates into 25 €/MWh extra costs for a hard-coal power plant. This is clearly outweighed by the effect of roughly 45 €/MWh increase of gas prices, which represents a costs of increase of around € 90 per MWh produced, while the increase of almost 100 €/t of coal, adds roughly 30 € per MWh generated.
- Profitability of coal and gas power plants is determined, among other factors, by prices of fuels and the cost of emission allowances. Rising gas prices, for instance, can lead to a worsening of gas-fired power plants margins, in spite of record-high carbon prices, as can be observed during the current year, when high gas prices kept utilisation rates of gas-fired plants under pressure in Germany or the Netherlands.
- The significant rise in gas prices impacts prominently the electricity sector. Under normal conditions, the carbon price increase should have promoted fuel switching (from coal to gas). However, the recent rise in gas prices has had a more significant impact on gas-fired generation costs than the increase in coal and carbon prices on coal-fired generation costs, which negated incentives for fuel switching. Lignite-fired generation, which has higher emissions per generated unit but low fuel costs, managed to gain share in many European power mixes to the detriment of gas recently.
- As **Figure 35** shows, remarkable levels of coal-to-gas switching were reported in 2020, thanks to a combination of low gas prices and the increasing prices of emission allowances. Therefore, gas plants remained in a better commercial position compared with coal and lignite plants<sup>2</sup>. However, the trend reversed in 2021. Cold weather in January sustained increasing demand and high gas prices were reported to exceed the influence of carbon prices in coal generation. As such, coal and lignite generation returned to the profitability zone, leading to more coal-fired running time. While February and March reported better prospects for gas, the trend was reversed in the following months as a result of supply tightness in the gas market, making gas-fired generation more expensive than more polluting but cheaper to run coal-fired plants.

**Figure 35 – Generation costs of coal- and gas-fired power plants in Germany**



Source: Bloomberg, Platts, ENER

Note: Thermal efficiency values used are 50% and 41% for gas-fired and coal-fired generation respectively.

- **Figure 36** shows the changes in the levels of profitability of gas, coal and lignite-fired power plants in Germany. During 2021, coal and especially lignite generation have been retaking some of the lost ground during 2020. This

<sup>2</sup> It is to be noted that dispatching depends on more than just short run marginal costs. Other factors such as network availability, ramping times or maintenance schedules will also impact the dispatchability of a certain power plant.

dynamic, coupled with so far low wind speeds, has resulted in greater utilization of coal- and lignite-fired power plants during this year and in a potential increase in the power sector's carbon footprint compared to 2020.

- Since mid-February, clean dark and spark spreads have been in negative territory (with gas profitability holding a worse position than hard coal). The brown spread came back to profit after May 2021 and has remained positive on average since then. The main reason behind this trend are the short-run marginal costs of lignite which are comparably lower in the current environment of high coal and gas prices. Not even record-high CO<sub>2</sub> prices, which punish lignite the most of all technologies, can compensate for this. The clean spark spread is currently the lowest, sinking below zero since 2021.

**Figure 36 - Profitability of different generation technologies in Germany**



Source: ENTSO-E, Eurostat, Bloomberg, ENER

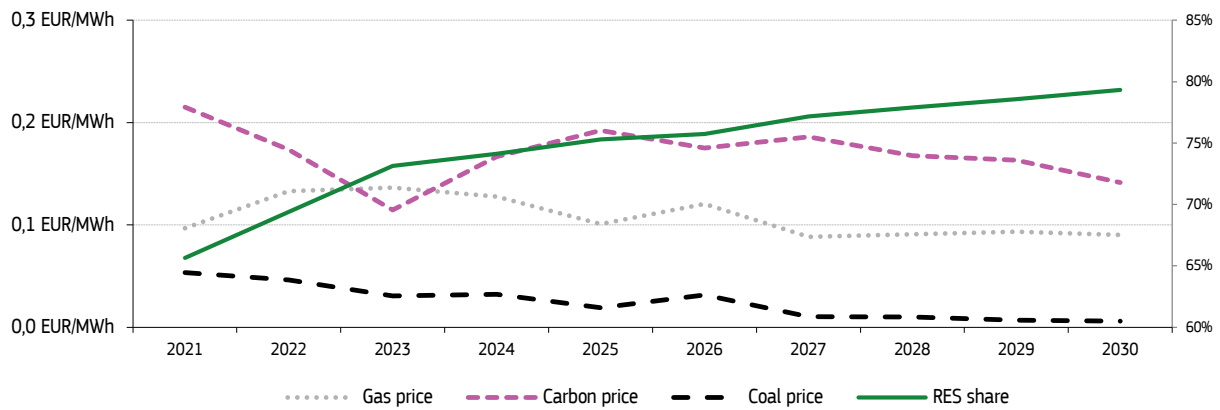
Note: spark spread refers to gas power plants, dark spread to coal power plants and brown spread to lignite power plants. Assumption of fixed cost of 6 EUR/MWh with 36.5% lignite plant efficiency

### 3.1 Long-term impacts

- In the long term, the effect of fossil fuels and carbon prices on wholesale electricity prices should gradually weaken. As the share of renewable capacity expands in the electricity generation mix, the effect of carbon and fuels over power prices will decrease.
- **Figure 38** presents the results of a sensitivity analysis of wholesale electricity to commodity prices<sup>3</sup> using the case of Germany. The results indicate that towards 2030, prices will decouple from commodities due to the growing share of renewable energy in the system (mainly wind and solar). By 2030, weather variability and not commodities, will become the main driver in power prices. As such, higher penetrations of renewables (wind and solar generation) would reduce the exposure of electricity prices to the variations in prices of commodities like coal and CO<sub>2</sub> prices. However, due to the replacement of lignite and coal, reliance on gas will tend to increase beyond 2030. However, due to the substitution of lignite and coal, reliance on gas will tend to increase beyond 2030. In 2022, a coal price increase of 1 €/t leads to an increase of 0.05 €/MWh in the German power price, whereas an increment of 1 €/tCO<sub>2</sub> results in a rise of 0.17 €/MWh in electricity prices and an increase of 1 €/MWh in gas pushes by 0.13 €/MWh the power price in Germany. In 2030, thanks to the significant increase of renewables in the power generation mix, the effect will be reduced to an increase of 0.01 €/MWh (coal), 0.14 €/MWh (carbon) and 0.09 €/MWh (gas).

<sup>3</sup> BloombergNEF. 2021 Germany Power Market Outlook.

**Figure 37 - Evolution of sensitivity of German power prices to commodities prices, carbon costs and share of renewables in power generation**



Source: BloombergNEF

- An increased share of renewables in the system, combined with other low carbon sources with low marginal costs, will make fossil fuels less significant in setting the wholesale market price. However, together with the uptake of renewables in the power system, it is important to further accelerate the implementation of interconnection projects, including Projects of Common Interests (PCI) and the effective use of interconnection capacity to increase competition. Higher interconnection levels will lead to greater price convergence and lower prices, especially in regions that are currently less well integrated. The support to the [evaluation of the TEN-E Regulation](#)<sup>4</sup> shows that already commissioned electricity interconnections as PCIs have contributed to price convergence with a clear downward impact on price levels on EU average at wholesale level. In particular, regions that are currently less interconnected, such as the Iberian Peninsula will benefit from this effect. On the demand side, increasing the energy efficiency efforts will help to diminish energy consumption and its impact on prices. Lower and more flexible demand combined with the deployment of smart meters and smart grids will allow to soften the times of peak demand through smart demand response measures to real time prices. Overall, a well-functioning and well-integrated EU energy market, continued investment in renewable technology and improvements in energy efficiency are key to keep prices at check for all consumers. This is the core of the Fit for 55 climate and energy package.

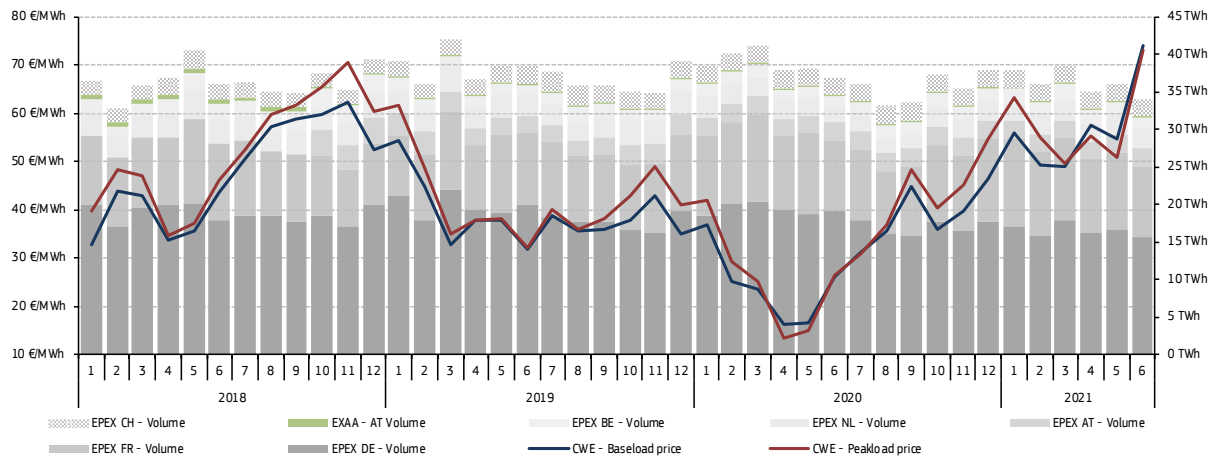
<sup>4</sup> Ecorys et. al. (2020): Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure, Final report.

## 4 Regional wholesale markets

### 4.1 Central Western Europe (Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland)

- In the second quarter of 2021, monthly average wholesale baseload electricity prices in Central Western Europe (CWE) have been rising. Following the rally in prices from last winter, the increase in spot prices has intensified, amid expensive gas, high CO<sub>2</sub> prices and growing power demand due to the relaunch of the economic activity. Wholesale electricity prices reached a peak in June (74 €/MWh), on the back of the previously mentioned factors combined with above-average temperatures in the region. Baseload electricity prices experienced a drop during May due to mild temperatures and increased renewable generation. The monthly average price for baseload power in June, reached 13-year highs, reflecting levels of demand close to pre-pandemic times. Compared to Q2 2020, the average baseload price in the region increased by 216% to 62 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 225% to 59 €/MWh. The rally of prices continued through the third quarter of the year, reaching historical highs throughout European countries.
- In France, following the delayed maintenance of the nuclear fleet which impacted availability during the last quarter, levels of nuclear generation improved considerably during the last month of Q2 2021, reporting gains of 30% year-on-year with summer availability back almost at 2019 levels. As a result, nuclear generation rose 13% year-on-year during Q2 2021. Low levels of wind during May, reduced hydro stocks reported at the lower end of the historical range and high demand, increased the space of fossil-based capacity in the system. Improved nuclear generation outweighed power demand in France, supporting significant rise in exports to neighbouring countries (except Italy) especially in May and June (on the back of increasing power demand in CWE).
- In Germany, despite records of solar generation in June, decreased levels of wind reduced the output of renewable generation. Against the backdrop of renewables and in the presence of improved power demand, hard coal and especially lignite generation, were called to meet the gap in demand, adding further running hours of thermal generation. Gas prices have impacted the German generation mix by lifting competitiveness of coal and lignite versus gas-fired generation. Net imports rose during the reference quarter, with inflows mainly from the Nordic region and France. More competitive Czech and Polish lignite and coal-fired generation has reduced exports from Germany to those countries. The Netherlands, experienced a 2% year-on-year increase in generation (+0.6 TWh) due to increased coal, biomass, wind and solar output, despite considerable decrease of gas and nuclear generation. Rather reduced levels of Alpine hydro generation in Austria were supported by increased gas and coal generation. Switzerland reported improved solar generation thanks to the record addition of 493 MW of new solar capacity during last year.
- Germany installed 1.4 GW of new solar capacity during Q2 2021. German government announced plans to extend solar power tender volume to 6 GW in 2022. In June, Berlin authorities announced that solar rooftops will be mandatory for new buildings from the year 2023.
- The Nordlink that connects Germany and Norway was officially commissioned on 27 May. The 625-km DC link has been operating since December 2020, with capacity restrictions mainly due to bottlenecks in Germany. In addition, the project to build a direct electricity link between Germany and the UK (1.4 GW), announced financial closing by September, while is currently foreseeing the start of commercial operation from 2025. Germany recently passed a new legislation to allow the private operation of interconnectors. In addition, the 700 km HDVC subsea cable linking Germany with the UK was included in the German grid requirement act as one of the seventy nine key infrastructure projects.
- The third compensation auction in Germany to close coal-fired plants was slightly undersubscribed. Eleven bids were offered for a total of 2.1 GW of capacity to be shut down. Berkamen A, Farge and Scholven, among other plants, were set to cease operations by 31 October. Likewise, three nuclear power reactors are to be retired from the German power grid this year as part of the nuclear phase-out program.

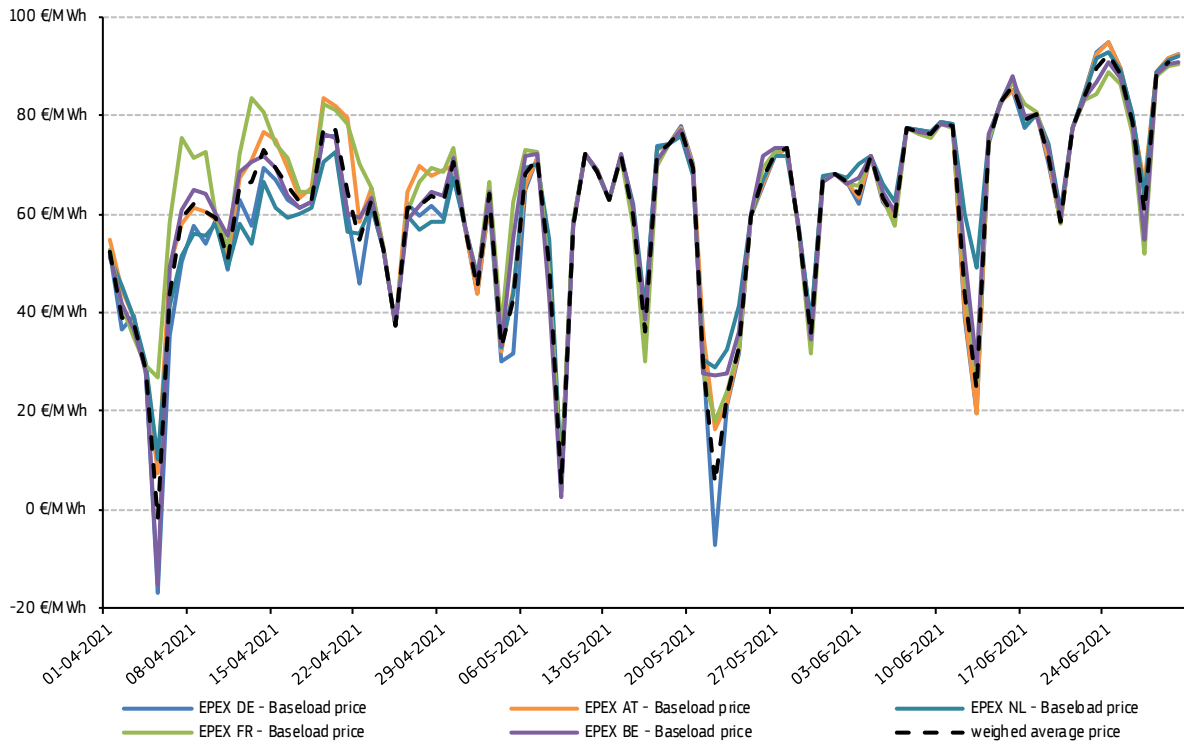
**Figure 38 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe**



Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- Figure 40** shows the daily average day-ahead prices in the region in the reference quarter. The second quarter of 2021, was marked by a sustained increase of prices. In April, daily average prices held mostly between 50 and 65 €/MWh. Volatility increased during May, driven by sharp variations of temperatures and wind generation, experiencing prices in the range of 40-70 €/MWh. Prices continued to rise during June registering prices between 65-85 €/MWh, due to high commodity prices and increased demand due to above-average temperatures. 13-year highs were registered over 90 €/MWh towards the end of the quarter. In particular, on 24 June, prices spiked to 92 €/MWh, due to peak prices of gas and emissions allowances, combined with reduced renewable generation.
- On the bottom side of the price spectrum, Germany, France and Belgium saw prices sinking below zero on April 5, owing to a surge in wind generation registered output record of 2.1 TWh in Europe, averaging at 87 GW during the day, covering 28% of the power demand in Europe, increased solar output and reduced power demand due to Easter Monday bank holiday. Renewable generation accounted for 74% of the share of total generation in Germany on that day.
- France exports followed the common trend of May and rose to an average of 7 GW month to date), from less than 2 GW registered up to April, on the back of decreased domestic demand, higher hydro output and the support of increased nuclear generation.

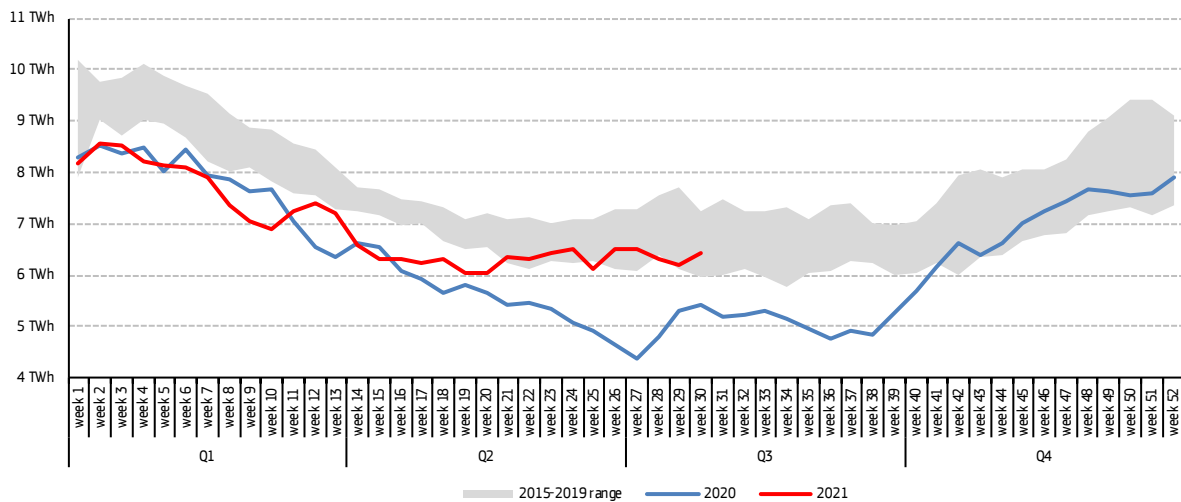
**Figure 39 – Daily average power prices on the day-ahead market in the CWE region**



Source: Platts.

- In May, French nuclear generation started to recover from the monthly lows of the previous quarter, as shown in **Figure 41**. French nuclear output was up 13% (9 TWh) year-on-year in Q2 2021. Nuclear generation hit a 10-month low on 9 May at 23 GW. Conversely, improved nuclear output peaked at 41 GW on 28 June, a recuperation of 11 GW on year. Nuclear generation met 87% of total domestic power demand in France during June, making a return to historical averages. Nuclear availability in July 2021 was at 45 GW, or the equivalent of 72% of installed capacity. French nuclear output fell in 2020 to a record-low of 335 TWh, mainly due to the economic recession, planned maintenance, closure of assets and extended outages. Due to the good performance in June, the 2021 estimated output was upgraded to the range of 345-365 TWh. Capacity improved due the return of Flamanville 1 and Paluel 2 in early May and Tricastin 3 and St Alban 2 in mid-May. Chooz 2 came back from extended maintenance (the reactor was online since December 2020) and Cattenom unit 3 from a 10-year overhaul at the end of August. In addition, Chooz 1 started planned maintenance in September, with unit 4 scheduled for such an overhaul in early 2022.

**Figure 40 – Weekly nuclear electricity generation in France**

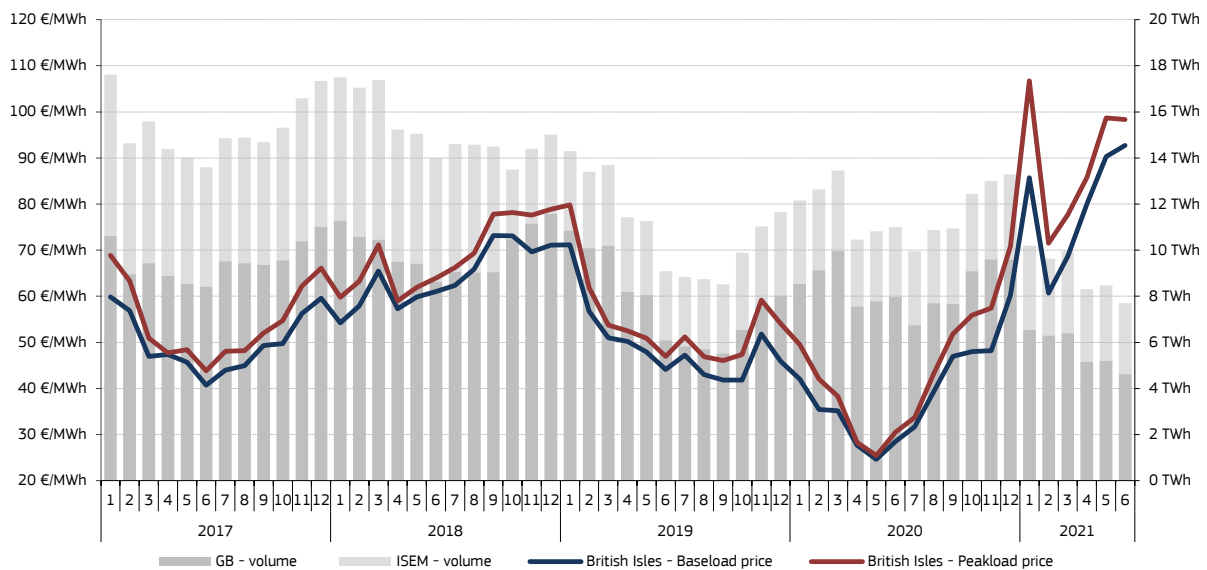


Source: ENTSO-E

#### 4.2 British Isles (GB, Ireland)

- Figure 42** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power rose again during Q2 2021, after the increases of January. The surge was driven mainly by high gas prices, combined with other factors, such as low wind availability, reduced nuclear output, robust demand and a tightening balance on the continent. Great Britain had insufficient spare capacity to meet the high power demand, resulting in coal and gas plants ramping up during the quarter to meet the increasing demand. Compared to Q2 2020, the average baseload price on the British Isles rose by 225% to 88 €/MWh during Q2 2021 and was 28% above the level from Q1 2021. Trading activity on the British day-ahead market decreased by 36% in Q2 2021 compared to the same quarter last year, whereas Ireland reported a 6% increase during the reference quarter. The UK power system was enhanced by two gas turbines (out of operation since 2018) in Scotland that were repurposed to provide inertia and reactive power, helping the grid to maintain steady frequency. Western HDVC link returned to operations in mid-March which helped to provide flexibility to the system. However, prices surged to historical levels during August and September, on the back of extreme gas prices and tight supply margins. Prices spiked in September amid low winds and an unplanned outage that affected the 2GW capacity IFA 1 cable infrastructure. The National Grid estimates the link will be out of service, at least, until mid-October.
- In July, the National Grid released an [early outlook](#) to reflect on envisaged winter margins. System margins are expected to be similar or slightly lower than the last winter. On the supply side, both Dungeness B and Hunterston B nuclear power plants and Baglan Bay, Severn Power and Sutton Bridge CCGTs power plants are expected to be offline in the coming winter. However, the IFA2 cable with France and the 1.4 GW NSL link with Norway are expected to be online from Q4 2021 (although the latter at the reduced capacity of 700 MW).

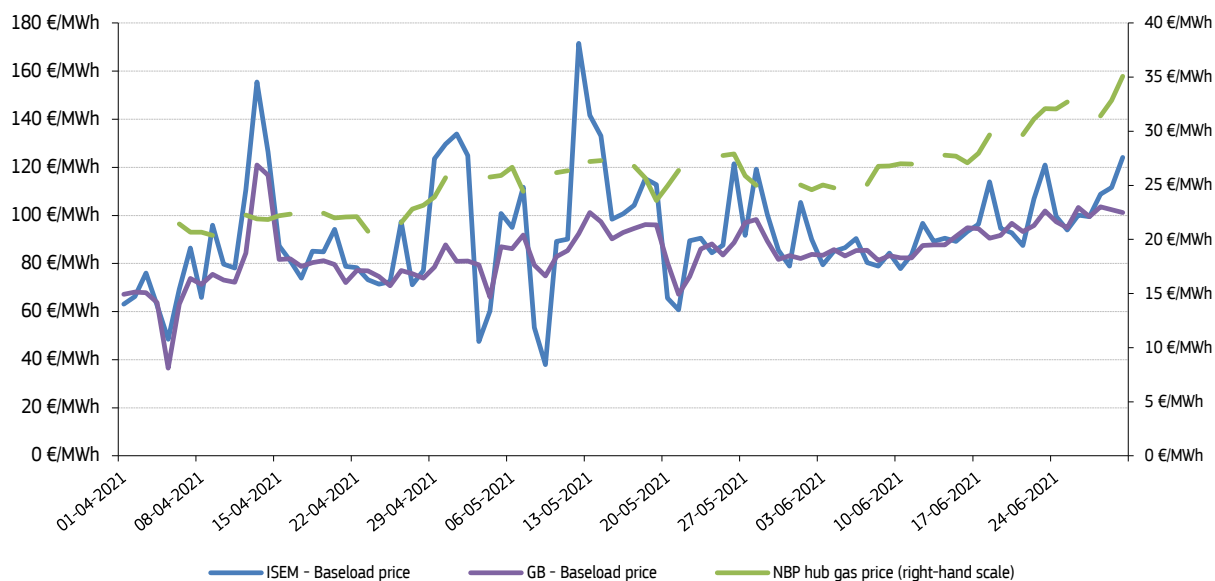
**Figure 41 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland**



Source: Nord Pool N2EX, SEMO, Utility Regulator

- Figure 43** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices hit the highest levels since early March (121 €/MWh) in April, on the back of high demand due to cold weather, low wind generation and tight margins of spare electricity capacity. Prices fluctuated among 75-95 €/MWh during the rest of the quarter, climbing due to supply tightness and a surge in gas prices. The Irish market registered spikes on 12 May, on the back of low winds, high power demand, displaying an average value of 150 €/MWh and reaching 300 €/MWh during peak times in the morning. Prices in the all-island Irish market generally followed the UK contract, albeit larger volatility due to fluctuation in wind generation. Low winds contributed to an 11% year-on-year output decline during the quarter, while coal generation saw an increase in its output by 390%, amid high gas prices which reduced gas-fired generation by 12% on yearly basis.

**Figure 42 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland**

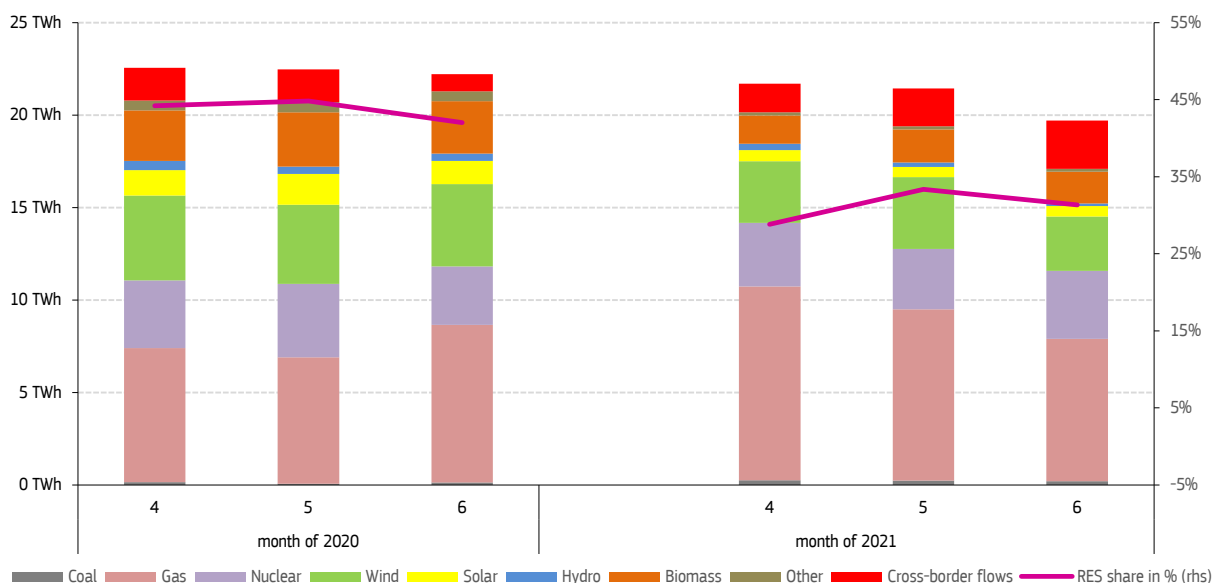


Source: Nord Pool NZEX, SEMO

- Figure 44** shows that coal and gas were the main winners of generation mix during Q2 2021, as both were required to fill the gap due to low wind generation (especially during June). Imports from the continent increased by 40% on a net basis. Coal-fired output increased significantly (98%) to cover the gap in demand of low winds. However, in absolute terms, its contribution was almost negligible compared with gas. Coal is now mainly used to cover demand peaks at times of low renewable availability and should leave the mix by 2024. Despite high gas prices at the NBP, gas-fired output increased by 21%. Biomass output registered a decline of 33% during the quarter. The renewable share decreased to 31%, up from 49% in the reference quarter during 2020, as June saw an important wind lull. Conversely, fossil fuels covered 51% of the total electricity generation, compared with 31% registered during Q2 2020.
- The early closure of nuclear reactors Hunterston B and Hinkley Point B by mid-2022, combined with the closure of Dungeness B nuclear power plant (1 GW) will remove nuclear installed capacity by two thirds by the end of 2022 (6 GW will remain). All existing UK reactors are schedule to shut down by the end of 2031, with the exception of Sizewell B, which should be in operation until 2055. Moreover, on 30 June, the UK government announced to bring forward the exit date for coal generation to October 2024. Ratcliffe power plant will be the last remaining unit from September 2022. The recent resurgence of coal generation in the UK has been fuelled by the surge in gas prices. However, it is expected that by 2023, coal generation will be consistently not profitable. Considering the nuclear and coal phase-out, the UK would become more reliant on electricity imports and flexible use of capacity to meet demand.
- Great Britain has 5 GW of interconnection capacity to other Member States (France, Belgium and the Netherlands). The North Sea Link to Norway (1.4 GW) is expected to come online during Q4 2021 together with the 1 GW cable to France. The Viking link to Denmark (1.4 GW) should further increase interconnectivity between the UK and the continent in 2023. In addition, another 1.4 GW power cable is due to be built in 2023-2024, connecting the Isle of Grain in the UK with Wilhemshaven in Germany. The UK government plans to become a net exporter of electricity by 2040 as opposed to the current net importer position. The Department of Business, Energy and Industrial Strategy (BEIS) [foresees an increase of the country's current capacity to almost 19 GW by 2040](#). The surplus electricity is expected to come from more than 20 GW of wind capacity (mainly offshore) during the same period.



**Figure 43 – Changes in the UK electricity mix between Q2 2020 and Q2 2021**

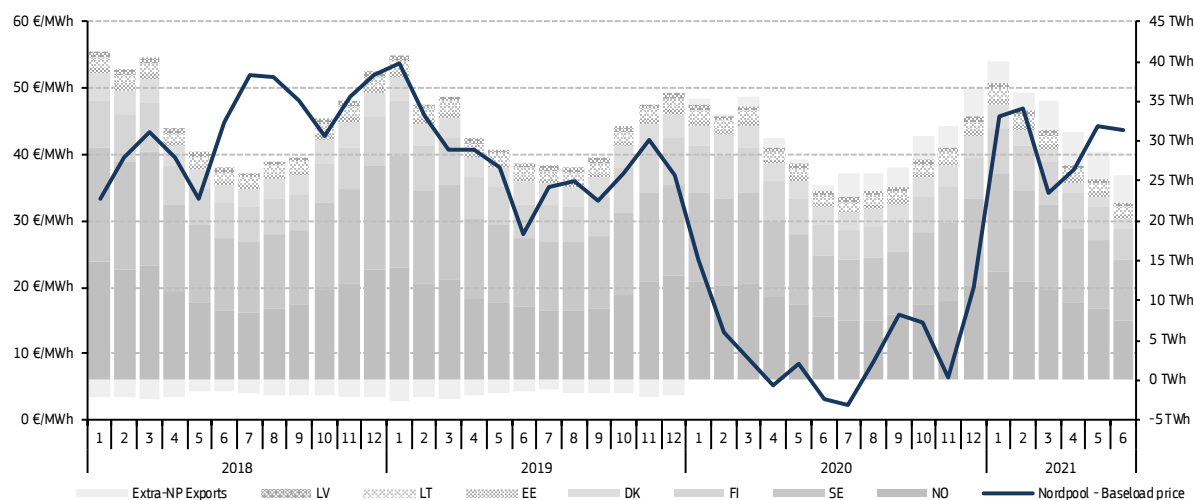


Source: BEIS

### 4.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway)

- As shown in **Figure 45**, Nord Pool prices rose again during a significant part of the second quarter of 2021, from the peaks during the winter. Spot prices rose during April on the back of cold and calm weather. Baseload prices continued to rise until May, reaching 44 €/MWh on the back of high power demand due to sustained cold weather, low wind speeds and a steep rundown in hydro reservoir stocks. Prices fell slightly thanks to the mild weather in June. Compared to Q2 2020, the average system baseload price surged by 650% to 42 €/MWh in the reference quarter. Extremely low prices in the second quarter of 2020 helped to amplify the increasing effect of prices during the reference quarter. Trading activity was 3% higher compared to the previous Q2.
- A new 400 kV power link between Sweden and Finland is on track to boost interconnection capacity by 65% between the two countries in 2025. The 380-km cable from Lapland in Sweden to the Finnish Baltic shore is expected to start the construction in 2024. The link will allow to balance the grid taking advantage of Swedish and Finnish enhanced wind capacity. Sweden is on track to exceed 17 GW of wind capacity by 2024, whereas Finland's wind sector is growing thanks to 6 GW of projects fully permitted. Finland is a net importer of electricity, amid delays of Olkiluoto-3 nuclear power plant, which is due to begin commercial operation in February 2022. In June, the Finnish nuclear reactor Olkiluoto-2 came back online improving levels of nuclear output.

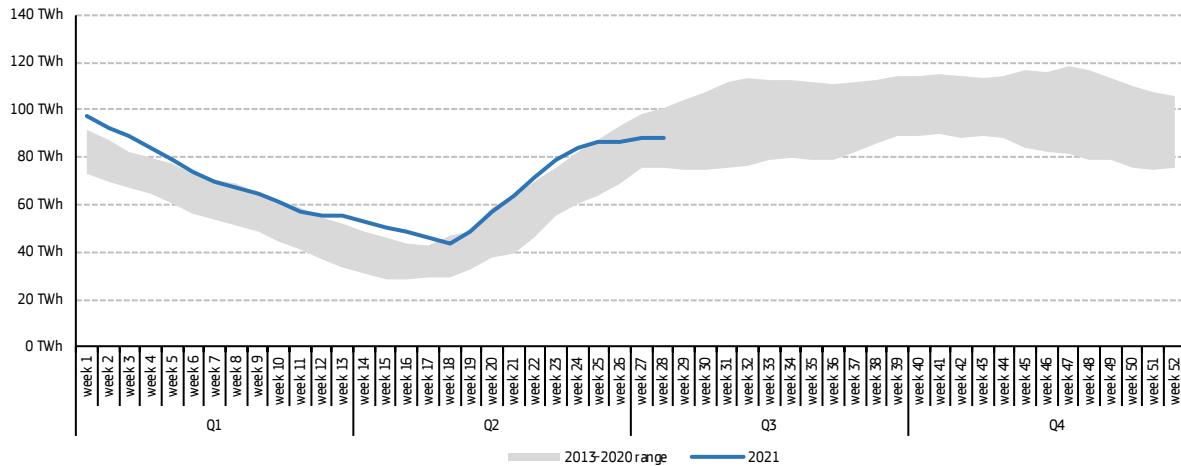
**Figure 44 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe**



Source: Nord Pool spot market

- Figure 46** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2021 compared to previous eight years. Hydroelectric stocks fell steadily during the first part of the quarter, on the back of cold weather and rising spot prices in the region. Hydro stocks rose again thanks to seasonal snow melt, in particular, between weeks 20 and 23. Week 24 saw stock climbing below 5 TWh for the first time since week 19. Despite falls during the first weeks of the quarter, hydro stock still held on the top tier for most of Q2 2021. In June, temperatures rose contributing to a fall in energy demand and snowmelt, registering the highest level of exports seen during 2021, thanks to low winds on the continent. Overall hydro generation in the region registered a decline during Q2 2021, driven by Sweden's 6% decrease (- 1.1 TWh), which could not be compensated by Norway's 2% year-on-year upturn (+ 0.6 TWh) and Finland's 7% gains (+ 0.3 TWh).

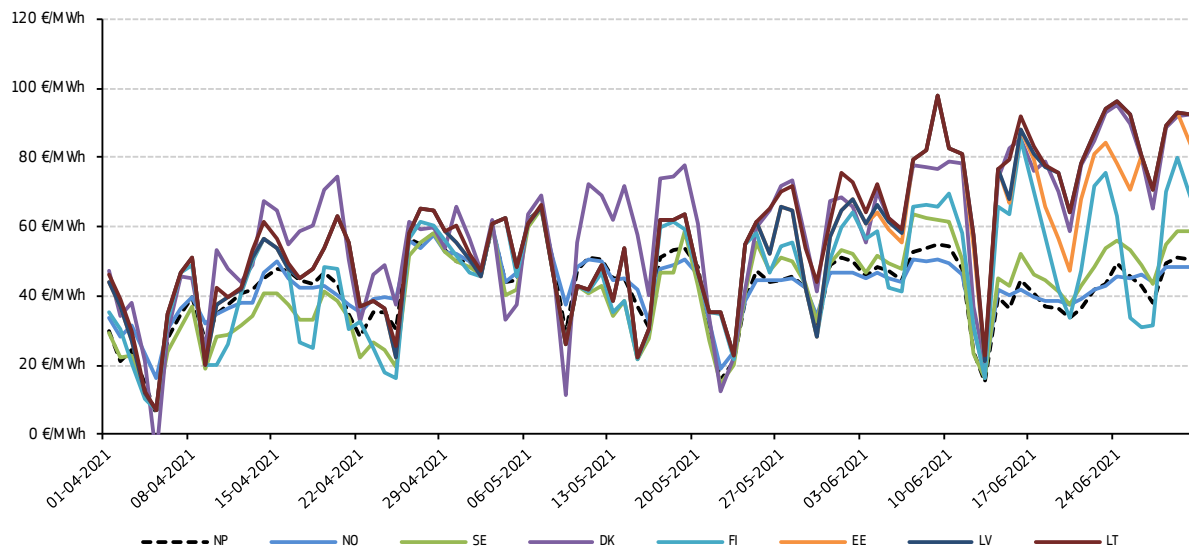
**Figure 45 – Nordic hydro reservoir levels in 2021, compared to the range of 2013-2020**



Source: Nord Pool spot market

- Figure 47** shows that average daily prices across Northern Europe continued to display a high degree of divergence, especially during the last months of Q2 2021. Continued cold weather caused electricity demand to hit record highs in the Nord Pool system on 7 May (65 €/MWh). Increased electrification of industry, transportation, and home energy use has boosted energy demand in the region, especially during cold periods. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 25**), registered nearly permanent premiums over the system contract. The Nordic region was affected by cooler temperatures in the first part of the quarter and also fell the impact of high fuel prices, which increased system prices during the second half of Q2 2021.

**Figure 46 – Daily average regional prices and the system price on the day-ahead market in the Nordic region**

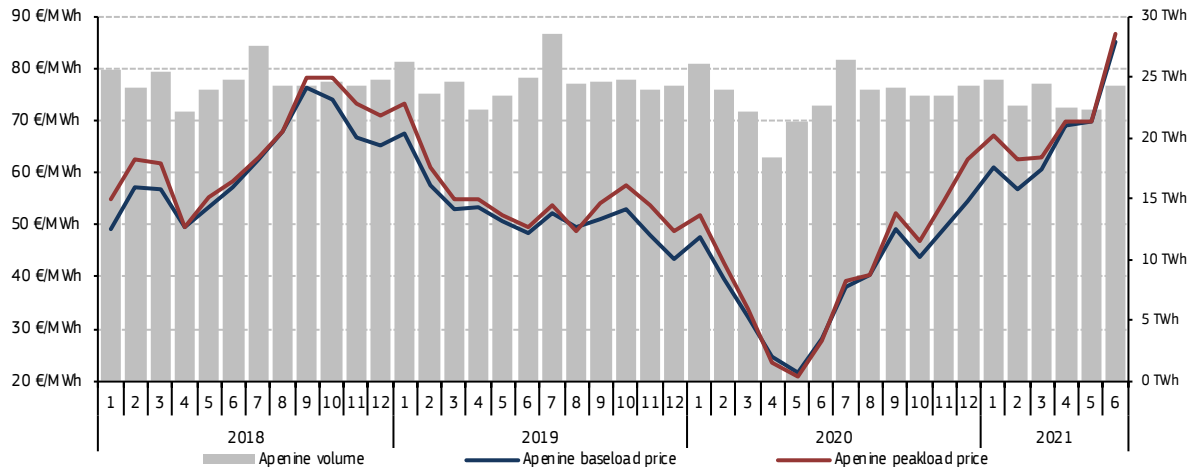


Source: Nord Pool spot market

#### 4.4 Apennine Peninsula (Italy, Malta)

- Rising Italian monthly average baseload electricity prices (**Figure 48**) reached a peak in June (85 €/MWh), registering the highest level since 2008, driven mainly by rising gas and emission allowances prices. The Italian market recorded one of the largest increases in Europe. The average baseload price in Q2 2021 rose by 25% compared to Q1 2021 to 75 €/MWh, and was 201% above Q2 2020 levels. Trading volumes increased by 11% compared to the previous Q2. The rally of prices continued through the following months, registering prices over 150 €/MWh during September in the Apennine Peninsula.

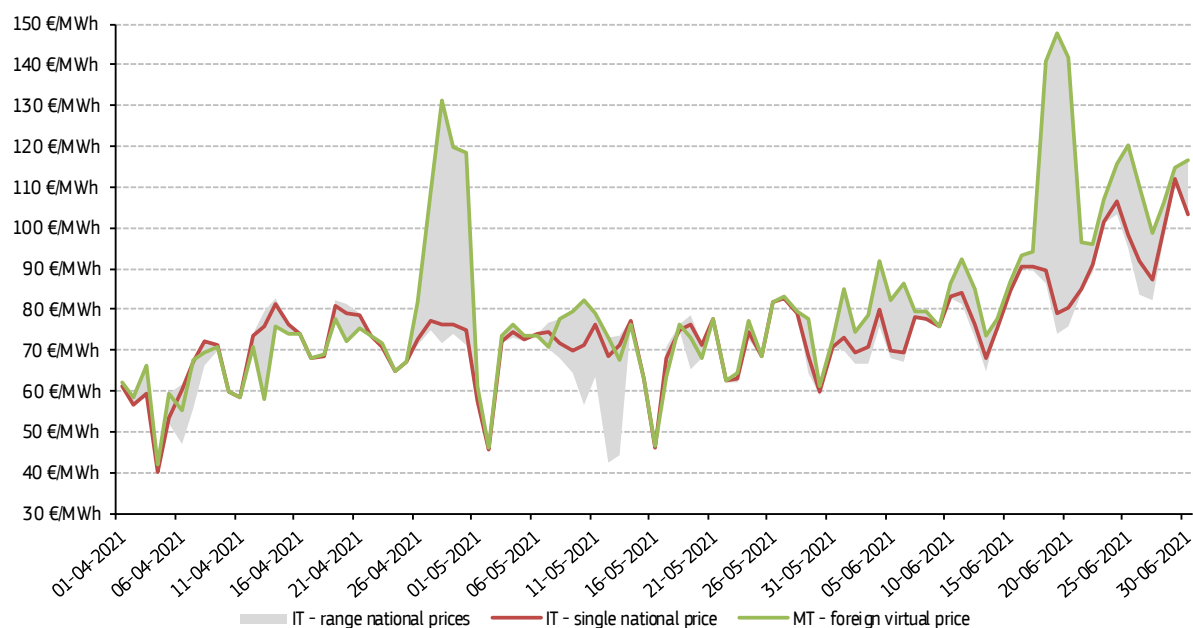
**Figure 47 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy**



Source: GME (IPEX)

- **Figure 49** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The national average stayed mostly between 60 and 75 €/MWh during April and May. In June, the prices moved above in the range of 75-90 €/MWh and kept rising during the following months.
- Italy is one of the largest producers of electricity from gas in the EU (gas represented 48% of the total generation in Italy during Q2 2021). Rising commodity prices, especially gas, played an important role in the surge in prices, in the context of continent-wide supply tightness (see **Figure 40**). Italian spot prices surged in June, as record gas and carbon prices kept wholesale prices high, as the easing of lockdown restrictions and hot weather boosted consumption, supported by a fall of wind and solar output year-on-year. As a result, net power imports increased to close the demand gap. Combined wind and solar output decreased in June. Thermal generation and imports from the northern borders were able to offset losses in renewable generation. In addition, multiple blackouts were reported in Milan during the last week of the month. The outage of the Greek-Italy interconnector during June was counterbalanced by the rise of net imports that averaged 4.9GW during the same month.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange (especially the Sicilian price zone) influence the Maltese wholesale electricity market. As visible in **Figure 49**, prices in the Maltese zone mostly formed the upper boundary of the band of regional prices in the reference period with a few exceptions in April.

**Figure 48 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices**

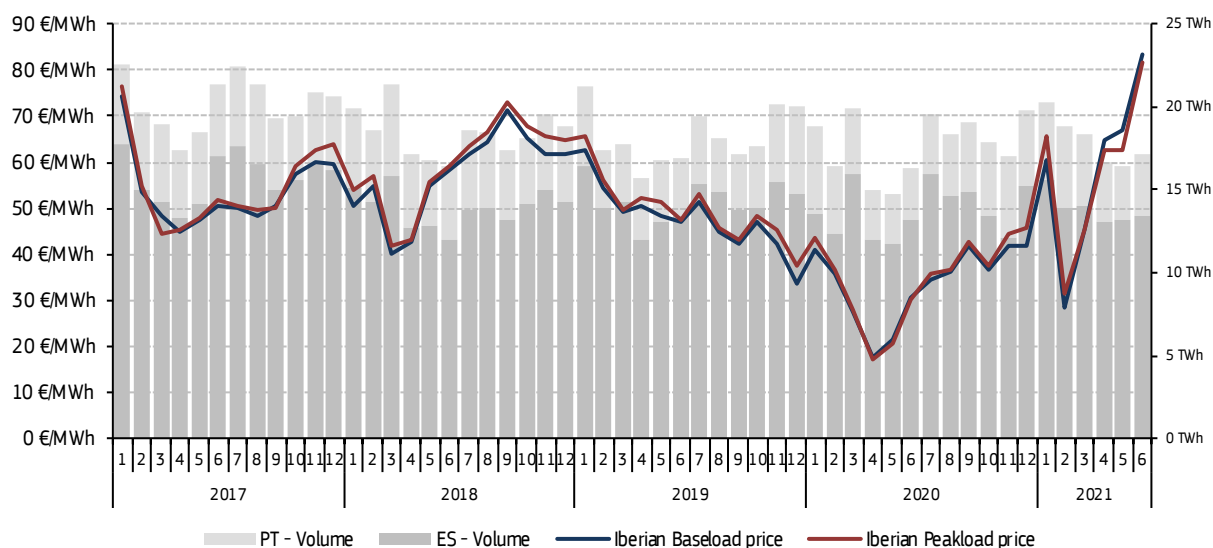


Source: GME (IPEX)

#### 4.5 Iberian Peninsula (Spain and Portugal)

- Figure 50** reports on monthly average baseload and peakload contracts in Spain and Portugal. During the second quarter of 2021, prices started reported a rising trend, mainly driven by gas and CO<sub>2</sub> prices. The average baseload electricity prices surged to 65 €/MWh in April and only rose slightly in May to 67 €/MWh, thanks to improved wind and solar generation, which reduced thermal generation. However, in June, prices spiked to 83 €/MWh, due to lower hydro output and increasing thermal generation. During the month, power imports from France played a key role thanks to improved French nuclear availability. Compared to Q2 2020, the average baseload price rose by 210% to 72 €/MWh in the reference quarter. Peak prices increased by 204% to 69 €/MWh. Trading activity was 8% higher compared to the previous Q2.
- Due to the rising power prices, Spain cut the electricity tax rate for consumers from 21 to 10% and announced several other measures, such as the suspension of the 7% generation tax for the third quarter of the year. In light of the surges in wholesale prices that took place during Q3 2021, the Government announced a full package of measures that will seek to tackle the social and economic effects of rising energy prices.

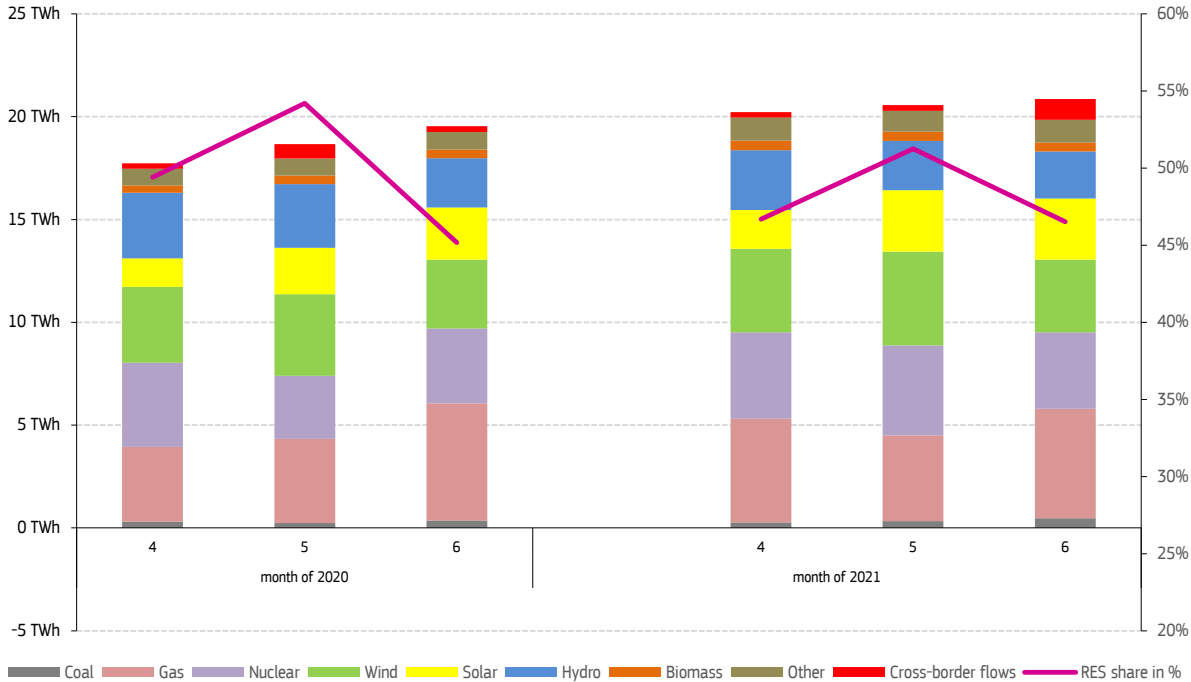
**Figure 49 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula**



Source: Platts, OMEL, DGEG

- Figure 51** displays the evolution of the monthly electricity generation mix in Spain during the second quarter of 2021, as well as during the same period of the previous year. Net generation increased by 10% year-on-year, in line with a surge in consumption. Rising solar and wind generation caused the share of renewable electricity sources to reach 48% during the reference quarter, slightly down from 50% a year before. Wind and solar generation rose by 10% and 27% respectively. Thanks to the increasing demand, gas generation rose by 8% and coal output increased by 18% year-on-year in Q2 2021. Nuclear generation rose by 14% during Q2 2021, and covered a share of 20% of the total generation, same level as the previous year. Spain net imports rose by 25%, with a considerable amount registered during June.
- The Spanish government approved the environmental impact of Navaleo (550 MW) hydro-pump Project of Common Interest, which could become online by 2023, providing fast time response to activate frequency containment measures and support to maintain instantaneous supply and demand balance. Spain sees almost 7 GW of pumping capacity in place by 2030. In addition, Spain published a road map for offshore wind targeting at 3 GW of capacity by 2030 and up to 60 MW on experimental marine energy projects.
- Spain authorities gave green light to the closure of Los Barrios coal-fired plant (570 MW), leaving only five coal-fired plants operating in the country. Only two units are expected to remain by the end of 2021: two units in the Balearic Islands and Abono power plant, which is integrated with steel manufacturing facilities. The rest of the fleet is scheduled to close during this year. The country authorities also approved the extension of the largest nuclear reactor in Spain (Cofrentes – 1.1 GW) until 2030, year in which it will cease operations. Between 2025 and 2030 the nuclear plants of Almaraz, Asco I and Cofrentes are scheduled to shut down, leaving Asco II, Vandellos and Trillo which will close between 2030 and 2035.
- Gas-fired generation increased by 18% (+ 0.5 TWh) in Portugal during the reference quarter, replacing the falling hydro which registered a 16% year-on-year decline (- 0.5 TWh).

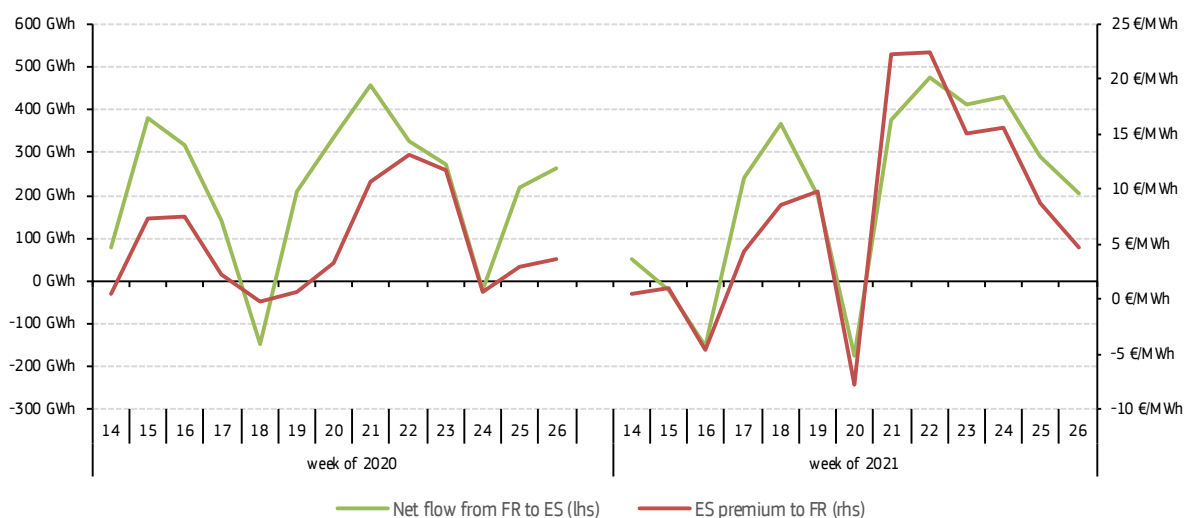
**Figure 50 – Monthly evolution of the electricity generation mix in Spain in Q2 of 2020 and 2021**



Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

- Figure 52** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. With the exception of a significant amount of time in April and a week in May, Spain kept its usual premium over the French day-ahead price throughout Q2 2021. Reversals were registered during the third week of April when France turned into a net power importer on the back of high demand and low nuclear output. Also, during the third week of May, high levels of wind and solar output coincided to drive the Spanish renewable penetration above 55% and France became a net importer of cheaper Spanish electricity. During the rest of the Q2 2021, the usual Spanish premium was maintained, due to lower rainfall and hydro output, depending mainly on French nuclear availability. The differential reached its maximum (23 €/MWh) during the first week of June with the improvement of the French nuclear availability and Spanish hydro stocks fell on seasonal decline.
- Spanish regulator CNMC approved an increased electricity grid investment for 2026 destined for renewable connections and international power links. The revised plan includes the 2 GW interconnection across the Bay of Biscay with France, which is scheduled to be online by 2027. Spain would need some 10 GW of cross-border transmission capacity to meet the 10% interconnection EU target. Currently, limited interconnection between France and Spain is a bottleneck in the European power market, where both sides could benefit from complementary seasonal swings in generation. Spain’s peak demand is during summer when France has a surplus with its peak demand in winter. Record-high power prices in Spain this summer have boosted flows from France amid a widening price spread.
- Bilateral trade with Morocco in Q2 2021 resulted in net imports of 119 GWh from Morocco. Another project approved by the CNMC is a third interconnection link with Morocco (700 MW), which is expected to be online by 2026.

**Figure 51 – Weekly flows between France and Spain and price differentials between them**

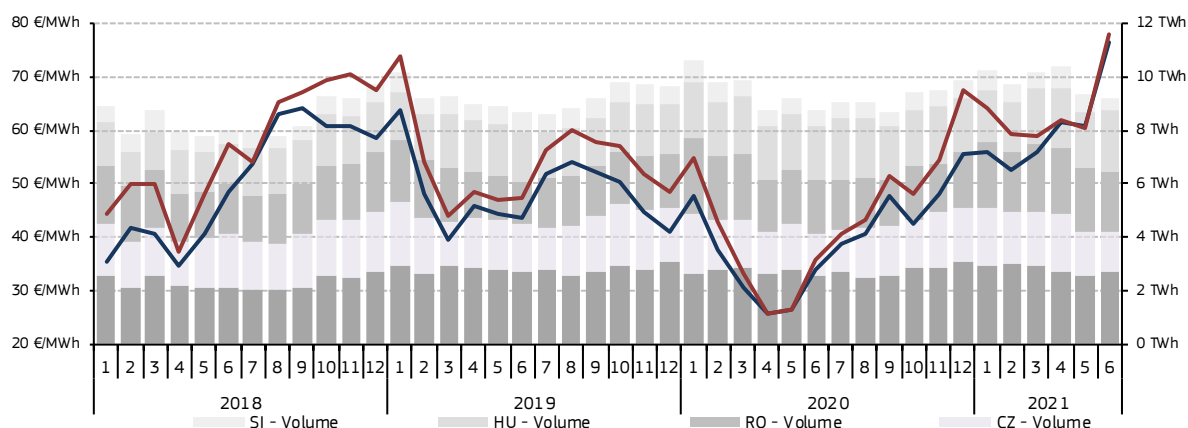


Source: ENTSO-E, OMEL, Platts

#### 4.6 Central Eastern Europe (Czechia, Hungary, Poland, Romania, Slovakia, Slovenia)

- Figure 53** shows that average monthly prices for baseload power in Central Eastern Europe exceeded historical levels from early 2012, reaching 78 €/MWh in June. Developments were driven by rising price in fuels, tighter supply-demand balance, and a recovery in demand. Baseload prices fell slightly in May, as renewable generation increased. Prices rebounded in June, on the back of high fuel prices and wind lulls. The gap between baseload and peakload monthly averages fell from 6% in March to 2% at the end of the Q2 2021, as peakload demand declined due to mild temperatures. When compared to Q2 2020, the average baseload price in the reference quarter rose by 132% to 66 €/MWh. Traded volumes in the reference quarter increased by 9% compared to the previous Q2.
- Polish electricity demand rose considerably during Q2 2021 in comparison with the previous year. Economic recovery and heatwaves in June supported the increase. The gap was filled by increased coal generation and net imports from Germany, Sweden and Lithuania. In May, a fire in Bełchatów coal power plant shut the largest unit (858 MW) until the end of the month. A HDVC 700 MW interconnector of 290 kilometres is expected to connect Poland and Lithuania by 2025. In May, TSOs from both countries approved the final investment decision. The link will allow the grids of Estonia, Latvia and Lithuania to be synchronised with those in Poland and other Member States.

**Figure 52 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)**



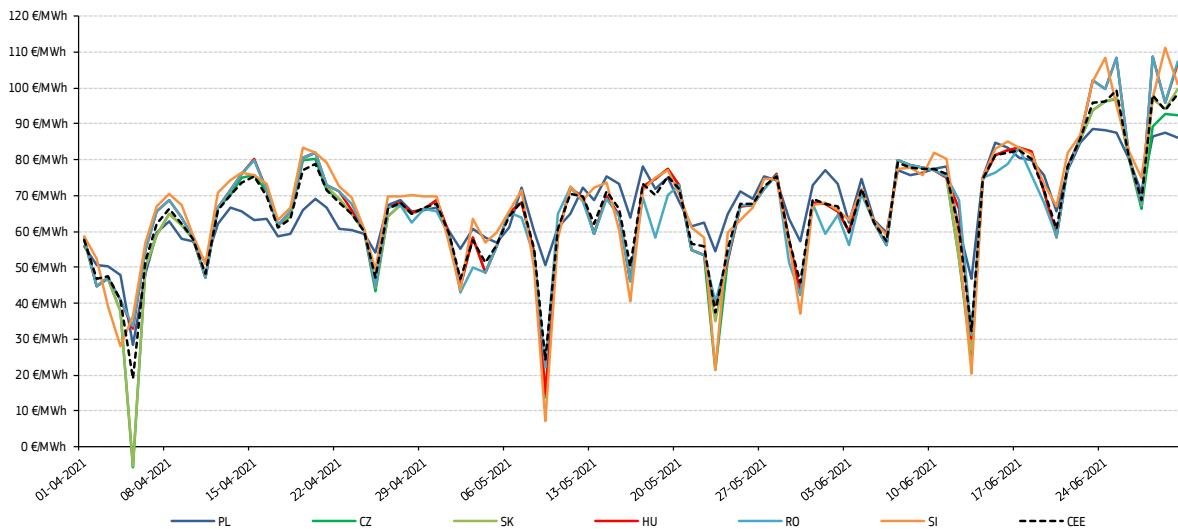
Source: Regional power exchanges, Central and Eastern Europe (CEE), CEE: PL, CZ, SK, HU, RO, SI

- Figure 54** shows that daily average baseload prices in the coupled markets (CZ, SK, HU, RO, PO) saw an increase in prices during Q2 2021, on the back of rising fuel prices, tightening supply-demand balance and ebbs and flows of wind availability. Prices moved between 55 and 70 €/MWh between April and May and among 65 and 85 €/MWh in

June. The Polish market, having started a day-ahead market in February 2021, significantly reduced its typical premium towards CEE prices from an average of almost 12 €/MWh in Q2 2020, to an overall gap of only 1€/MWh in Q2 2021. High prices have also affected Member States with reduced exposure to gas, such as Poland. The large coal-fired fleet has also been taking the impact of high CO<sub>2</sub> prices (and coal prices). This is an interesting signal towards renewables, as high penetration levels of solar and wind would reduce exposure of electricity prices to commodities (gas and carbon).

- The Pan-European day-ahead power market coupling was extended across six new borders during June. The project started in December 2018 and connects borders of the group integrated by Czechia, Slovakia, Hungary and Romania with the Multi Regional Coupling on the borders of Poland, Germany and Austria. Price coupling maximises the social welfare of market participants by allowing simultaneous calculation of prices and cross-border flows.

**Figure 53 – Daily average power prices on the day-ahead market in the CEE region**

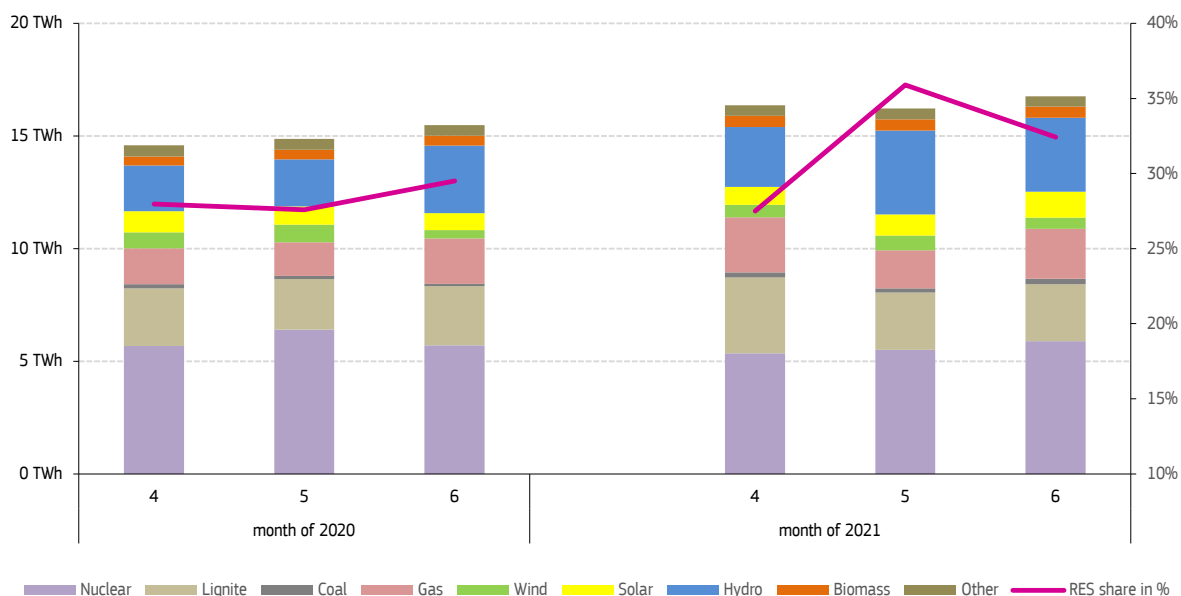


Source: Regional power exchanges

- **Figure 55** compares the combined electricity generation mix of the reference quarter of the CEE region (excluding Poland) and the quarter a year before. The most substantial change took place in hydro generation with added output of 2.5 TWh, due to increased Romanian generation (almost +2 TWh) and good conditions in Slovakia and Slovenia. Increasing power demand to saw higher gas generation in the mix (+1 TWh) in all countries. The lignite segment experienced an increase of 1 TWh in output. The share of renewables increased from 28% to 32% thanks to higher hydro generation in Romania, a solar surge in Hungary and increases in biomass generation in Czechia and Hungary. Nuclear remained the dominant generation technology with a 34% share in the mix, albeit a 6% decrease in output compared with Q2 2020. Total generation increased by 10%, in line with the rise in demand.



**Figure 54 – Changes in the electricity mix in the CEE region (excluding Poland) between Q2 2020 and Q2 2021**



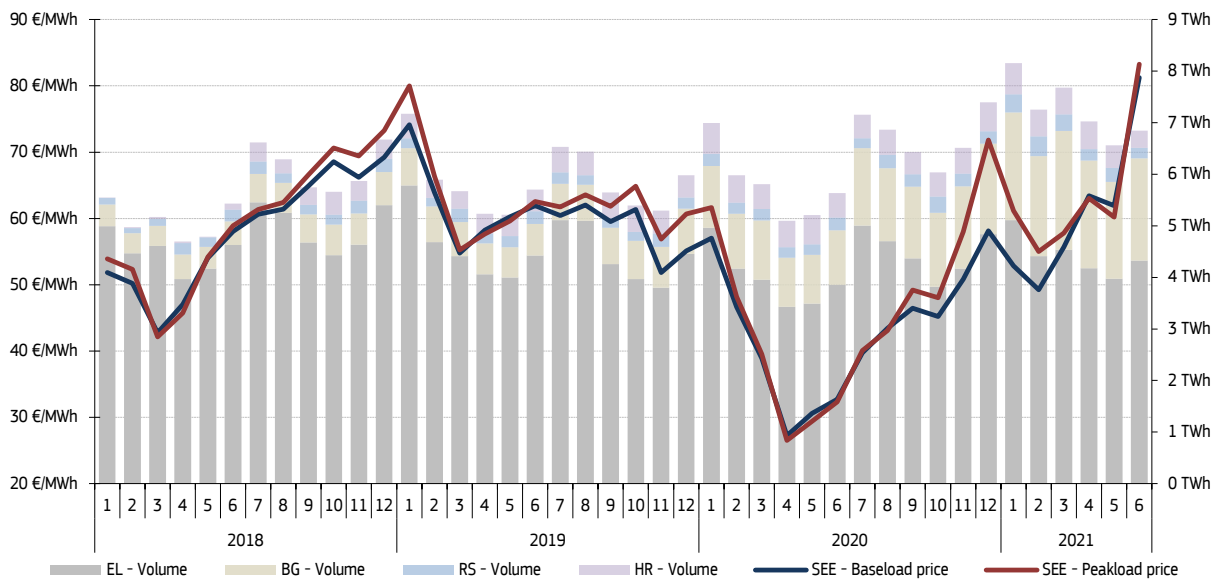
Source: ENTSO-E.

- In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share of coal and lignite in its mix slightly increased to 70% in Q2 2021 (compared to 69% in Q2 2020), thanks to improved demand. Renewables maintained their share at 19% year-on-year. Gas decreased its share in the mix to 10% year-on-year, underlining the limited short-term potential for coal-to-gas switching. The share of coal in Poland's mix should decrease to 56% by 2030 thanks mainly to significant wind capacity additions (especially in the offshore segment). Additionally, Europe's largest coal-fired plant, Bełchatów (5 GW), is planned to cease operations by 2036.

#### 4.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 56** shows that after increases in April, trade-weighted monthly average baseload prices in the SEE region fell slightly in May, only to rebound to 81 €/MWh in June, exceeding previous monthly record prices from the past years. Baseload prices in the region were driven by Greek prices (by far the most liquid market in the region). Increased demand and strong gas prices drove electricity prices up. The average quarterly baseload price rose by 128% year-on-year to 69 €/MWh in Q2 2021, 31% above Q1 2021 and 15% higher than Q2 2019. The average quarterly peakload price, rose 19% above Q2 2020 levels to 69 €/MWh.

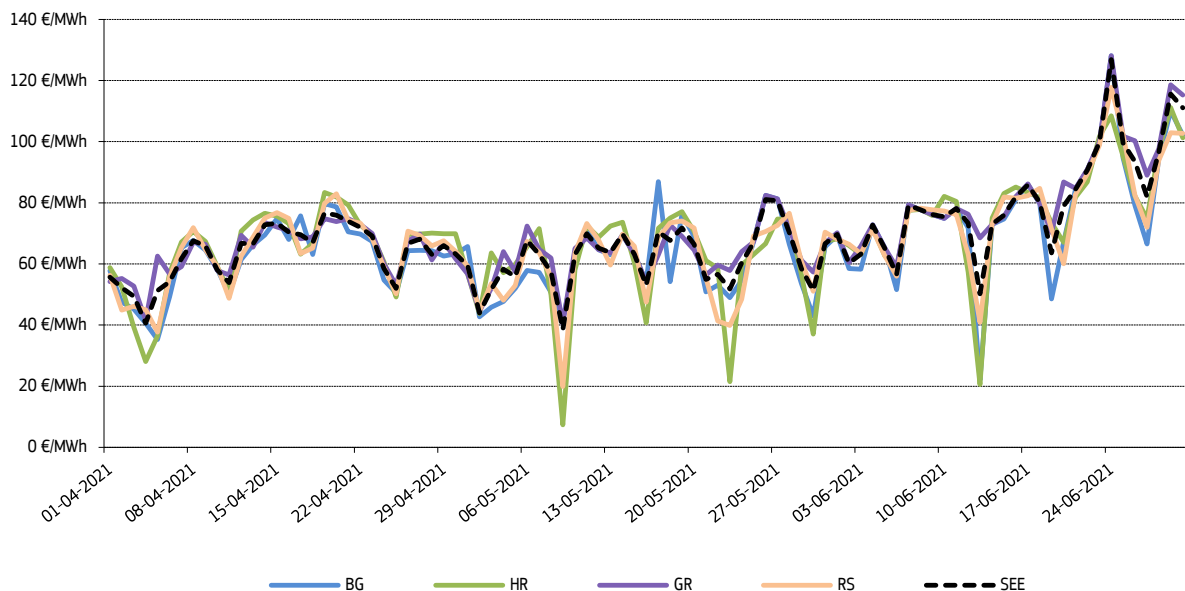
**Figure 55 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)**



Source: IBEX, LAGIE, CROPEX, SEEPEX

- Daily baseload price movements in individual markets were relatively well synchronised during Q2 2021, as shown in **Figure 57**. The usual Greek premium over the Bulgarian contracts decreased significantly in the reference quarter as the [Bulgarian day-ahead market was integrated](#) via the Greek border in the Pan-European day-ahead power market, with a first delivery on 12 May. Prices moved between 55 and 70 €/MWh during April and May, until they started to escalate on the back of gas prices and strong demand to a range of 70-90 €/MWh.
- Greece completed the first interconnector link to the island of Crete through a 400 MW cable. The link can cover a third of Crete's electricity demand. This project involves the longest AC submarine cable (174 kms.) from Crete to the Peloponnese.

**Figure 56 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia**



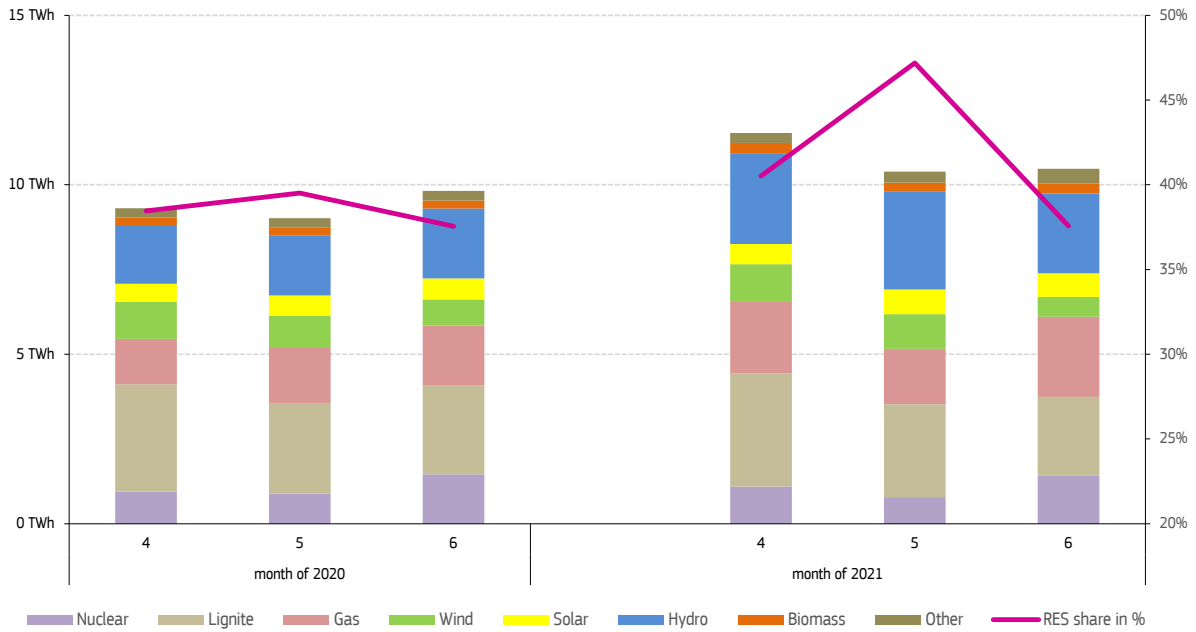
Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 58** compares the combined electricity generation mix of the SEE region between Q2 2020 and Q2 2021. Lignite output increased in Bulgaria (+15%), Greece (+36%) and Croatia (+28%), although the share of lignite in the regional mix fell from 30% to 26% year-on-year. The share of gas generation increased to 19% from 17% during the quarter, rising output levels by 29% compared with Q2 2020. Renewable penetration rose from 39% to 42% thanks to improved hydro output across the region. Lignite generation sector is scheduled for shutdown

in 2023. Ptolemaida V power plant (660 MW) will be converted to natural gas by 2025. Mytilineos new CCGT will supply power to the aluminium manufacturing industry from 2024.

- In May, Greece awarded 350 MW to below 20 MW solar projects at less than 40 €/MWh. Under the National Energy and Climate Plan (NECP), Greece has the goal to have 7.7 GW of solar capacity by 2030. Greece added 913 MW of solar capacity during the last year. The country is planning another five 350 MW auctions to 2024 with focus on utility-scale solar projects shifting to Power Purchase Agreements (PPAs).

**Figure 57 – Changes in the electricity generation mix in the SEE region between Q2 2020 and Q2 2021**



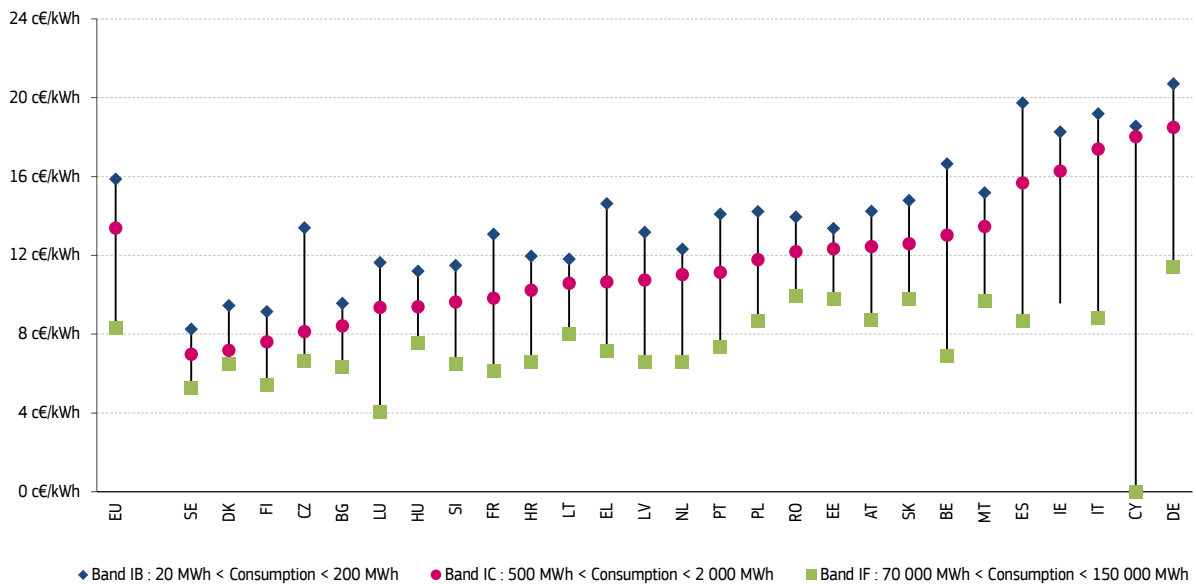
Source: ENTSO-E

## 5 Retail markets

### 5.1 Retail electricity markets in the EU

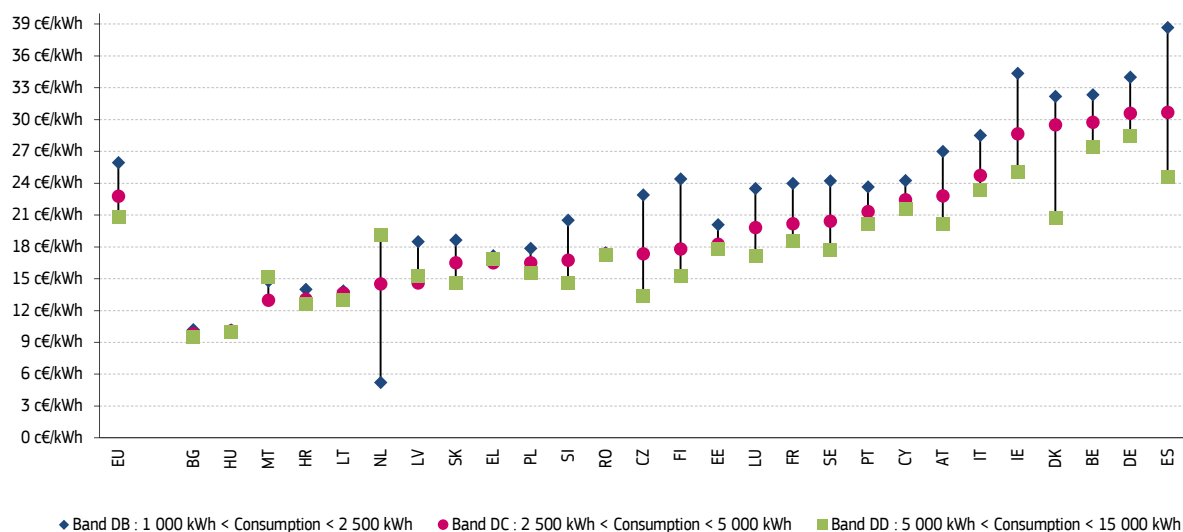
- **Figures 50 and 51** display the estimated retail prices in June 2021 in the 27 EU Member States for industrial customers and households. Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the second half of 2020) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per MWh consumed). Dutch, Maltese, Greek and Latvian household prices are a notable exception.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Germany (20.7 c€/kWh) and Spain (19.7 c€/kWh), followed by Italy and Cyprus (19.2 and 18.6 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (8.3 c€/kWh) and Finland (9.2 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. Compared to June 2020, the average assessed EU retail price for the IB band rose by 12% to 15.9 c€/kWh. On the other side of the consumer spectrum, industrial companies with large annual consumption (band IF), including most energy-intensive users, paid the highest prices in Germany (11.4 c€/kWh both), followed by Romania (9.9 c€/kWh) and Slovakia (9.8 c€/kWh). Luxembourg (4.0 c€/kWh) was assumed to have by the lowest prices, with Sweden and Finland (5.3-5.4 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was above 2:1 for this consumer type. Compared to June 2020, the average assessed EU retail electricity price for the IF band rose by 19% to 8.3 c€/kWh.
- In the household segment, Germany (28.5 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (27.4 c€/kWh), and with Ireland (25.1 c€/kWh) in the third place. The lowest prices for big households were calculated for Bulgaria (9.5 c€/kWh) and Hungary (10.0 c€/kWh). Compared to June 2020, the average assessed EU retail electricity price for the DD band rose by 7% to 20.8 c€/kWh. In the case of small households, Spain saw the highest prices (38.7 c€/kWh), followed by Ireland (34.4 c€/kWh), while Bulgaria and Hungary (both at 10.2 c€/kWh), found themselves again on the other side of the price spectrum. Compared to June 2020, the average assessed EU retail electricity price for the DB band rose by 7% to 25.9 c€/kWh.

**Figure 58 – Industrial electricity prices, June 2021 – without VAT and recoverable taxes**



Source: Eurostat, DG ENER. Data for the IF band for CY is either confidential or unavailable.

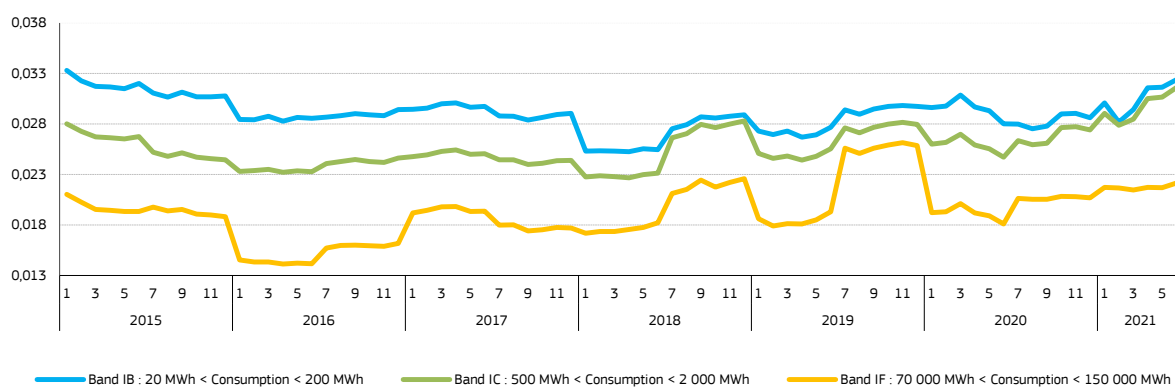
**Figure 59 – Household electricity prices, June 2021 – all taxes included**



Source: Eurostat, DG ENER

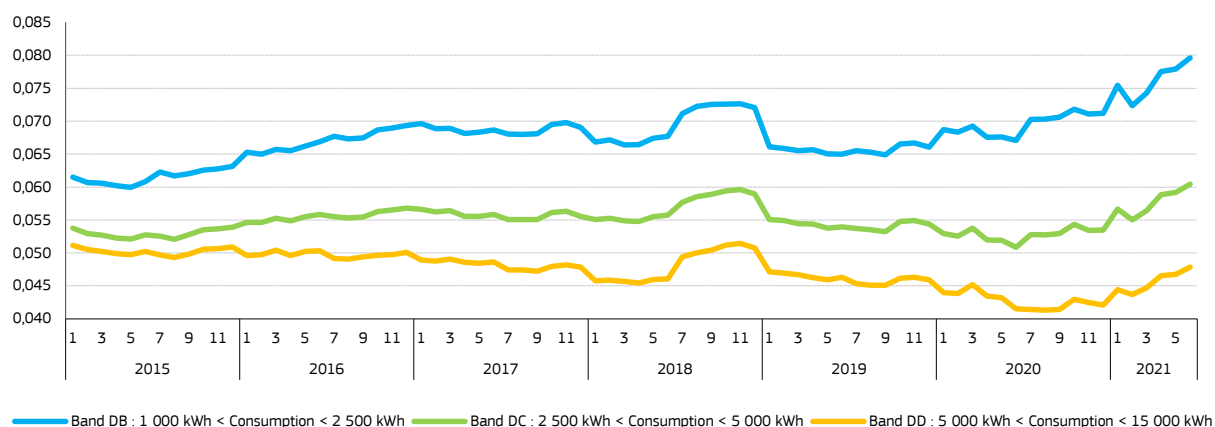
- **Figure 61 and Figure 62** display the convergence of retail prices across the EU over time, by depicting their standard deviation. Industrial prices for small and medium-sized businesses showed increasing divergence in Q2 2021, at a higher pace than in the previous quarter. In the case of retail prices for large businesses, there was a slight increase of the standard deviation compared with June 2020.
- In the household sector, price divergence increased during Q2 2021. In fact, besides from prices for large consumption households, household prices reached the highest level of divergence on record. Household prices tend to be more impacted by regulated elements (network charges, taxes and levies) so their variation across Member States is greater than in the case of industrial consumers.

**Figure 60 – Standard deviation of retail electricity prices in the EU for industrial consumers**



Source: Eurostat, DG ENER

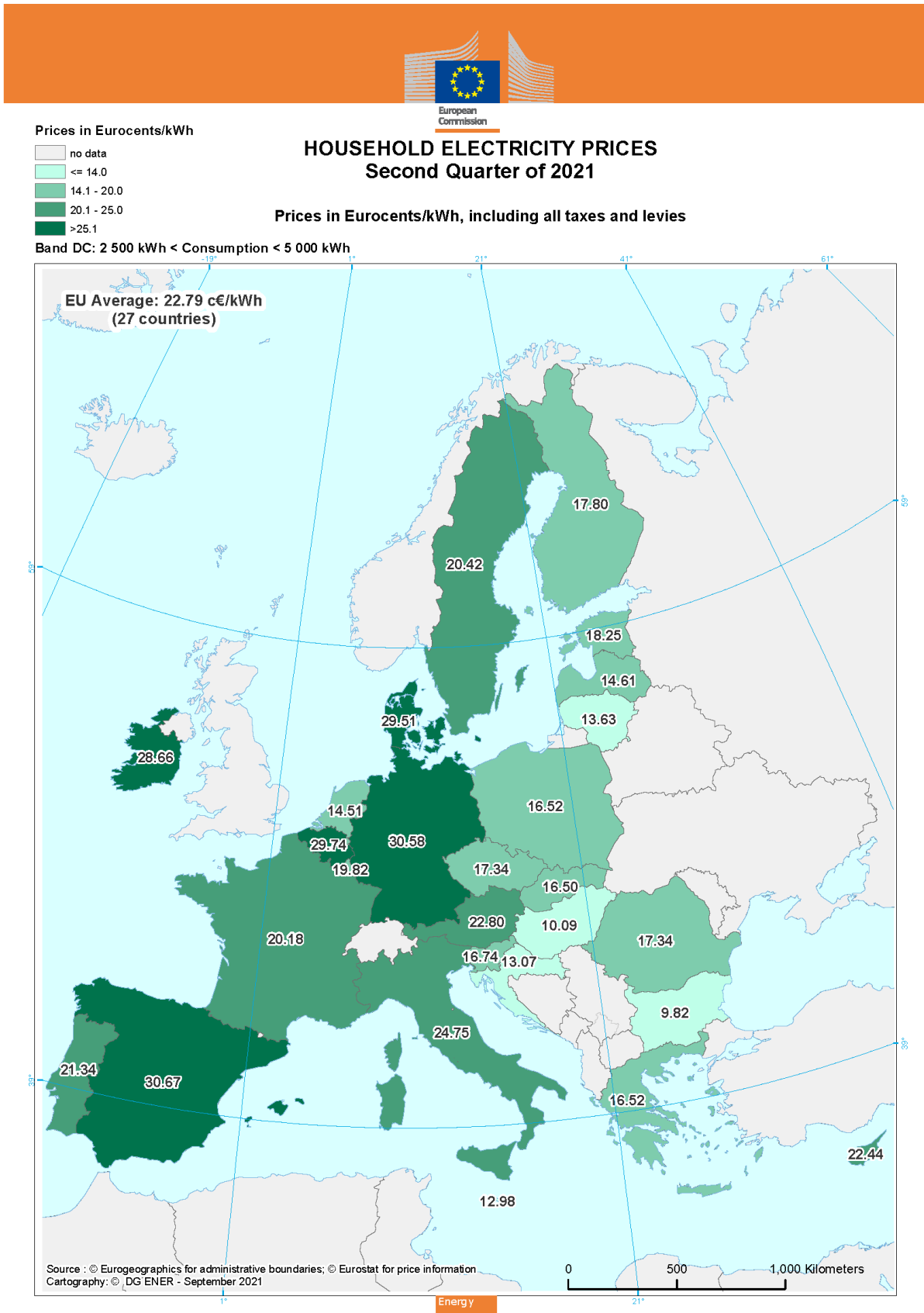
**Figure 61 – Standard deviation of retail electricity prices in the EU for household consumers**



Source: Eurostat, DG ENER

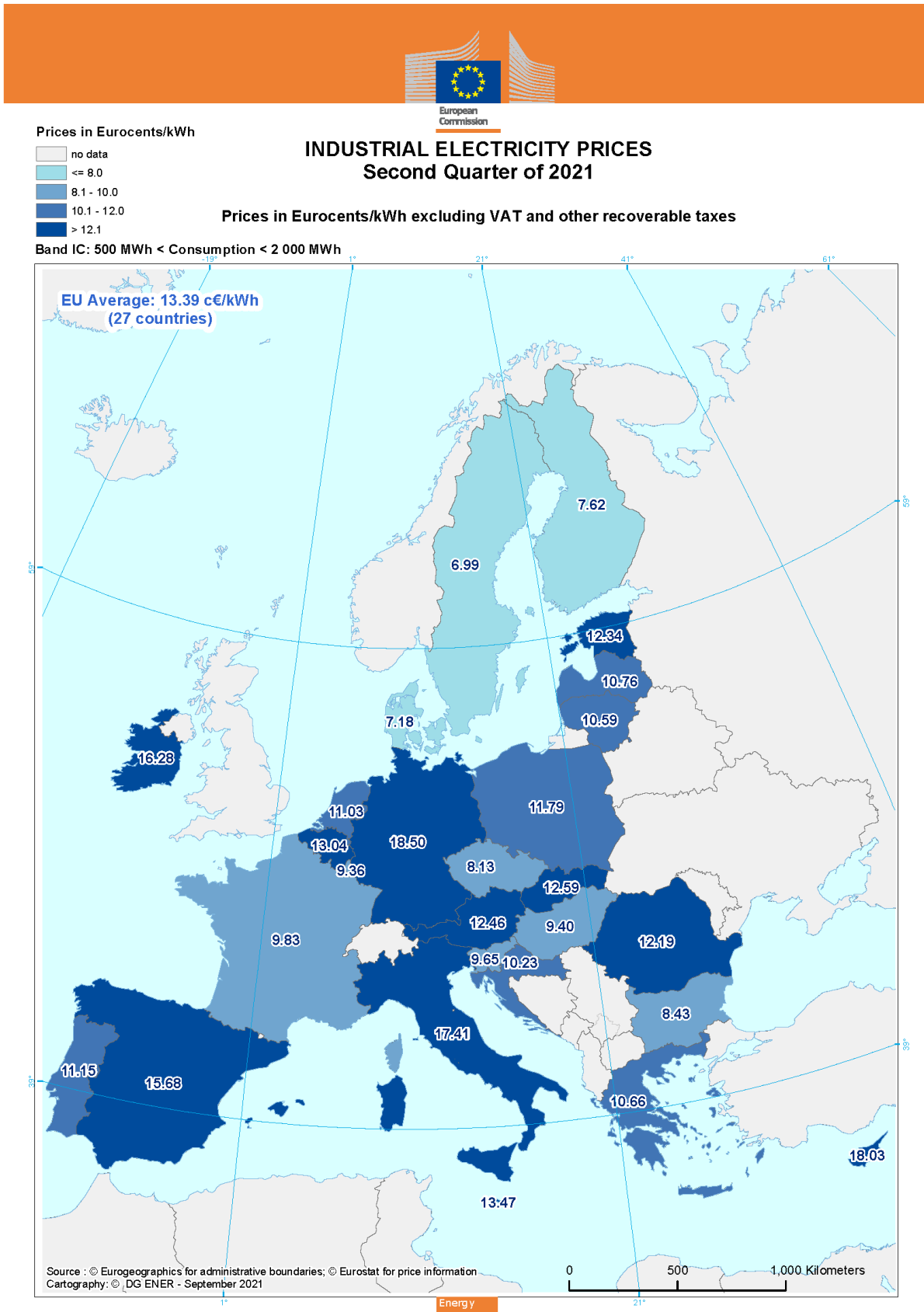
- Figures 63 and 64** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q2 2021. In the case of household prices, Spain topped the list (30.7 c€/kWh), followed by Germany (30.6 c€/kWh) and Belgium (29.7 c€/kWh). As was the case in previous quarters, Bulgaria (9.8 c€/kWh) and Hungary (10.1 c€/kWh) retained their position as Member States with the cheapest household electricity prices. The EU average increased by 7% in the reference quarter compared to June 2020. The largest year-on-year increases in the household category were assessed in Spain (+47%), Estonia (+43%) and Romania (+20%). The biggest year-on-year falls were estimated for Czechia (-9%) and Latvia (-8%). See **Figure 65** for more details.
- In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q2 2021 (7.0 c€/kWh), followed by Denmark and with Finland taking the third place. Meanwhile, Germany (11.4 c€/kWh) and Cyprus stood at the other end of the spectrum. At 13.4 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 16% compared to Q2 2020.

**Figure 62 – Household Electricity Prices, second quarter of 2021**



Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices

**Figure 63 – Industrial Electricity Prices, second quarter of 2021**

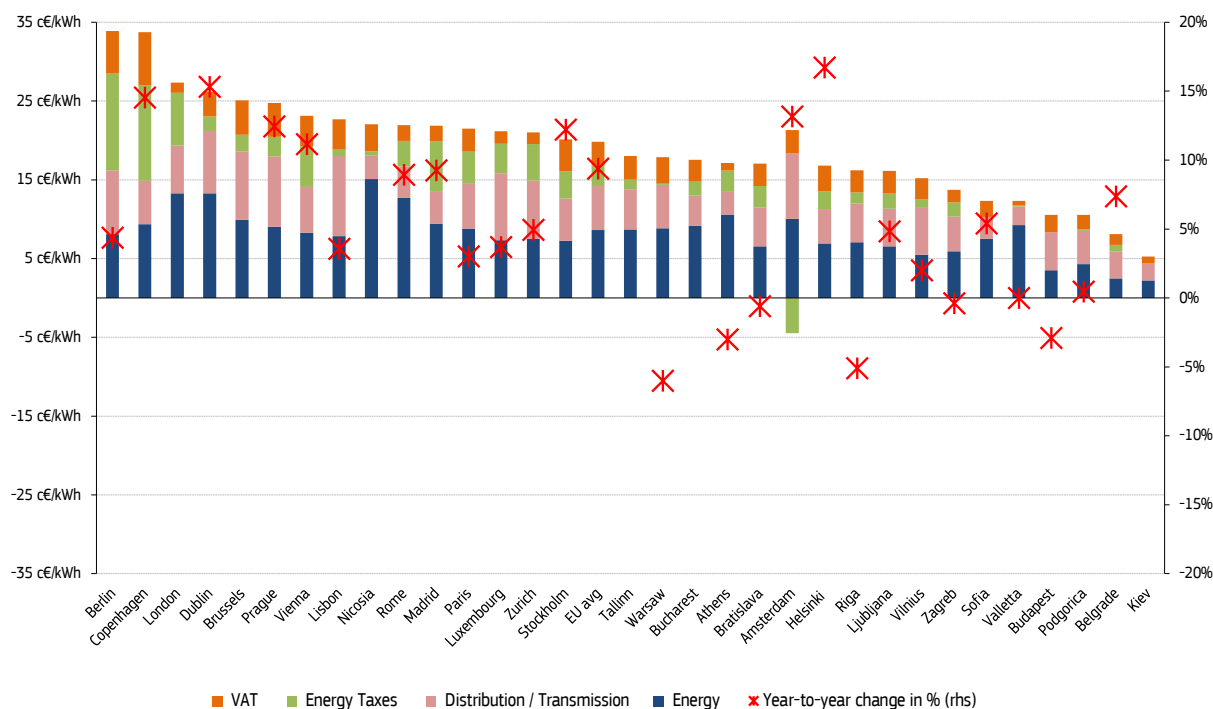


Source : Data computed from Eurostat half-yearly retail electricity prices and consumer price indices



- **Figure 65** shows retail electricity prices for representative household consumers in European capital cities and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). In August 2021, the highest prices were observed in Berlin and Copenhagen (33.9 and 33.7 c€/kWh, respectively) where energy taxes accounted for more than a third of the final bill. The lowest prices among EU capitals were recorded in Budapest and Valletta (10.6 c€/kWh and 12.3 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 60**. EU-wide, retail prices have been climbing since the end of 2020. Inflation pressures have intensified throughout the year, due to rising wholesale prices, which were driven, among other factors, by increased demand, high gas prices, and more expensive emission allowances.
- The highest levels of the energy component in Europe were reported from Nicosia, Dublin, and London (13-15 c€/kWh), cities in relatively isolated island markets. The lowest levels of the energy component (2-3 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Kiev, Belgrade, Budapest). The EU average for the energy component was 8.6 c€/kWh (up from 7.2 c€/kWh in August 2020). Out of the 27 capitals, 14 had a more expensive energy component than the EU average.
- The highest network charges were recorded in Lisbon (10.2 c€/kWh), Prague and Brussels (8.9 c€/kWh and 8.7 c€/kWh, respectively) where they accounted between 35%-46% of the total price and in most of the cases were higher than the energy component. The lowest network fees were collected in Valletta (2.3 c€/kWh) and Sofia (2.8 c€/kWh). The EU average in the reference quarter was 5.6 c€/kWh (slightly up from 5.5 c€/kWh in August 2020).
- Apart from Berlin and Copenhagen (12 c€/kWh), the highest energy taxes were paid by households in London and Madrid (6 c€/kWh). Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 2.6 c€/kWh (down from 2.7 c€/kWh in August 2020). Varied VAT rates applied to electricity, ranging from 5% in Malta and London to 21% in Hungary, also contribute to differences in household prices across Europe.
- The tax reduction subcomponent (tax credit) that applies to electricity customers in the Netherlands is currently higher than the annual energy tax amount that corresponds to a typical residential customer in Amsterdam. Even in cases when the tax credit is higher than the tax amount, the customers still receive the full credit as a discount from their overall annual bill. In practice, this has resulted in a negative value of the Dutch tax component in the price breakdown. This development has also significantly reduced household electricity prices countrywide, which is visible in **Figure 60**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

**Figure 64 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, August 2021**

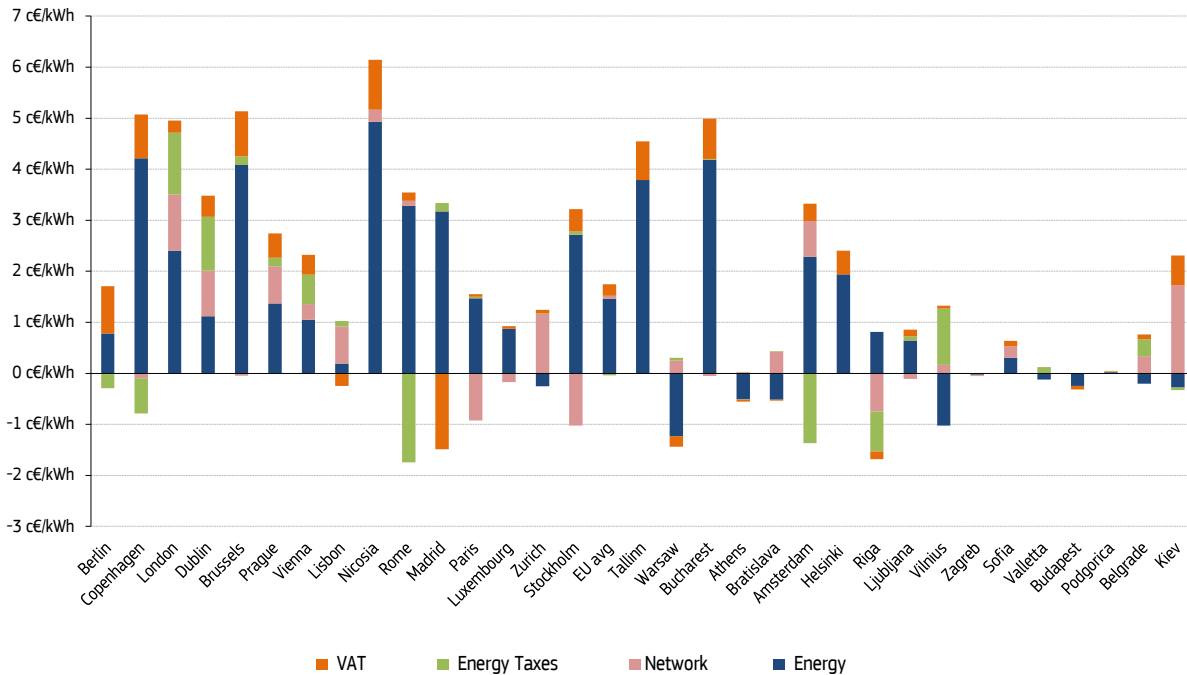


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in the European Union in August 2021 were observed Bucharest and Nicosia (+39%) and Tallinn (+34%). As shown in **Figure 66**, rising prices were driven by increasing wholesale prices in Romania, Cyprus and Estonia. In fact, the rise of wholesale

prices was the most important factor for the increase of end user prices in 19 of the 27 EU capitals. 6 of the 27 EU capitals reported prices lower or unchanged compared to the same month of the previous year, with Warsaw (-6%) and Riga (-5%) posting the largest relative drops. Households in the Polish capital benefited mainly from lower network charges, whereas the price fall in the Latvian capital was driven mainly by a lower energy component.

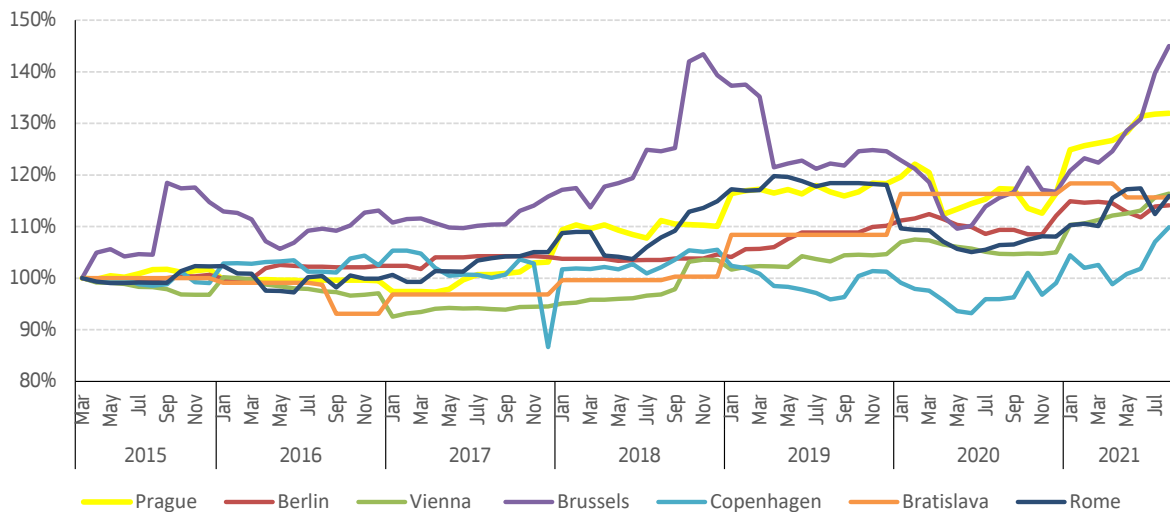
**Figure 65 – Year-on-year change in electricity prices by cost components in the European capital cities comparing August 2021 with August 2020**



Source: Vaasaett

- Figure 67** compares how household retail prices in selected EU capitals changed in relative terms over the last six years. The biggest increase (+45%) was registered in Brussels and was driven mainly by a rising VAT component (13% of the change). Prague came in second with a 32% increase since February 2015, followed by Rome (+16%) and Bratislava (+16%). On the other end, retail prices for households in Copenhagen which have been more or less the same they were six years ago, have recently experienced a rise (+10% compared to February 2015) due to an increase in the energy component.

**Figure 66 – Relative changes in retail electricity prices in selected EU capitals since 2015**

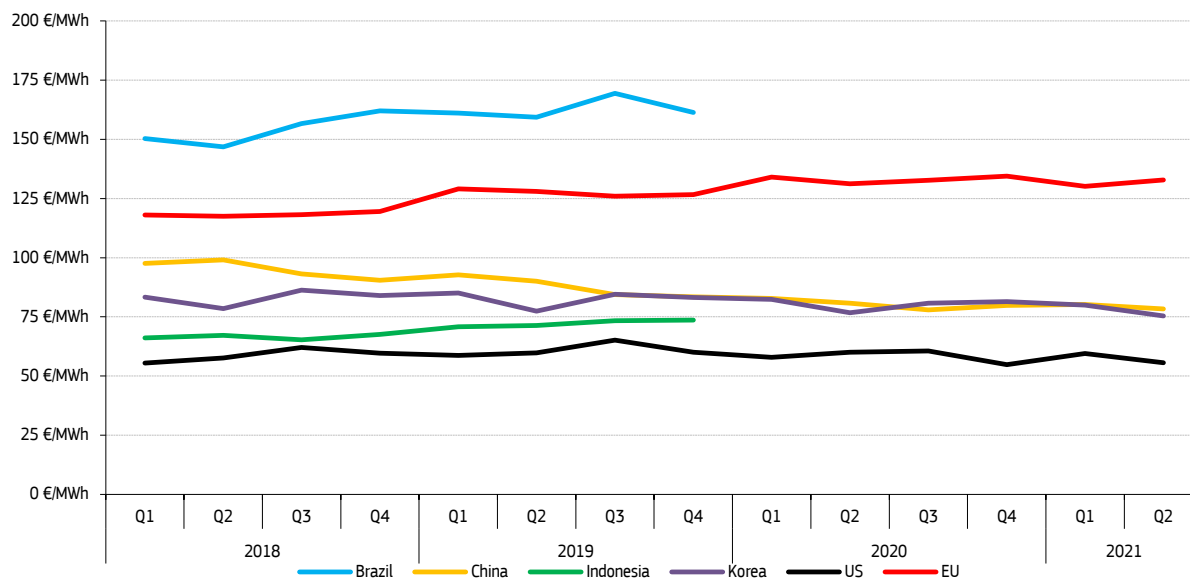


Source: Vaasaett

## 5.2 International comparison of retail electricity prices

- **Figure 68** displays industrial retail prices paid by consumers in the EU and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.
- Electricity prices for industrial users in the EU rose by 2% in Q2 2021 compared to the previous quarter. Meanwhile, Chinese industrial prices decreased less by 2%, returning to a steady downward trend observed over the past two years. Industrial electricity prices in the United States fell by 6% quarter-to-quarter in Q2 2021.

**Figure 67 – Retail electricity prices paid by industrial customers in the EU and its main trading partners**



Source: Eurostat, IEA, CEIC, DG ENER computations. The latest data for Brazil and Indonesia is not available.

## Glossary

**Backwardation** occurs when the closer-to-maturity contract is priced higher than the contract which matures at a later stage.

**Clean dark spreads** are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. If the level of dark spreads is above 0, coal power plant operators are competitive in the observed period. *See dark spreads.*

**Clean spark spreads** are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. If the level of spark spreads is above 0, gas power plant operators are competitive in the observed period. *See spark spreads.*

**Contango:** A situation of contango arises when the closer to maturity contract has a lower price than the contract which is longer to maturity on the forward curve.

**Cooling degree days (CDDs)** are defined in a similar manner as Heating Degree Days (HDDs); the higher the outdoor temperature is, the higher is the number of CDDs. On those days, when the daily average outdoor temperature is higher than 21°C, CDD values are in the range of positive numbers, otherwise CDD equals zero.

**Dark spreads** are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 36% efficiency. Dark spreads are given in this publication, with the coal and power reference price as reported by *Bloomberg*.

**Emission allowances' spot prices** are defined as prices for an allowance traded on the secondary market and with a date of delivery in the nearest December.

**European Power Benchmark (EPB9)** is a replacement of the former Platt's PEP index discontinued at the end of 2016, computed as weighted average of nine representative European markets' (Belgium, Czechia, France, Italy, Germany, Netherlands, Spain, the United Kingdom and the Nord Pool system price) day-ahead contracts.

**EPS** is a consumption-weighted baseload benchmark of five most advanced markets offering a 3-year visibility into the future. Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices are rolled over towards the end of each year, meaning that the year-ahead benchmark in 2018 shows the price for 2019; and the year-ahead curve in 2019, in turn, shows baseload prices for delivery in 2020.

**Flow against price differentials (FAPDs):** By combining hourly price and flow data, FAPDs are designed to give a measure of the consistency of economic decisions of market participants in the context of close to real time operation of electrical systems.

With the closure of the day-ahead markets (D-1), the prices for each hourly slot of day D are known by market participants. Based on the information from the power exchanges of two neighbouring areas, market participants can establish hourly price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event named 'flow against price differentials' (FAPD) occurs when commercial nominations for cross border capacities are such that power is set to flow from a higher price area to a lower price area. The FAPD chart in this quarterly report provides detailed information on adverse flows, presenting the ratio of the number of hours with adverse flows to the number of total trading hours in a quarter.

**Heating degree days (HDDs)** express the severity of a meteorological condition for a given area and in a specific time period. HDDs are defined relative to the outdoor temperature and to what is considered as comfortable room temperature. The colder is the weather, the higher is the number of HDDs. These quantitative indices are designed to reflect the demand for energy needed to heat a building.

**Long-term average for HDD and CDD comparisons:** In the case of both cooling and heating degree days, actual temperature conditions are expressed as the deviation from the long-term temperature values (average of 1978-2018) in a given period.

**Monthly estimated retail electricity prices:** Twice-yearly Eurostat retail electricity price data and the electricity component of the monthly Harmonised Index for Consumer Prices (HICP) for each EU Member States to estimate monthly electricity retail prices for each consumption band. The estimated quarterly average retail electricity prices on the maps for households and industrial customers are computed as the simple arithmetic mean of the three months in each quarter.

**Relative standard deviation** is the ratio of standard deviation (measuring the dispersion within a statistical set of values from the mean) and the mean (statistical average) of the given set of values. It measures in percentage how the data points of the dataset are close to the mean (the higher is the standard deviation, the higher is the dispersion). Relative standard deviation enables to compare the dispersion of values of different magnitudes, as by dividing the standard deviation by the average the impact of absolute values is eliminated, making possible the comparison of different time series on a single chart.

**Retail prices** paid by households include all taxes, levies, fees and charges. Prices paid by industrial customers exclude VAT and recoverable taxes. Monthly retail electricity prices are estimated by using Harmonised Consumer Price Indices (HICP) based on bi-annual retail energy price data from Eurostat.

**Spark spreads** are reported as indicative prices giving the average difference between the cost of natural gas delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a gas-fired plant with 49% efficiency. Spark spreads are given with the gas and power reference price as reported by *Bloomberg*.

**Tariff deficit** expresses the difference between the price (called a tariff) that a *regulated utility*, such as an electricity producer is allowed to charge and its generation cost per unit.

