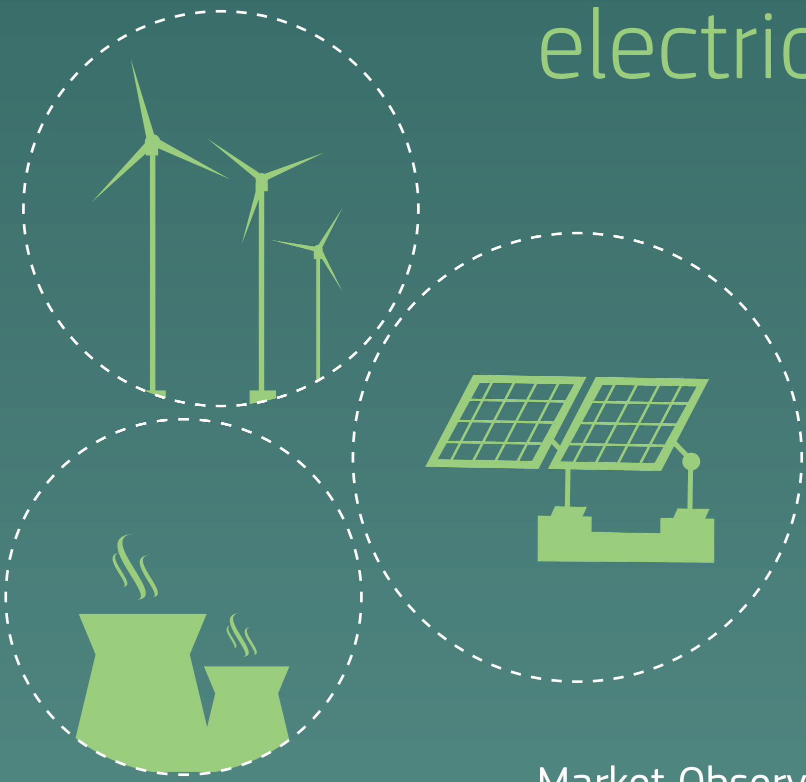
European Commission

Quarterly report
On European electricity markets



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CONTENT

HIGHLIGHTS OF THE REPORT

- **The second quarter of 2022 was marked by the impact of the developments following Russia's unprovoked invasion against Ukraine, high energy commodity prices (mainly gas, but also coal), reduced flows of pipeline gas and the uncertainty of the markets concerning European security of gas supply.** High gas price, lower availability of nuclear power plants and weak hydroelectric output due to droughts exerted additional pressure on the wholesale electricity market. The market continued reacting to announcements impacting the price of gas in Europe, related to the uncertainty of gas supplies from Russia, and policy responses from the EU and its Member States.

- **High energy commodity prices, especially gas** (fuel often used in the power plants setting the marginal wholesale electricity price), **continued to support high wholesale electricity prices and volatility during Q2 2022**. In Q2 2022, the largest year-on-year price increases in Member States were registered in France (+254%), Greece (238%), and Italy (+234%). Prices in France were influenced by the subdued nuclear output and the reversal of net export power flows in the context of high gas prices**. The European Power Benchmark was 191 €/MWh on average in Q2 2022**, 181% higher on yearly basis. Prices rose considerably in almost every market in Europe (price changes ranged from 50% to more than 250%). The highest price rises during the quarter were in Malta and Italy (252 and 249 €/MWh, respectively; 211% and 234 higher than in Q2 2021.

- **Electricity consumption in the EU registered a small decrease (-0.4%) compared with last year's levels in Q2 2022**, following the impact of high electricity prices and the subsequent industrial demand reduction, despite the increase of economic activity. Electricity consumption levels for the second quarter of 2022 were below the 2017-2019 range.

- **The share of renewables managed to increase its share to 43%, outplaying fossil fuels (36%) during the second quarter of 2022.** Renewable generation improved its output by 2% (+5 TWh) year-on-year. This was the result of an increase of 24% in solar generation (+13 TWh), 10% of onshore wind (+7 TWh) and 11% of offshore wind (+1 TWh), despite hydro generation falling by 16% (-15 TWh) on yearly basis. Nuclear generation remained under pressure due to unplanned outages and scheduled maintenance in France, decreasing its output by 17% (-27 TWh) in Q2 2022.

- **Reduced output levels of nuclear and hydro generation allowed fossil fuel generation to increase by 6% (+12 TWh) year-on-year in Q2 2022, despite high energy commodity prices**. Coal and lignite generation rose by 19% (+15 TWh), whereas less CO_2-intensive gas generation fell by 7% (-7 TWh). Based on preliminary estimates, the Q2 2022 carbon footprint of the EU power sector rose by 10% compared to Q2 2021.

- **Carbon prices registered high levels of volatility throughout Q2 2022.** Carbon allowances bounced back to prices around 80-85 €/tCO_2 during the quarter, reaching a peak of 91 €/tCO_2 in mid-May. Elevated gas prices have contributed to rise carbon prices as they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. However, curbed levels of industrial demand due to high energy prices are putting downward pressure on carbon prices. The interaction between these factors has contributed to the decoupling between EU ETS and TTF price observed in previous quarters.

- **High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well**. Moreover, government interventions in Member States are helping to alleviate the bill for consumers. On 14 of June, the **'Iberian exception'** came into force in the form of an exceptional cap on the price of gas used for power generation in the day-ahead markets of the Iberian Peninsula (Spain and Portugal).

- **Retail electricity prices for household costumers in EU capital cities were up by 54% in August 2022**, compared with the same month in 2021. Highest increases in EU Member States prices were registered in Italy and Estonia (+131%). The energy component share now surpasses 50% of the total retail price in 20 EU capitals, up from 8 in Q2 2021. Retail electricity prices for industrial customers also increased, estimated at 32% higher year-on-year in Q2 2022 for mid-sized industrial consumers. Industrial retail electricity prices in the EU were higher compared to many trading partners, implying cost disadvantages, especially for energy intensive industries. The increases in retail prices could continue ahead the next heating season, as there is still room for wholesale prices to be passed through to consumer contracts.

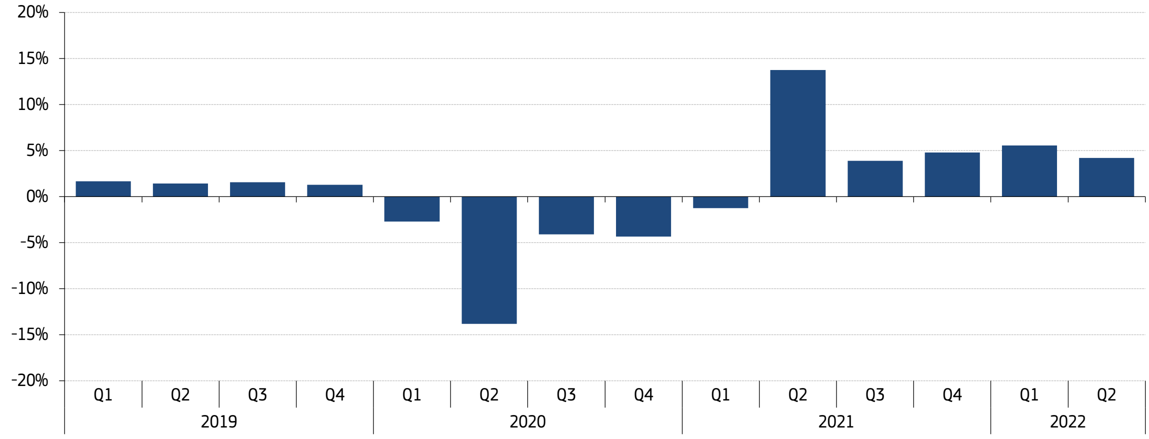
- Demand for electrically charged vehicles (ECV) positioned Q2 2022 as the fourth highest quarterly figure on record. **Almost 440,000 new ECVs were registered in the EU in Q2 2022.** However, sales registered a slight decrease during the second quarter of 2022 in comparison with Q2 2021(-1%). EU proposals linked to Green Deal initiatives and national policies continue to support the adoption of ECVs in Europe. Q2 2022 numbers translated into a 19% of market share, lower than China and almost three times higher than in the United States.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows the state of the economic recovery from the pandemic shock. According to an estimate published by Eurostat in September 2022, seasonally adjusted GDP in the EU increased by 4.2% year-on-year between April and June 2022. Although lower than the GDP growth registered during Q1 2022 (5.4%), the growth of the reference quarter is an example of the scale of the economic recovery. However, the increase in economic activity did not really translate in higher electricity consumption in the EU, as high electricity prices prompted the decreased use of electricity in energy-intensive sectors. This quarter is the fifth registering positive growth since the five consecutive negative growth quarters that followed the start of the pandemic. A rise in output was observed in every Member State. Double digit increases were reported in Ireland (+10.8%), followed by Malta (+8.3%) and Slovenia (+8.3%). The lowest year-on-year growths were observed in Estonia (+0.3%), Luxembourg (+1.6%), Germany (+1.7%) and Slovakia (+1.7%).

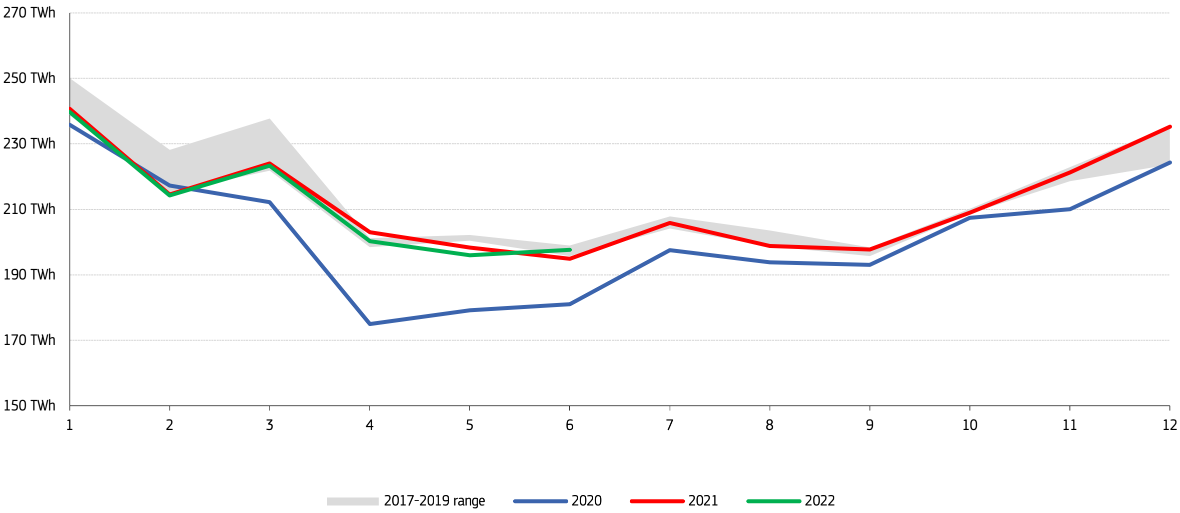
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU registered a small decrease (-0.4%) compared with last year's levels in Q2 2022, following the impact of high electricity prices and the subsequent industrial demand reduction. Demand has already returned to pre-pandemic levels; however, demand levels for the second quarter of 2022 were below the 2017-2019 range, registering lower levels in May, while higher than the average demand in June.

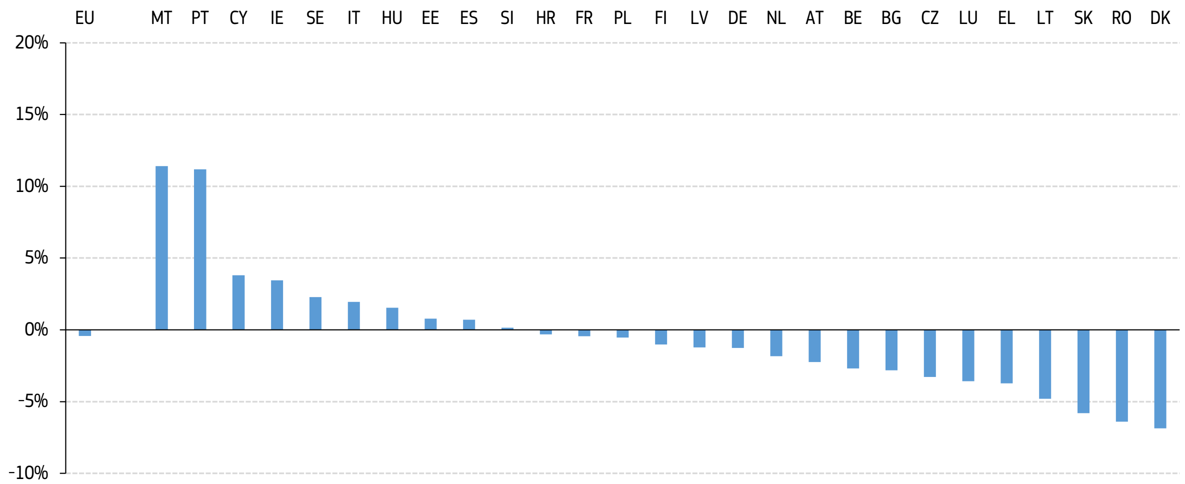
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- **Figure 3** sums up changes in electricity consumption over the second quarter of 2022, compared to Q2 2021. It is important to note that the EU average hides wide differences of developments in individual Member States. Only nine Member States saw an increase in consumption year-on-year, registering considerable grows in Malta (+11%) and Portugal (+11%). In addition, Slovenia, Croatia and France remained practically unchanged, while fifteen Member States registered a drop in consumption, led by Denmark (-7%), Romania and Slovakia (-6%). Of the major economies, power consumption went up in Italy (+2%) and Spain (+1%), while decreases were registered in the Netherlands (-2%), Germany (-1%) and France (-0.4%). Overall, large industrial consumers, responsible for the biggest portion of the demand, are already struggling with high energy prices, resulting in a decrease of the consumption. Compared to Q2 2021, EU-wide consumption decreased less than 1%, on the back of the impact of high energy prices in the industrial activity.

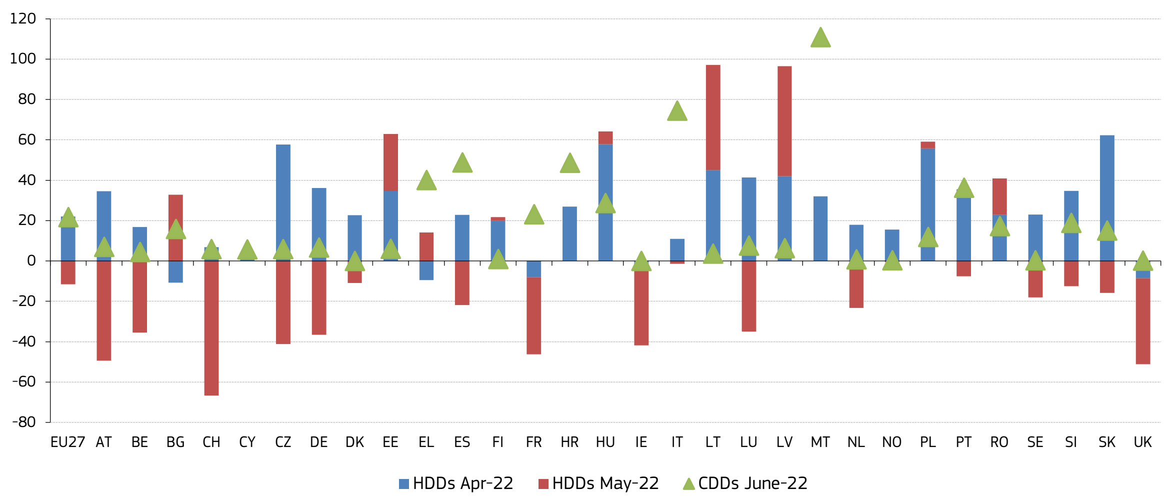
Figure 3 – Annual changes in electricity consumption in Q2 2021 and Q2 2022 by Member State



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 2022. EU-wide, the reference quarter was slightly warmer than the historical range, registering 11 HDDs above the long-term average (concentrated mainly in April) and 21 Cold Degree Days (CDDs) in June. In general, temperatures during Q2 2022 were higher than usual, mainly due to warmer weather in June. Some Mediterranean countries experienced hot temperatures in June (Malta, Italy, Spain, Croatia). Higher temperatures imply additional cooling needs, having a potential impact on gas-fired generation. Overall, April was colder than the historical average, while May and June registered warmer-than-usual temperatures during the quarter.

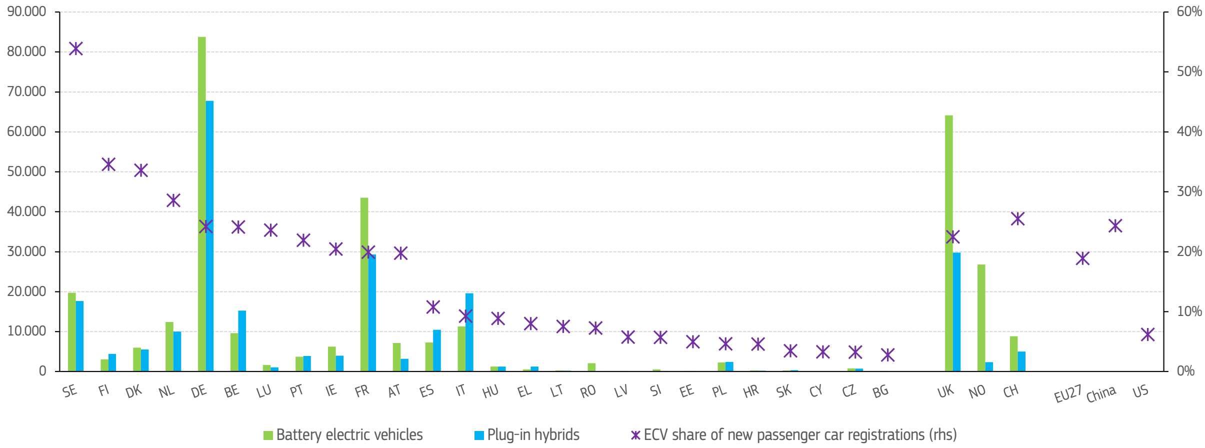
Figure 4 - Deviation of actual heating days from the long-term average in April-June 2022



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

- **Figure 5** shows that almost 440,000 new ECVs were registered in the EU in Q2 2022 (+4% compared with Q1 2022 and -1% year-on-year). Despite registering a decrease compared with Q2 2021, this is the fourth highest quarterly figure on record (after sales in Q4 2021, Q2 2021 and Q4 2020) and translates into a 19% market share; lower than China (29%), but higher than in the United States (7%). The battery electric vehicles segment continued to grow (+11% year-on-year to more than 233,000) while demand for plug-in hybrid vehicles decreased for another quarter (-12% year-on-year to almost 207,000). Hybrid electric vehicles (not chargeable) sales amounted to 535,000, higher than the ECV category. EU proposals linked to Green Deal initiatives and national policies continue to support the adoption of ECVs in Europe.
- The highest ECV penetration was once again observed in Sweden, where more than half of the passenger cars sold could be plugged, thanks to the support of a climate bonus for battery-powered electric vehicles (BEV) owners in Sweden and new zero-emission cars and light trucks. From July 2022 and January 2023, new CO2 limits for the climate bonus take place, increasing the emissions requirement to opt for this bonus. In addition, more than a third of the Q2 2022 car sales in the Netherlands, Denmark and Finland were ECVs. Germany retained the position of the largest individual market (almost 155,000 ECV sales in Q2 2022) thanks to its generous incentive programme, which since 2020 and until the end of 2022, offers up to €9,000 in direct purchase bonuses. After Germany, numbers in ECVs were also supported by France, where sales amounted to more than 83,000 new ECVs in the reference quarter.

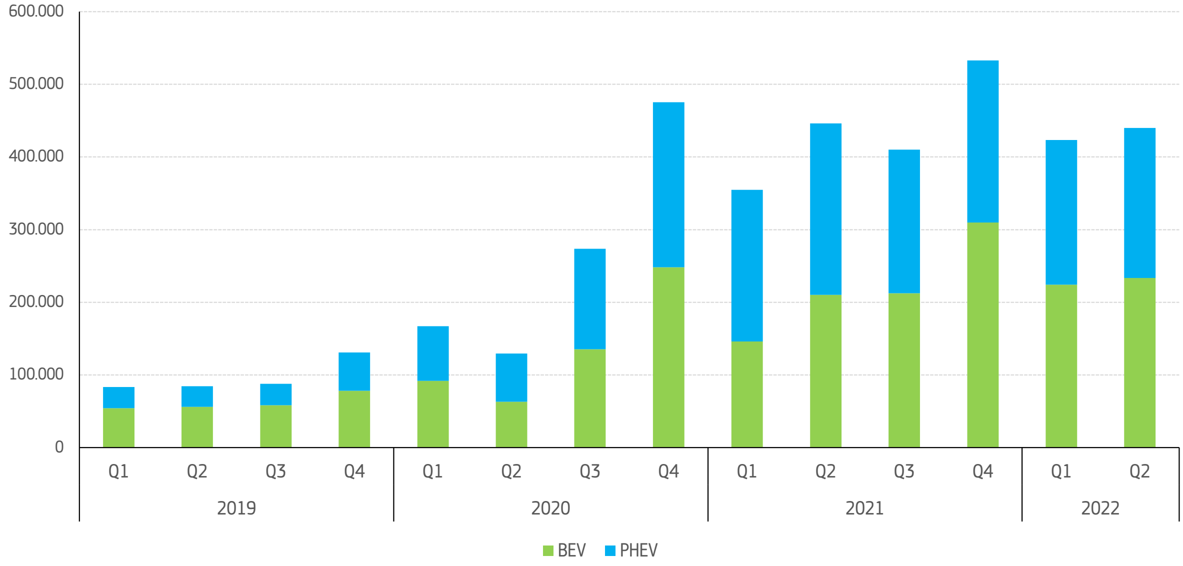
Figure 5 – Electrically chargeable passenger vehicle (ECV) sales in selected countries in Q1 2022



Source: ACEA, CPCA, BloombergNEF

- **Figure 6** shows how the rapid expansion of electric vehicles in Europe unfolded in 2021 and keeps track in 2022. Policy support, additional stimulus measures, and the economic recovery in activity following the pandemic peak, have contributed to the increase in ECV numbers. However, the demand and constraints in the supply chain of batteries might slow down the development in the near future. 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 network load.

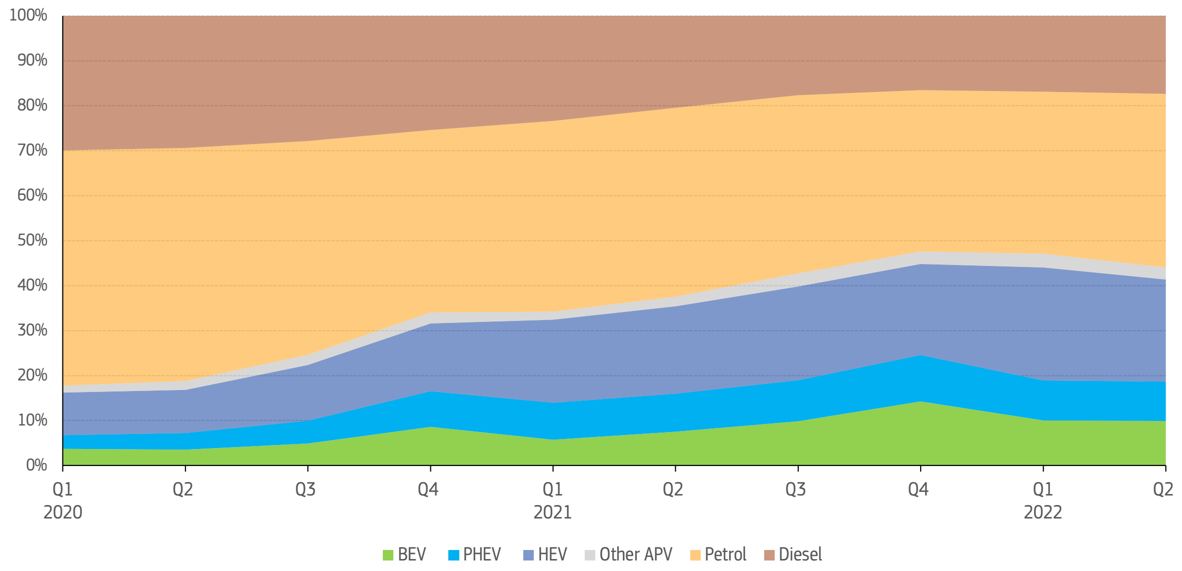
Figure 6 – Quarterly ECV sales in the EU



Source: ACEA

- **Figure 7** shows the decline of sales of diesel cars, which saw their market share fall to 17% in Q2 2022, from 20% in Q2 2021. Petrol car sales experienced a fall in their share to 39% in Q2 2022, from 42% in the second quarter of the previous year. On the other hand, the share of new Hybrid electric vehicles (HEV) in the market increased from 19% in Q2 2021, to 23% in Q2 2022. The share of new ECVs has also risen year-on-year (from 16% in Q2 2021 to 19% in Q2 2022).

Figure 7 – Evolution of quarterly drivetrain shares in the EU



Source: ACEA

1.2 Supply side factors

- **Figure 9** reports on developments in European coal and gas prices. In Q2 2022, prices of coal and gas remained at high levels and subject to volatility in the spot market, way above their year-ahead peers. The already tight global supply situation was aggravated by the Russian invasion in Ukraine and related international sanctions (including reluctance from companies to purchase Russian fossil fuels) which affected energy markets resulting in substantial increases in prices, volatility and uncertainty on energy.

- The worsening of the geopolitical picture has had a direct impact on the gas market. The drop in flows of Russian pipeline gas to Europe heavily impacted the market. The fall in inland flows registered after the announcement of the reduction of Nord Stream capacities by Gazprom in mid-June had a substantial impact on gas prices at the TTF. Gazprom started to gradually reduce gas supply on Nord Stream 1, falling to zero by September. Moreover, other international developments such as a fire at an important LNG facility in the US and a strike in Norway contributed to put upward pressure on top of the situation with Russian gas flows. Despite the geopolitical events, gas storage levels were at 56% of total EU capacity at the end of Q2 2022, at a higher level than in 2021.

- In May, the European Commission adopted a follow up Communication on the REPowerEU plan to make Europe independent from Russian fossil fuels well before 2030, starting with gas. Moreover, in July, the Commission issued a package of voluntary reduction in gas consumption to take place in the coming winter period (August 2022 – March 2023) with the target to reduce gas consumption by 15%, compared with the average winter gas consumption of the previous 5 years.

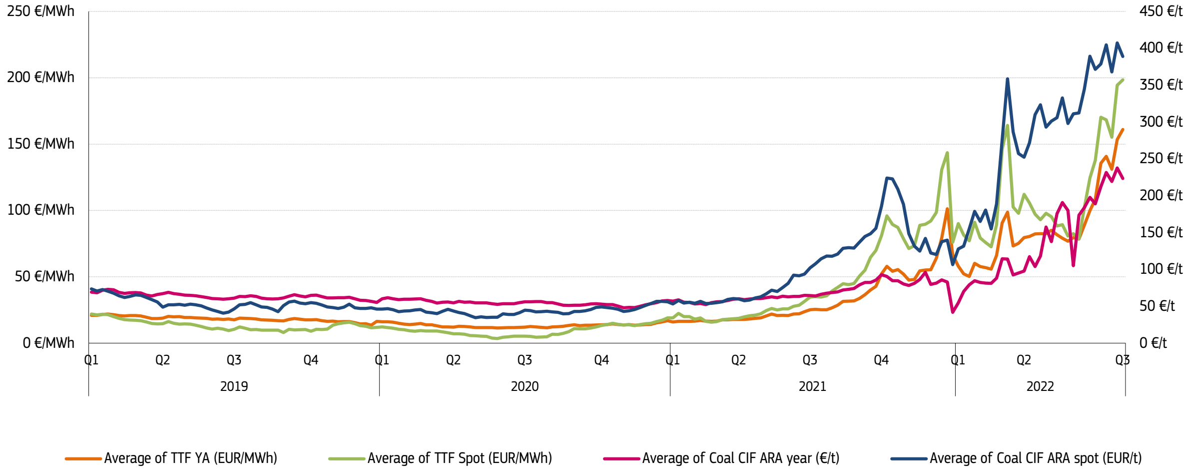
- Spot gas prices averaged 98 €/MWh in Q2 2022. Overall, prices remained unchanged compared with the previous quarter (Q1 2022) and amounted for a 287% increase compared with Q2 2021, which reflects the unprecedented level of tightness of the gas market. On 30 June, gas prices closed at 145€/MWh reflecting the uncertainties on the market as a result of the cut in flows from Nord Stream and the overall tight supply situation. On 27 July, Gazprom announced the reduction of gas flows to 20% of the capacity. In addition, on 19 August, Gazprom confirmed the maintenance of the Nord Stream pipeline, halting all flows between 31 August and 2 September. As result, wholesale gas prices underwent a tremendous increase during the summer, at the height of storage refilling season. Gas prices skyrocketed to new all-time highs in August, reaching 316 €/MWh on 26 August, due to uncertainty of gas supply via Nord Stream on top of other announcements related to maintenance in Norwegian gas assets.

- The evolution of gas prices in Q2 2022 continued to support the gas-to-coal switching observed in the previous quarters, boosting coal generation gains despite rising coal and relatively high carbon prices. Gas prices have a significant influence on electricity wholesale prices, as gas-fired generation commonly sets the wholesale electricity marginal prices in many markets of the region.

- Thermal coal spot prices, represented by the CIF ARA contract, reached a new peak in Q2 2022, where prices surged up to 411 €/t on 23 June 2022, on the back of tight global energy markets, supply diversification efforts from Russian coal and further gas-to-coal switch in international and European markets. It is important to note that Russia is the third largest exporter of thermal coal to the global market and historically, the most relevant exporter of coal to Europe. In April, the EU adopted a new round of sanctions against Russia, prohibiting imports of coal, solid fossil fuels and a range of industrial goods from Russia. As a result of sanctions, imports of coal from Russia halted since 10 August, but suppliers were already looking for alternative sources to replace Russian coal in the previous months. Moreover, prices could rise even further, as a result of increasing demand for coal in power generation in the upcoming winter period. In June, the announcements of some Member States (DE, NL, AT) to use more coal for producing electricity to replace Russian gas used for power generation rose expectations for coal prices. The German government is returning 10 GW of coal-fired reserve plants online as a way to cut dependence on Russian natural gas. Similarly, Austria is bringing one coal-fired power plant online. Likewise, the Netherlands government lifted on 20 June the production restrictions for coal-fired generation, as part of the country's gas crisis plan.

- Coal prices kept rising reaching new record highs at the end of July and August (average at 309 €/t) due to the strong demand in European and Asian markets, and supply constraints in the global market. Coal prices registered a new peak on 28 July at 425 €/t as a result of a tight global market driven by the coal demand in Asian markets for power generation.

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 10,** registered high levels of price volatility in Q2 2022. After falling in early March, carbon prices bounced back to prices around 80-85 €/tCO2 during Q2 2022. Carbon prices reached a level of 91 €/tCO2 in mid-May, still lower than the historical peak of 8 February 2022, when the closing price climbed above 96 €/tCO2 for the first time. Elevated gas prices have contributed to rise carbon prices as they lead to an increased use of coal for power generation and consequently higher demand for emission allowances. However, the curbed levels of industrial demand due to high energy prices are putting downward pressure on carbon prices. The interaction between these factors has contributed to the decoupling between EU ETS and TTF price observed in previous quarters. Prices remained highly volatile in the following months, hovering around 70-90 €/tCO2, supported by increased coal-fired generation, but limited by industrial demand destruction.

- The average spot price of CO2 in Q2 2022 (83 €/tCO2) registered an increase of 67% compared with Q2 2021, remaining relatively stable in relation to Q1 2021 (+1% increase). Under the current situation of exceptionally high gas prices, the European Union Allowances (EUA) price is not high enough to support coal-to-gas fuel switching in power generation (see **Figure 21**). In recent years (2020) high carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. Nevertheless, elevated coal prices registered at the end of Q2 2022 closed the cost gap between coal and gas generation, until gas prices rose again to new all-time records.

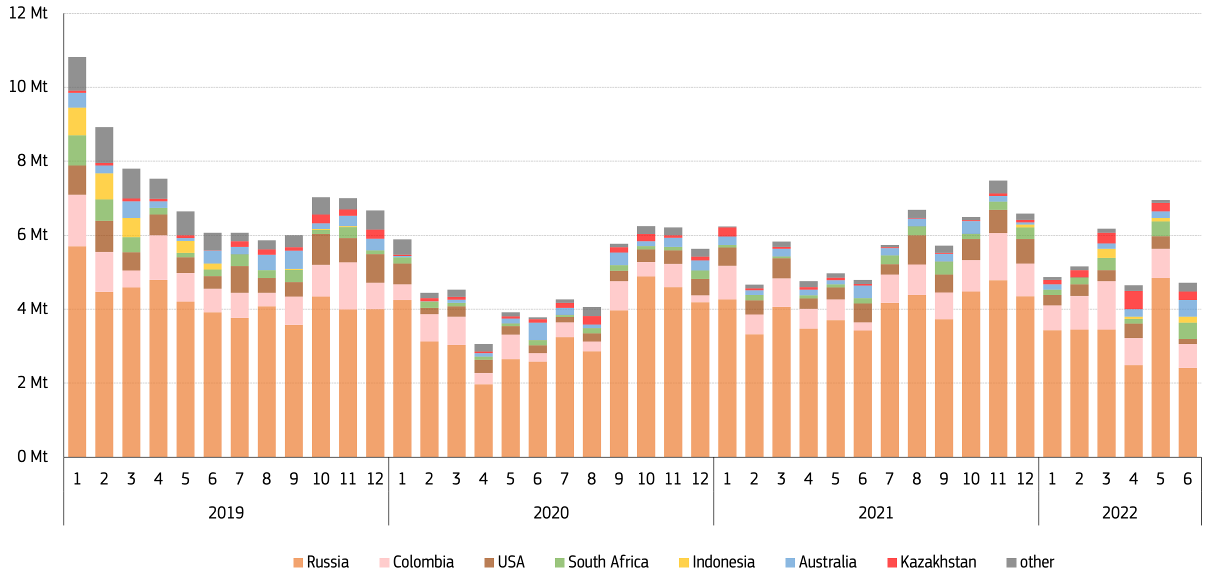
Figure 9 – Evolution of emission allowance spot prices from 2019

Source: S&P Global Platts

- As visible from **Figure 11**, monthly average thermal coal imports into the EU held at roughly 5.4 Mt in Q2 2022, as high gas prices made more space for coal-fired generation in the mix. The total volume of imports increased by 12% year-on-year to 16 Mt in the second quarter of 2022. The estimated EU import bill for thermal coal amounted to €4.6 billion in the reference quarter, 295% higher compared to Q2 2021, enhancing the year-on-year increase in imported volumes due to higher contracted prices of this commodity.

- The largest part of extra-EU thermal coal imports in Q2 2022 came from Russia which accounted for 60% of the total. Russian traders managed to achieve the highest share of the market, despite a significant decrease in the share (-13%) with respect to Q2 2021. The invasion of Russia in Ukraine in late February is already changing the shares of coal imports, as traders were already seeking alternative suppliers to Russian commodities, even before the formal sanctions. Moreover, the 5th package of sanctions adopted by the EU banned the purchase, import, or transfer of coal and other solid fossil fuels into the EU from Russia as from August 2022. This is estimated to have an impact over one fourth of all Russian coal exports, amounting to around €8 billion loss of revenue per year for Russia. The current events would act as a game-changer in the distribution of EU coal imports, as for many international competitors it was too difficult to compete in the past in a low-price/low-demand environment. Kazakhstan registered an increase of 5% of deliveries in Q2 2021 (6% of the total imports), while Colombia saw its market share growing by 4 percentage points compared to 9% in the second quarter of 2021. The share of deliveries from US ports decreased from 8% to 5%. The position of South Africa rose from 2% to 6% in Q2 2022.

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

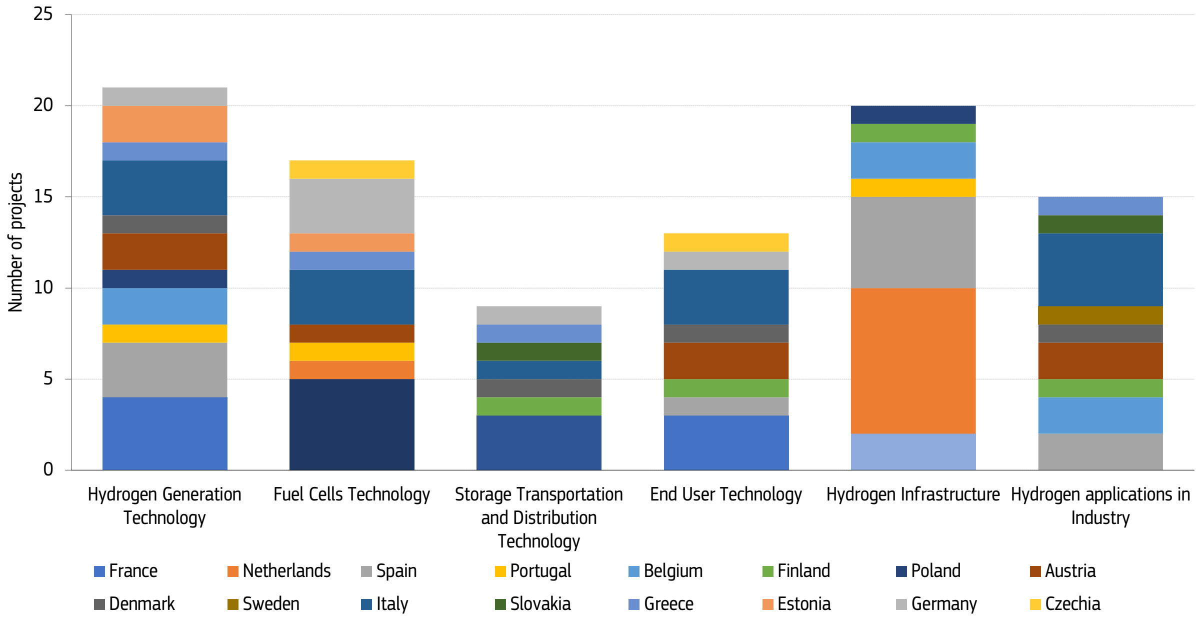


Source: Eurostat

- **Figure 12** presents the number of Important Project of Common European Interest (IPCEI) from different Member States that have received public support under EU State Aid rules in the context of projects called IPCEI Hy2Tech and IPCEI Hy2Use to support innovation, first industrial development and construction of relevant infrastructure in the hydrogen technology value chain. In total, the Commission approved up to €10.6 billion in public funding (€5.4 billion in July and €5.2 billion in September). Several projects are expected to be implemented in the near future, with various large-scale electrolysers expected to be operational by 2024-2026 and many of the innovative technologies deployed by 2026-2027.

- The EU Hydrogen Strategy adopted in 2020, put forward the main guidelines to establish a European hydrogen ecosystem to scale up production. With the publication of the REPowerEU Plan in May 2022, the European Commission outlined a 'Hydrogen accelerator' concept to scale up the deployment of renewable hydrogen. The aim of the plan is to produce ten million tonnes and import ten million tonnes of renewable hydrogen in the EU by 2030.

Figure 11 – Approved public support in the form of State Aid for Important Project of Common European Interest in the hydrogen technology value chain



Source: European Commission

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page (**Figure 13**) shows average day-ahead wholesale electricity prices across Europe in Q2 2022. In Q2 2022, prices continued at high levels across Europe, due to the impact of Russia's unprovoked invasion against Ukraine, high energy commodity prices (mainly gas, but also coal), reduced flows of pipeline gas and the uncertainty of the markets around European security of gas supply. In general, in the EU, the lower availability of the nuclear fleet and the weak hydroelectric power production due to droughts put additional pressure on wholesale electricity markets. The wholesale electricity market has continued reacting to announcements impacting the price of gas in Europe, related to the uncertainty of gas supplies from Russia, and policy responses from the EU and its Member States.

- On a yearly basis, practically every wholesale electricity market in Europe experienced a considerable surge in prices (changes ranged from approximately 100% to more than 250%[1]). Malta and Italy reported the highest quarterly average price (252 and 249 €/MWh, respectively), 211% and 234 higher than in Q2 2021. Greece became the third most expensive market with an average baseload price of 237 €/MWh, which was 238% higher compared to the same period last year. France and Switzerland reported prices of 226 €/MWh, while Slovenia registered quarterly prices of 214 €/MWh.

- The European Power Benchmark averaged 191 €/MWh in Q2 2022, 181% higher on yearly basis. Compared to Q1 2022, the quarterly average price fell by 5%.

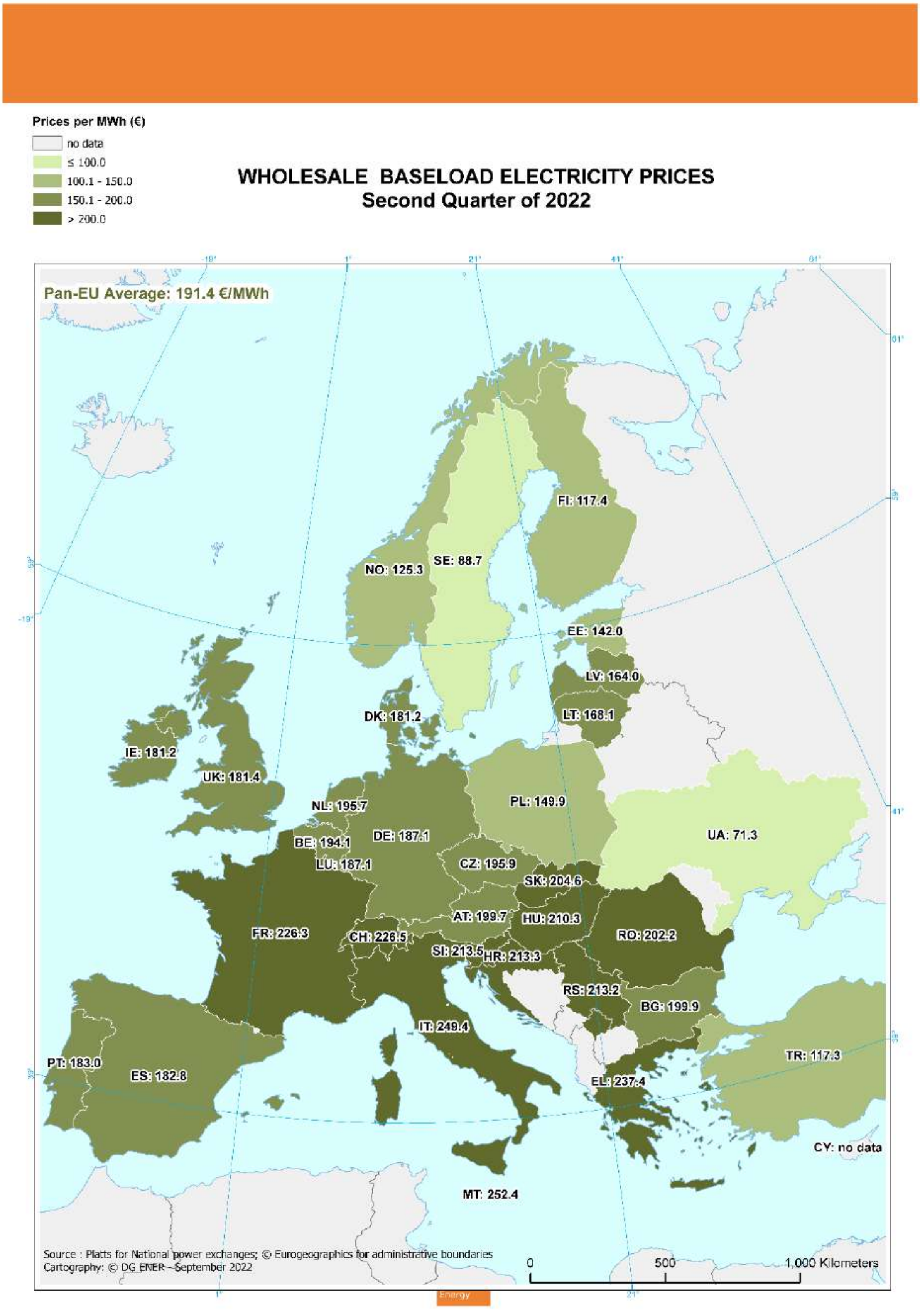
- The largest year-on-year price increases in Member States were registered in France (+254%), Greece (238%), and Italy (+234%). Prices in France were influenced by the subdued nuclear output and the reversal of net export power flows in the context of high gas prices. Conversely, Ireland experienced the lowest increase in prices during Q2 2022 (+96%) followed by Sweden (+114%).

- On 18 May 2022, the Commission adopted the REPowerEU plan to rapidly reduce dependence on Russian fossil fuels and fast-forward the green transition. To quickly diversify from Russian fossil fuels, REPowerEU plan proposes actions for three parallel priorities tackling both short-term and long-term dependency challenges: saving energy, accelerating clean energy production and diversifying EU energy supplies. The Commission also adopted the communication on Short-Term Energy Market Interventions and Long-Term Improvements to the Electricity Market Design, with additional short-term measures to tackle high energy prices and address supply disruptions from Russia. It also presented a number of areas where the electricity market can be optimised, built on the ACER's Final Assessment of the EU Wholesale Electricity Market Design.

- On 14 September 2022, the Commission proposed new emergency market intervention measures to address high energy prices in Europe. The package of measures included exceptional electricity demand reduction measures and measures to redistribute the energy sector's surplus revenues to final costumers. The Commissions continues its work to improve liquidity for energy market operators, bring down the price of gas and reform the electricity market design for the longer term.

[1] Sixteen EU MS experienced increases over 200% and nine above 100%, compared to Q2 2021.

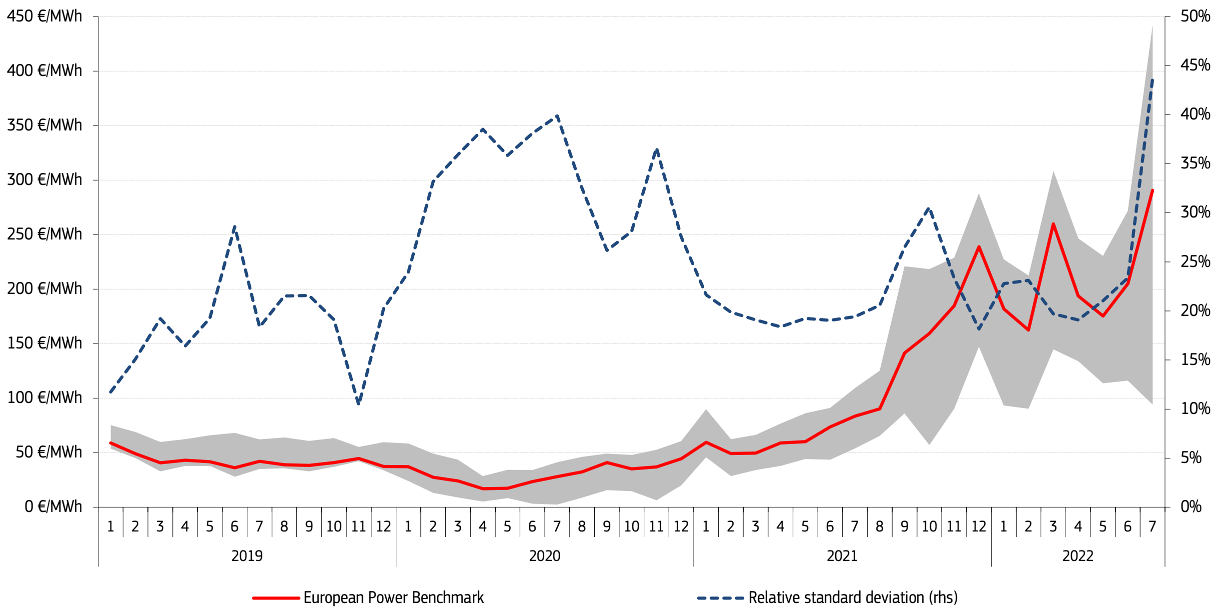
Figure 12 – Comparison of average wholesale baseload electricity prices, second quarter of 2022



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 14** shows the European Power Benchmark of nine markets, including the lowest and highest regional prices in Europe represented by the two boundary lines of the shaded area, as well as the relative standard deviation of regional prices. The relative standard deviation metric shows that divergence levels have recently started to increase, after a short period of relatively stability, as prices in the regional markets started to diverge again in Q2 2022. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. In July 2022, some member states (Austria, Germany, Italy and the Netherlands) announced plans to temporarily increase coal-fired power generation, with the aim of saving gas and boosting gas storage filling in the summer. The lower availability of the French nuclear fleet is putting upward pressure on prices and reversing power flows away from the historical net exporting position of France. The Nordic region experienced dry weather conditions reducing hydropower output, which combined with the tightness of the continental European markets, resulted in an increase in prices. Soaring gas prices in Italy, combined with tight supply margins, made Italy the second most expensive market in Europe (after Malta). During Q2 2022, The wholesale electricity market reacted to announcements impacting the price of gas in Europe, due to the reduction of gas supplies from Russian pipelines and by policy responses from the EU and its Member States. In the summer, prices reached new all-time peaks at the end of August, as a result of further disruptions of Russian gas supplies, increased demand due to record-breaking temperatures, maintenance of power stations (in particular nuclear) and lower output from hydropower generation.

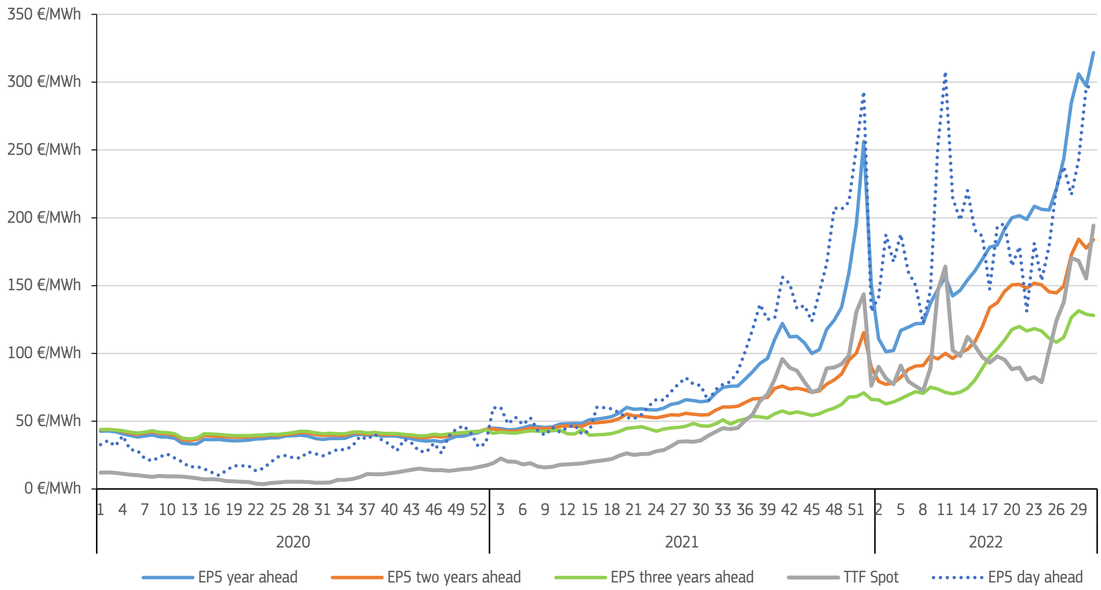
Figure 13 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- **Figure 15**, shows the effect of gas prices (TTF spot price) driving changing expectations of future electricity prices since the first quarter of 2021. The rally in gas prices that started in 2021, lifted the benchmark above pre-crisis levels and into record highs. After a peak in March, the TTF spot price started climbing again in June, reaching an average value of 138 €/MWh during the last week of June. Consequently, the year ahead power benchmark rose to very high values at the end of Q2 2022. From that point, year ahead power benchmark prices continued the rally reflecting the limited supplies of gas from Russia and outages in other relevant gas suppliers to Europe. New historical peaks were reached during summer, were future contracts surged, reaching 727 €/MWh on the year-ahead benchmark during 26 August. During the same day, the year-ahead contract of France skyrocketed to 1130 €/MWh.
- During the first week of Q2 2022, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 161 €/MWh, 108 €/MWh and 80 €/MWh, whereas during the last week of June, these three values reached weekly highs of 243 €/MWh, 150 €/MWh and 112 €/MWh. The significant increase of forward curves in Q2 2022 and beyond, suggests the market does not anticipate a quick return to lower price levels. The discount of the year-ahead contract to the spot market oscillated between -6 €/MWh and 29 €/MWh during Q2 2022.

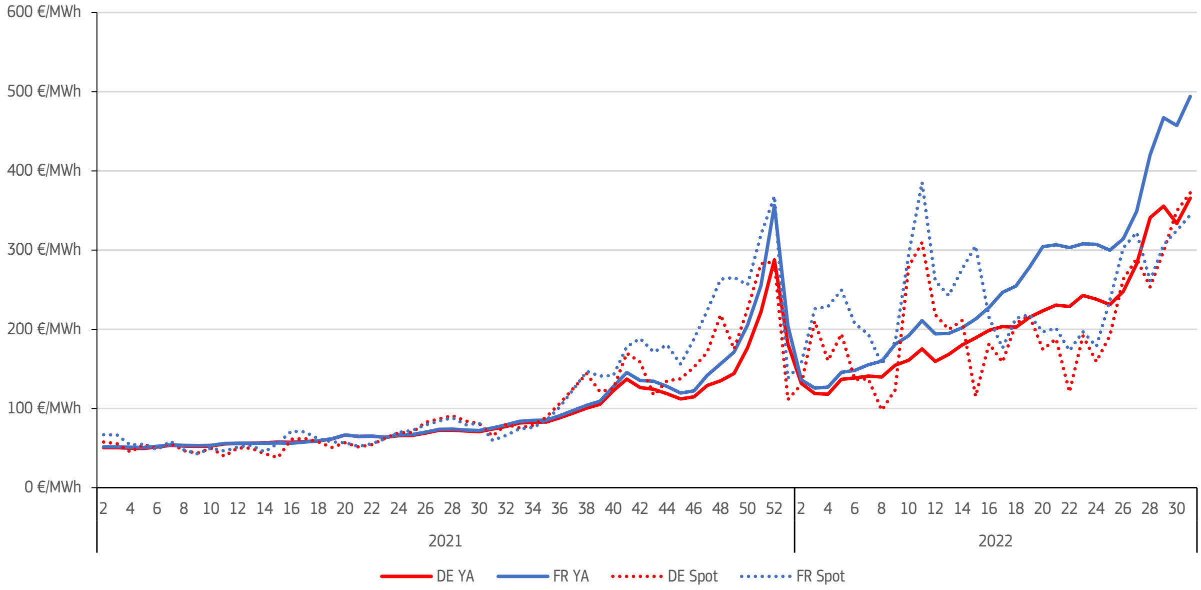
Figure 14 – Weekly futures baseload prices – weighted average of selected European markets



Source: S&P Global Platts.

- **Figure 16** shows the evolution of year-ahead contracts of Germany and France, together with their equivalent spot (day-ahead) prices. The divergence between the two forward contracts has been increasing since the beginning of the year, reflecting structural differences between the two markets (i.e. the high proportion of French nuclear power plants under maintenance and the high levels of wind generation that cover a significant part of the demand at times in Germany). The French premium over the German forward contract reflects worries over the availability of the French nuclear fleet. The premium of the French contract over their German equivalent contract started at 23 €/MWh in the first week of the reference quarter and it reached 66 €/MWh during the last week of June. The gap kept increasing, registering a premium of 128 €/MWh in the last week of July, over their equivalent German year ahead contract.

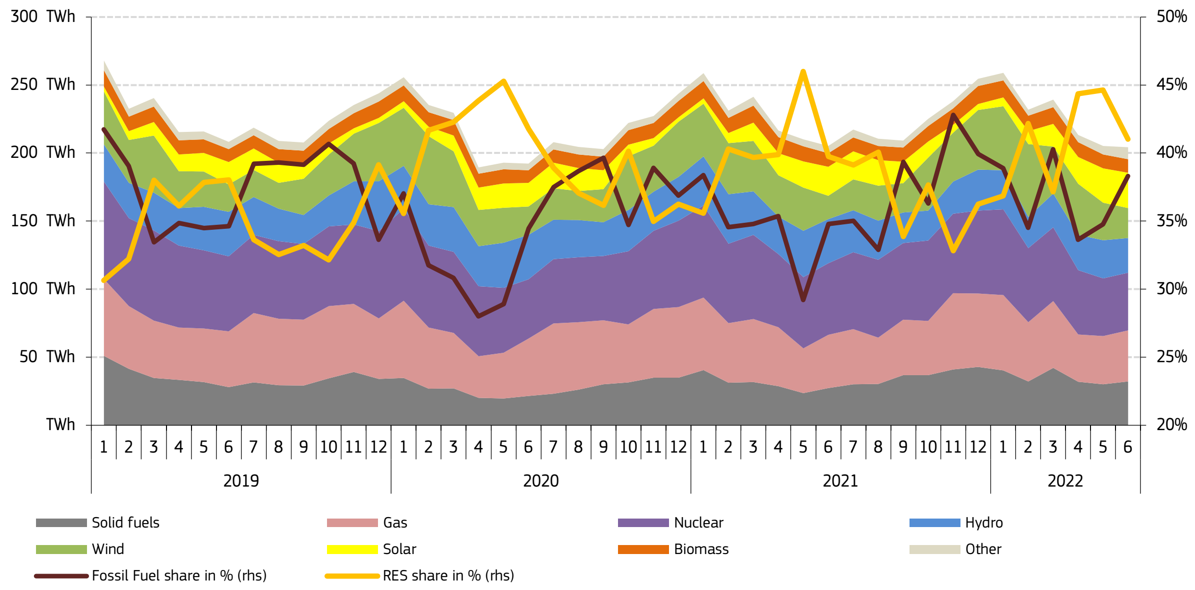
Figure 15 – Weekly German and French year ahead contracts



Source: S&P Global Platts.

- **Figure 17** shows the monthly evolution of the electricity mix in the EU. As a result of decreased nuclear and hydro generation during Q2 2022, fossil fuels were able to increase their level of generation in the mix. The share of electricity generated by burning coal, gas and oil (fossil fuel generation) reached 36% in Q2 2022 (from 33% in Q2 2021). Nevertheless, renewables manage to increase their share to 43% (from 42% in Q2 2021). Nuclear generation remained another quarter under pressure, due to unplanned outages and scheduled maintenance in France, decreasing its share of generation in Q2 2022 to 21% (from 25% in Q2 2022). Nuclear output fell by 17% (-27 TWh) in Q2 2022.
- Within the fossil fuels realm, coal gained ground both in absolute and relative terms compared to Q2 2021, mainly as a reaction to the rally of gas prices which reversed the coal-to-gas switch registered in 2020, despite relatively high carbon prices. Overall, fossil fuel generation registered an increase of 12 TWh y-o-y (+6%). Coal's share in the mix rose to 15%, whereas less CO2-intensive gas generation fell slightly at 17% in the reference quarter. In absolute terms, coal-based generation rose by 15 TWh year-on-year (+19%), while gas-fired power plants' output fell by 8 TWh (-7%). Renewables generated 5 TWh more of electricity year-on-year on the back of improved solar and wind generation, despite low levels of hydro output.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 17**), lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current level of CO2 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 67% more expensive in Q2 2022 compared to Q2 2021, although rising gas and hard coal prices were able to counterweight the effect of high carbon prices. In the end, lignite-based generation in Q2 2022 rose by 20% year-on-year (more than 8 TWh) and hard coal-fired generation increased by 17% year-on-year (6 TWh).

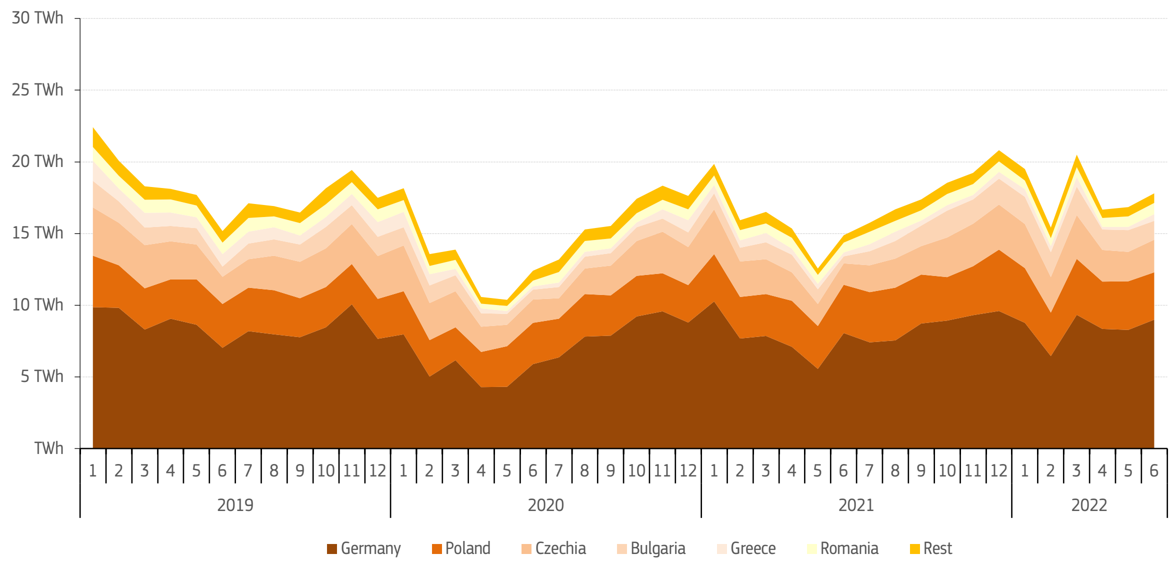
Figure 16 – Monthly electricity generation mix in the EU



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

- **Figure 18** shows the comeback of lignite generation after the covid-related drop during 2020, helped by soaring gas and hard-coal prices (which decreased the competitive edge of gas- and hard coal-fired power plants). Most Member States with remaining lignite-fired capacity increased its output during Q2 2022 (Greece being the exception). Monthly output peaked in June at roughly 18 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel rose by 24% year-on-year in Q2 2022, potentially due to the impact of high gas prices (i.e. gas-to-lignite switching) combined with the scheduled reduced nuclear capacity. Lignite-fired generation in Poland increased by 5% year-on-year in Q2 2022, supported by lower gas generation. The output of the Czech lignite fleet rose by 30% year-on-year. The three Member States accounted for 82% of the total lignite-based generation in the EU in Q2 2022. In Greece, lignite generation decreased by 16% year-on-year on the back of reduced lignite capacity, increased oil-fired generation, but also improved solar and wind output, together with a slight reduction in electricity demand. In Bulgaria, decreased gas-fired and hydro output enabled the generation of additional volumes of lignite (+55%) compared to Q2 2021. Lignite power plants reached an 8% share in the EU generation mix in Q2 2022 (up from Q2 2021) and were responsible for approximately 34% of the electricity sector's total carbon emissions in the reference quarter.

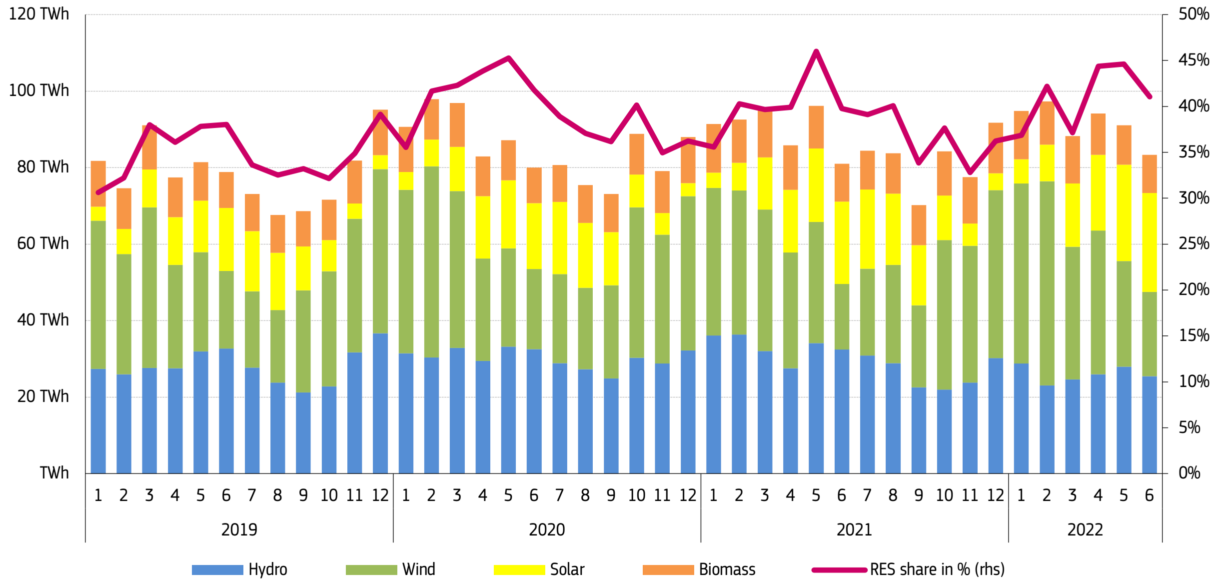
Figure 17 – Monthly generation of lignite power plants in the EU



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

- **Figure 19** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. Renewable penetration reached 43% in Q2 2022, slightly higher than the 42% share of Q2 2021, and greater than the first quarter of 2022 (38%). An increase of 5 TWh in renewable generation contributed to the growth in renewable penetration during Q2 2022.
- The main gains in renewable output came from solar (+13 TWh), wind onshore (+7 TWh), and wind offshore (+1 TWh) in comparison to the reference quarter in 2022. Thanks to an increasing capacity, solar PV generation rose by 24% in Q2 2022 to a total of 71 TWh, almost six times more than oil-fired generation. In absolute terms, the increase was mostly driven by +3 TWh in Spain (+34%) and Germany (+13%), +2 TWh in the Netherlands (+45%), and for another quarter, the impressive figures registered in Poland with an additional +1.4 TWh and a 102% increase in solar output. In addition, the share of solar generation in Spain reached 16% in Q2 2022, surpassing the share of oil (4%) and hard coal (3%).
- Thanks to the rapid development of new capacity, onshore wind gains during the reference quarter (+10%) were reported mainly by +2 TWh in Sweden (+34%) and in Spain (+13%). Conversely, France registered calm weather, which resulted in a decline of wind generation by 10%. Offshore wind gains (+11%) during Q2 2022 were reported mainly by +0.5 TWh in Germany (+11%). Overall, wind output remained with a surplus (+8 TWh) in Q2 2022, increasing its generation by 10%.
- However, for another quarter, the brunt of the losses in renewable generation came from hydro (-15 TWh), falling by 16% during Q2 2022. Main hydro generation volume losses were registered in Italy (- 5 TWh), France, Spain and Romania (- 2 TWh) as a result of low stock levels and limited precipitations. Bulgaria, Croatia, Czechia, Germany, Finland, Hungary, Greece, Ireland, Lithuania, Latvia, the Netherlands, Portugal, Romania, Sweden, Slovenia and Slovakia also registered declines in hydro generation compared to Q2 2021.

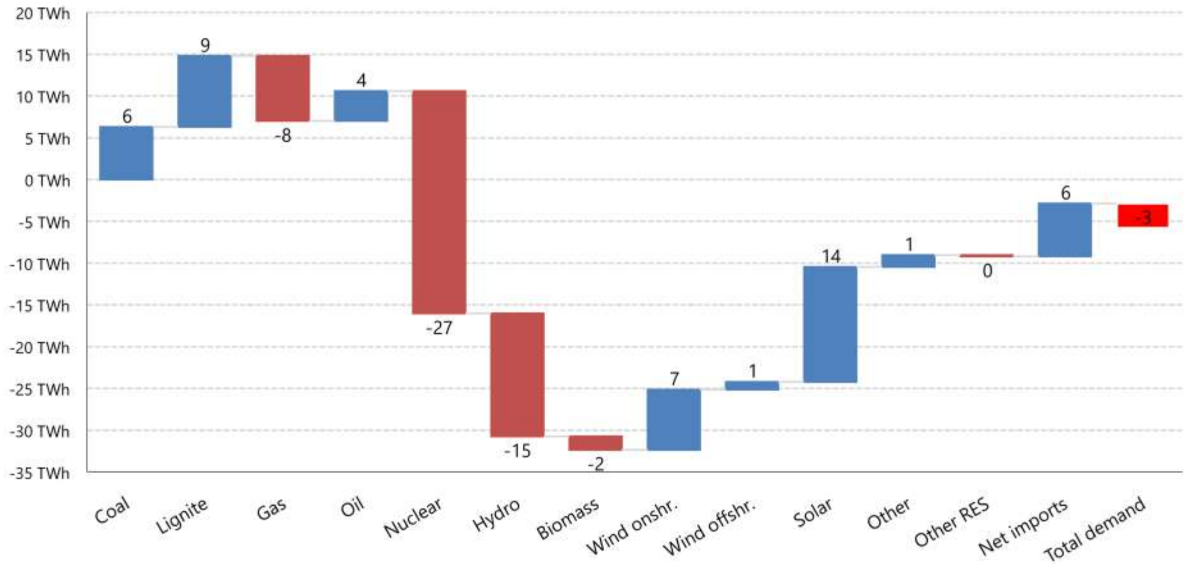
Figure 18 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- **Figure 20** visualises changes in the EU27 electricity generation, imports and consumption in the reference quarter (Q2 2022) compared to Q1 2021. The space for conventional power plants' running hours was augmented, following the trend of previous quarter. Fossil fuels boosted their generation by +12 TWh. Renewable sources generation rose (+5 TWh), despite significant falls in hydro generation (-15 TWh). Net imports rose (+6 TWh) compared to Q2 2021. Nuclear generation registered a large drop (-27 TWh) due to reduced fleet availability and phase out policies in key Member States. All in all, hard coal increased its output by 6 TWh, lignite by 9 TWh, whereas gas-fired generation fell by 8 TWh, due to the skyrocketing commodity prices. Oil generation rose (+4 TWh) compared to Q2 2021, stretching the availability of fuel switch for power generation. Based on preliminary estimates, the carbon footprint of the power sector in the EU rose by 10% year-on-year in Q2 2022, due to a larger use of more carbon-intensive fossil fuels. However, emissions were still 1% lower than 2019 levels (Q2 2019). If the current trend continues, it is likely that both the power sector's carbon footprint and carbon intensity will rise in 2022.

Figure 19 – Changes in power generation in the EU between Q2 2021 and Q2 2022

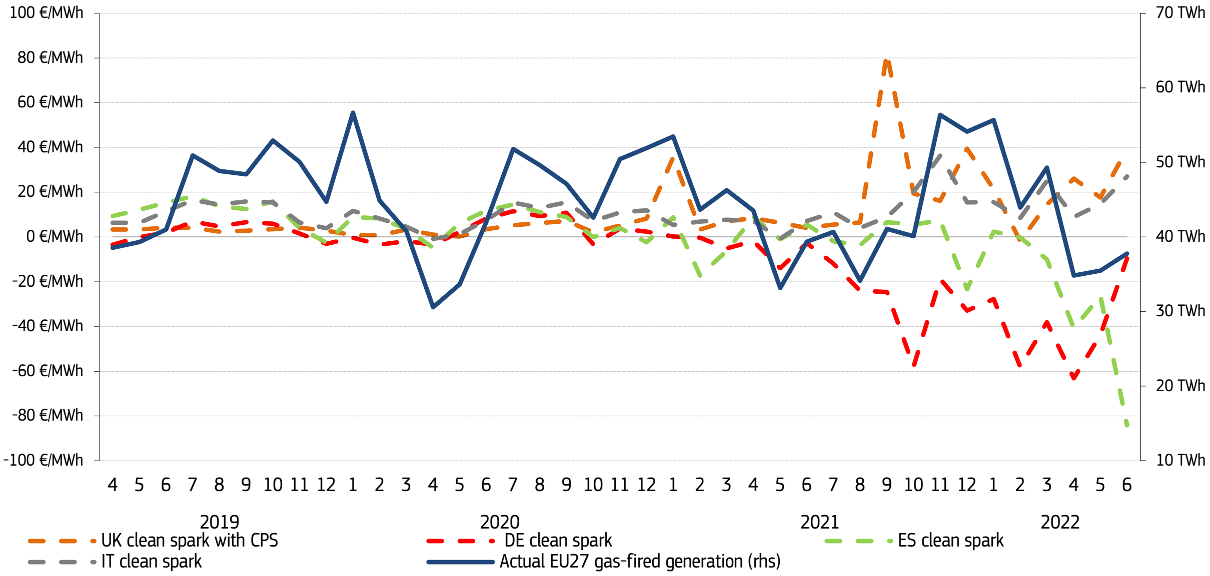


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation

- 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 spread indicators. As a result of the rally in coal prices, coal-fired generators experienced additional pressure to remain in the profitability zone compared with gas-fired plants. Unlike previous quarters, rising coal prices have also impacted on the profitability of coal-fired power plants, reducing the competitive advantage to gas they have enjoyed in the last quarters. However, high prices created health margins for gas and coal generators in some markets, as the Italian and German clean dark spreads remained on average into the positive area during Q2 2022. Likewise, clean spark spreads remained at positive levels in the case of UK and Italy. Coal usage has been increasing to compensate for high gas prices and subdued hydro and nuclear generation in Europe. However, despite low levels of profitability for gas-fired generation compared to coal-fired generation, the fuel switching capacity is limited by the scarcity of coal-fired plants still in operation, resulting from the decommissioning of the fleet over the last years.

- As shown in **Figure 21,** the profitability of gas firing for electricity generation remained mostly in positive territory for a plant with an average efficiency during Q2 2022 in the UK and Italy. The positive profitability levels of gas-fired generation in Italy are likely due to much higher wholesale electricity prices. In Germany, the profitability of gas-fired generation fell sharply, due to an increase in gas prices that have outpaced the rise in wholesale electricity prices. Conversely, the Spanish equivalent registered a drop accentuated in June. In Spain, the steep fall in profitability in Q2 2022 might also have been related to the impact of the 'Iberian exception', that subsidises gas-fired generation. German clean spark spreads have not been in positive territory since January 2021. In June, the UK clean spark climbed to 39 €/MWh. The highest clean spark spreads in Q2 2022 were assessed in the UK (28 €/MWh), followed by Italy (17 €/MWh). The lowest was presented in Spain (-50 €/MWh), registering a minimum of -84 €/MWh in June. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU gas generation reached 108 TWh in the reference quarter, down by 7% compared to Q2 2021.

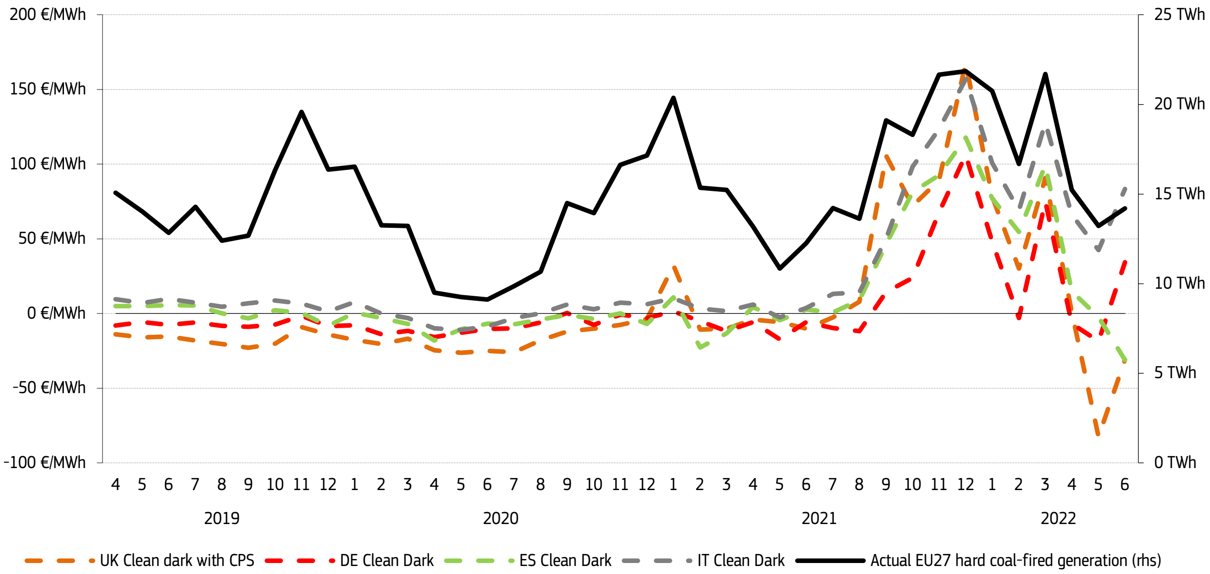
Figure 20 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 22** shows that Italy, followed by Germany, experienced the most profitable coal-fired power generation in Q2 2022. In May, most of the selected markets presented lows in the profitability indicator for an average plant, as a result of rising coal prices, combined with a temporary ease in the rally of gas prices. Clean dark spreads in Italy averaged 64 €/MWh in Q2 2022, more than three times than in the case of gas-fired power plants. Coal generation in Spain increased by 91% year-on-year in the second quarter of 2022, with only few units remaining in the market. German coal generators increased their output by 29% year-on-year in Q2 2022, as nuclear generation has been gradually fading in accordance with the German nuclear phase-out plan and gas-fired plants have not been running as many hours as they did in Q2 2022. However, as coal prices continue on the current rising trend, coal-fired generators may experience further pressure to remain above gas-fired generation in terms of profitability.

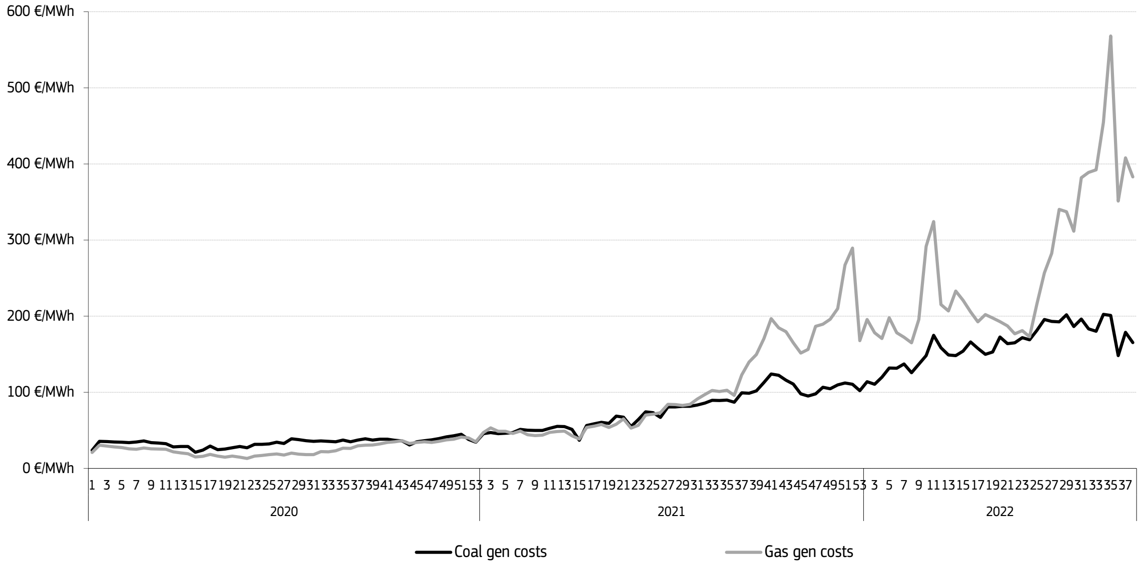
Figure 21 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 23** shows the significant impact of gas prices on gas-fired generation variable costs (fuel and emission allowances) from the second half of 2021. Under normal conditions, the elevated carbon price would have promoted fuel switching (from coal to gas) as it was the case in 2020, due to a combination of low gas prices and increasing prices of emissions allowances. However, unprecedented gas prices have had a more significant impact on gas-fired generation costs, than the increase in coal and carbon prices on coal-fired generation costs. However, elevated coal prices during May and June were able to close the gap in variable costs, briefly supporting coal-to-gas switching for the first time since July 2021. Nonetheless, skyrocketing gas prices during the summer further widened the variable generation cost gap between gas and coal.

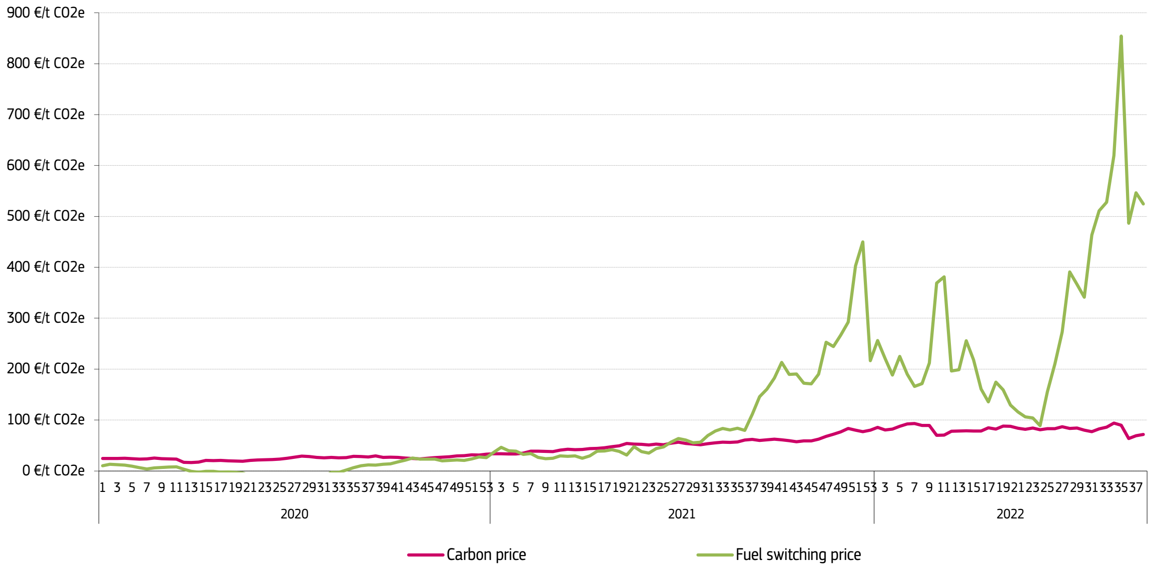
Figure 22 – Variable generation costs of coal- and gas-fired power plants



Source: S&P Platts, ENER.
Note: Thermal efficiency values used for coal- and gas-fired plants were 41% and 55% respectively. Emissions intensity values used were 0.85 and 0.37 tCO2e/MWh respectively for coal- and gas-fired generation.

- **Figure 24** shows how the supply tightening of the coal market during May and June, combined with a relative decline in gas prices briefly improved the economics of gas-fired plants for the first time in eight months. The average fuel switching price required to make gas-fired plants economically viable vis-à-vis coal fell to 88 €/tCO2 during the third week of June, approaching to the average carbon price of 85 €/tCO2 during May. However, the fuel switching price reached an average of 600 €/tCO2 in August, registering a peak of 854 €/tCO2 during the fourth week of that month. New all-time high gas prices and the uncertainty of Russian gas supplies to Europe are contributing to increase the fuel switching price.

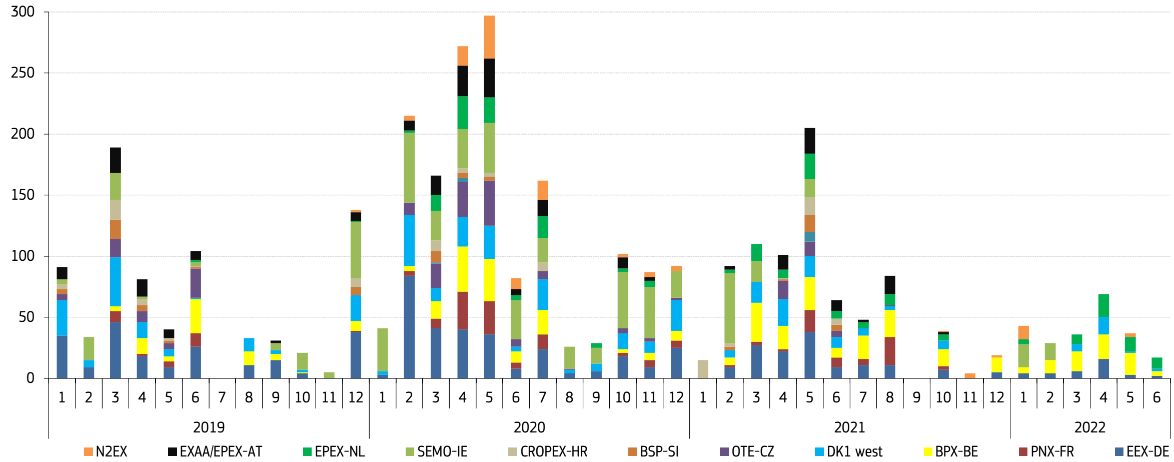
Figure 23 – Coal-to-gas fuel switching



Source: S&P Platts, ENER.

- **Figure 25** 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 variable 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 Q1 2022 (154) was 57% lower in the observed bidding zones than in the previous second quarter. Most of the falls into negative territory occurred in May of the reference quarter and took place in days when low consumption coincided with high renewable generation. The highest number of negative prices was recorded on 28 May, when strong wind speed combined with weak demand, pushed some Central Western Europe markets (German, Dutch and Belgian) and Western Denmark prices below zero during several hours of the day. Wind generation covered a large part of the Danish consumption during that day.
- Belgium recorded the highest number of negative hourly prices (59) in Q2 2022, followed closely by the Netherlands (48). Belgium recorded an increase of 9% of negative hourly prices in Q2 2022. The higher level of penetration of variable renewables has introduced new challenges to the grid balance and has accentuated the need for more flexibility in the European power system. It has also intensified the search for market instruments that would find a proper value of flexibility. Flexibility will gain more and more importance as we transition to a renewable-based energy system.

Figure 24 – Number of negative hourly wholesale prices on selected day-ahead trading platforms

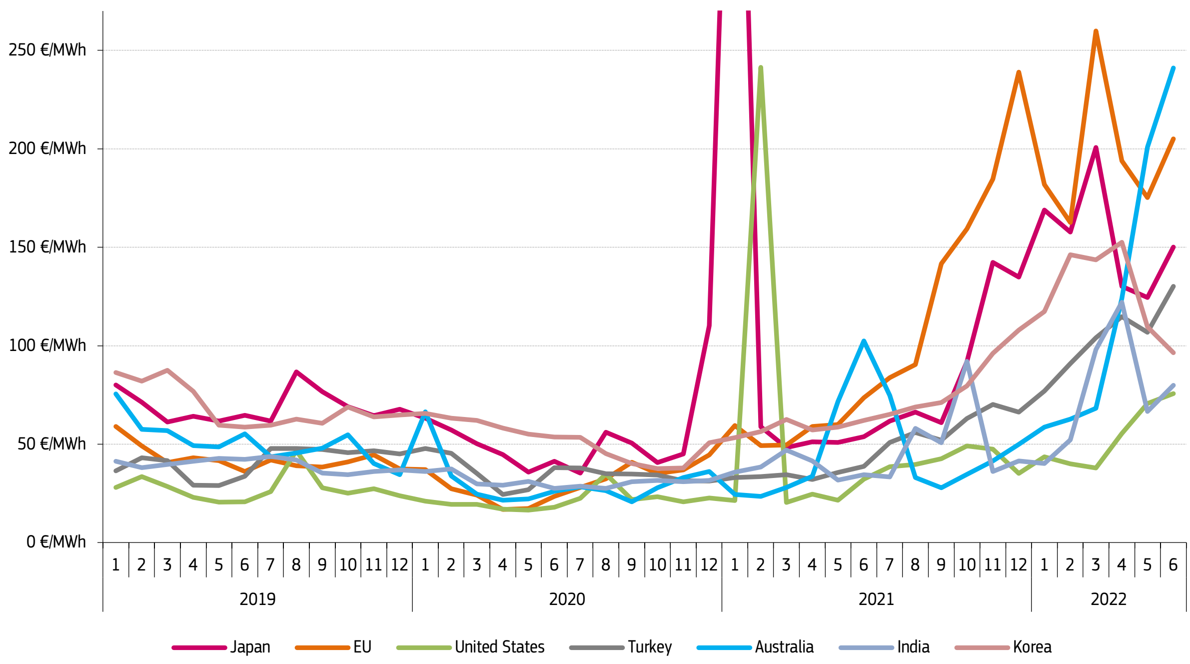


Source: Platts, ENTSO-E. For Austria, the EXAA market is used prior to October 2018, and the EPEX market is used afterwards.

- **Figure 26** compares price developments in wholesale electricity markets of selected major economies. Most markets saw prices mounting due to tight global markets, exacerbated by the global impact on commodities (mainly gas, but also coal) by the Russian war in Ukraine. In the U.S., wholesale electricity prices increased in most of the analysed regional wholesale markets. Rising natural gas prices at the U.S. Henry Hub led to high wholesale electricity prices. Moreover, warm temperatures increased electricity demand in May and June in many of the regional benchmarks. Overall, the benchmark of U.S. prices increased by 157% in Q2 2022 compared with Q2 2021. The latest edition of the [EIA's Short Term Energy Outlook (STEO)] expects the price of Henry Hub to rise during the last quarter of the 2022 and to fall in 2023 as domestic natural gas production rises. The rising prices of gas at Henry Hub will continue to put pressure on gas-fired generators as they often perform as the marginal technology to supply power.
- In Japan, higher LNG and energy commodities prices, combined with a surge in power demand due to high temperatures, contributed to a steep increase in prices during Q2 2022 (+160%). The Russian invasion to Ukraine increased the pressure on the already high LNG prices in Japan (which relies heavily on fossil-fuel power generation, and it is one of the most important LNG buyers in the global market). Rising coal and gas prices, together with potential winter temperatures could drive power prices higher during the following months. South Korea have been equally exposed to tightening LNG market fundamentals and heat waves, driving prices 102% higher in the reference quarter.
- European wholesale prices were once again, the highest of the observed economies in Q2 2022, reaching 191 €/MWh. In Australia, prices reached all-time high requiring market interventions during June 2022. In June, unprecedented high gas and coal prices, outages of coal-fired power plants, subdued renewable generation and a cold snap put the Australian electricity network under a major strain. After the trigger of safety nets (price cap), the Australian market operator suspended the market, in order to secure sufficient supply to the grid. Despite the critical

situation, the Australian operator was able to avoid any significant load shedding or blackouts in the grid. Prices were consistently higher in all the NEM regions, as Australian prices rose 172% year-on-year throughout Q2 2022. Milder weather and a drop in demand decreased pressure on power prices during the following months. Prices in India rose by 149% in Q2 2022 on the back of increased power demand due to rising economic activity and warmer-than-average temperatures. Power outages were registered across some Indian states.

Figure 25 – Monthly average wholesale electricity prices in international markets (D-A markets)



Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (the latest data for Russia is not available), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

2.2 Traded volumes and cross border flows

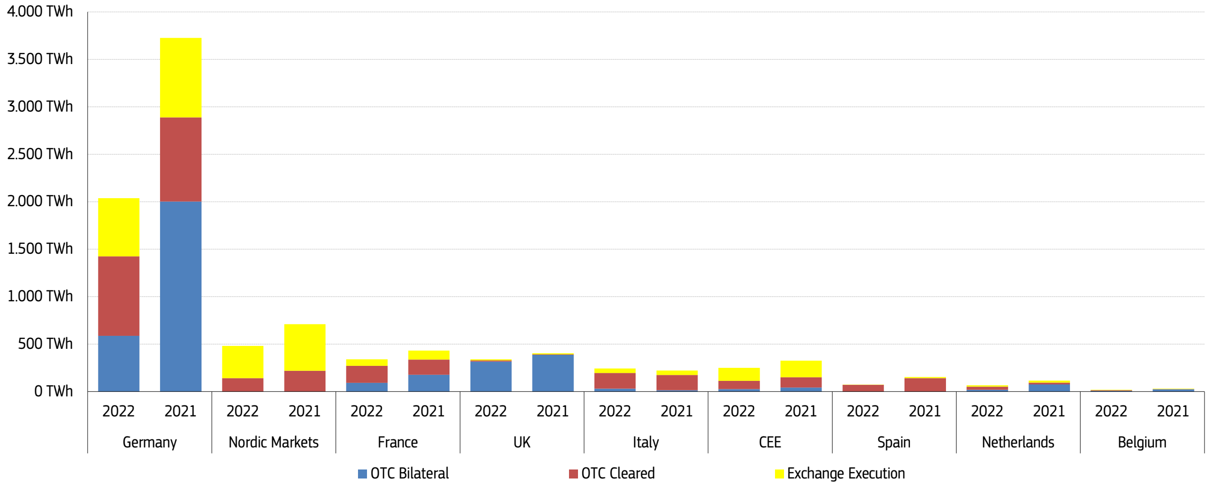
- **Figure 27** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. Most markets and regions witnessed a year-on-year decline in trading activity up to July 2022, following the trend registered during 2021. Decreased over-the-counter liquidity has been attributed to the situation of high prices and increased volatility in the energy market, while cleared exchange-based activity has also fallen, but to a lesser degree. Activity dropped significantly in OTC contracts (-41%) and decreased at exchanges (-27%) in the total traded volumes under observation during the reference period.

- The largest annual falls in total traded volumes were registered in Spain (-52%), Germany (-45%), the Netherlands (-42%) and Belgium (-38%). Losses were driven mainly by the OTC sector, especially in the case of Germany. The total traded volume in all markets under observation fell by 51% to 1425 TWh during the reference period.

- Despite falls in traded volume, Germany was by far the largest and most liquid European market, as total volumes reached 2037 TWh (equivalent to 53% of the total traded volumes under observation up to July 2022). Overall, total activity fell (-45%) in Germany in Q2 2022. In Germany, the market share of exchanges experienced an increase (+8 p.p.) and the OTC contracts share decreased (-8 p.p.) compared with year-to-date values in July 2021. Spain and the Netherlands markets registered a drop in activity of 51% and 42%, to 74 TWh and 67 TWh, respectively. Relative decreases in activity were also visible in Belgium where total volumes fell (-38%) to 20 TWh. Also, relative decreases were also visible in the CEE region where total volumes fell by 24% to 250 TWh.

- Overall, the market share of power exchanges expanded from 28% to 32%. The largest increase in exchange-based volumes were registered in the UK (+10%), while falls were reported in Spain (-71%) and the Netherlands (-37%). Overall, exchange-based trading volumes decreased by 462 TWh up to July 2022 (-10%). The OTC segment traded 1812 TWh less of electricity up to July 2022 compared with the same period in 2021, as a result of lower volumes changing hands in Germany, Spain and the Netherlands. OTC volumes reduced their share off the market to 70%. Germany, Spain, the Netherlands and Belgium registered the largest decrease in bilateral OTC deals (-51%, -50%, -42% and -38% respectively).

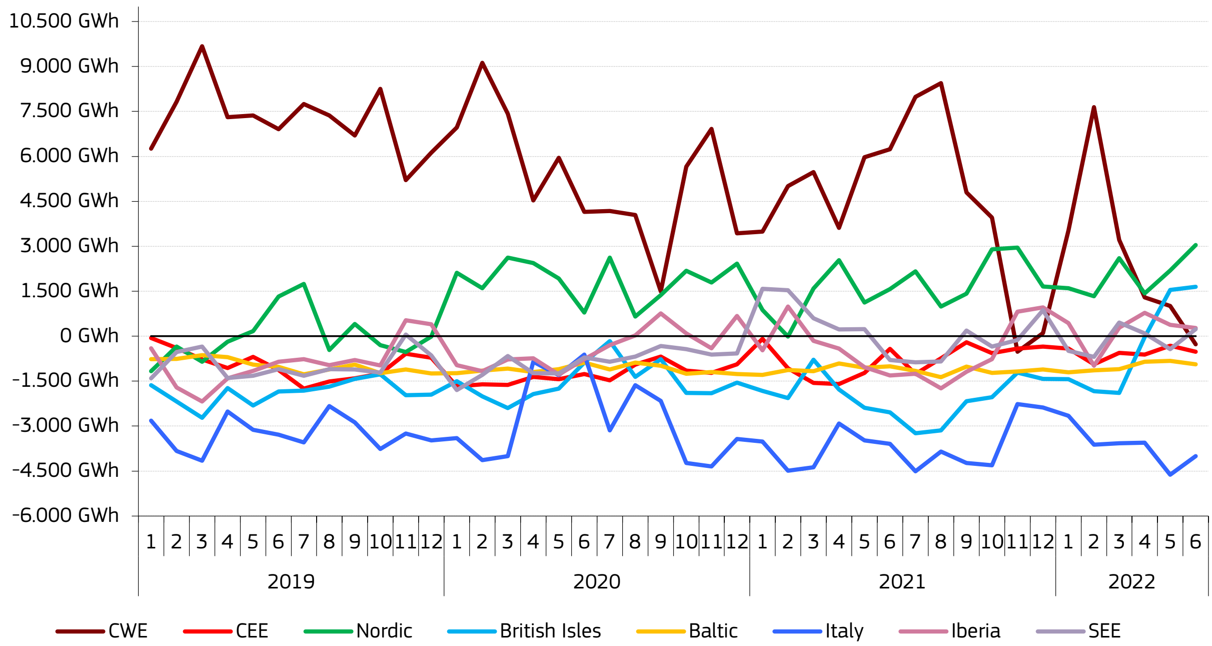
Figure 26 – Annual change in traded volume of electricity on the most liquid European markets



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

- **Figure 28** reports on the regional cross-border flows of electricity. Central Western Europe registered a drop in its traditional position as the main exporting region during Q2 2022. CWE, which has abundant and diverse generation capacities and a suitable central position to supply other regions, has traditionally been in a privileged position to act as a net exporter. However, during the second quarter of 2022, CWE registered only 2 TWh of net exports, decreasing its outflows by 87% during the quarter in comparison to Q2 2021. The drop can be traced mainly to high gas prices, lower nuclear availability in the CWE main markets (maintenance or scheduled phase-out), combined with subdued hydropower generation, which decreased the availability of exports. The Nordic region recorded a surplus of 6.6 TWh in the reference quarter, 27% above from the net exports in Q2 2021. Conversely, net flows to the British Isles changed the traditional direction (net imports) compared to Q2 2021. During Q2 2022, the British Isles recorded 3 TWh in net exports. The Iberian Peninsula also registered a change in flows, recording 1.4 TWh of net exports in Q2 2021, compared with the 2.7 TWh of net imports in Q2 2021.
- The rest of the regions ended up in deficit. This was mainly due to less available generation across the EU in general, supported by high gas prices, reduced nuclear availability and hydro output. South Eastern Europe remained for another quarter as net importer (-0.1 TWh), an improvement compared to the Q1 2021 figures (-0.3 TWh). Italian net imports increased by 22% year-on-year to -12.1 TWh in Q2 2022. The CEE region's net position (-1.4 TWh) improved by 55% in Q2 2022 compared to Q2 2021.

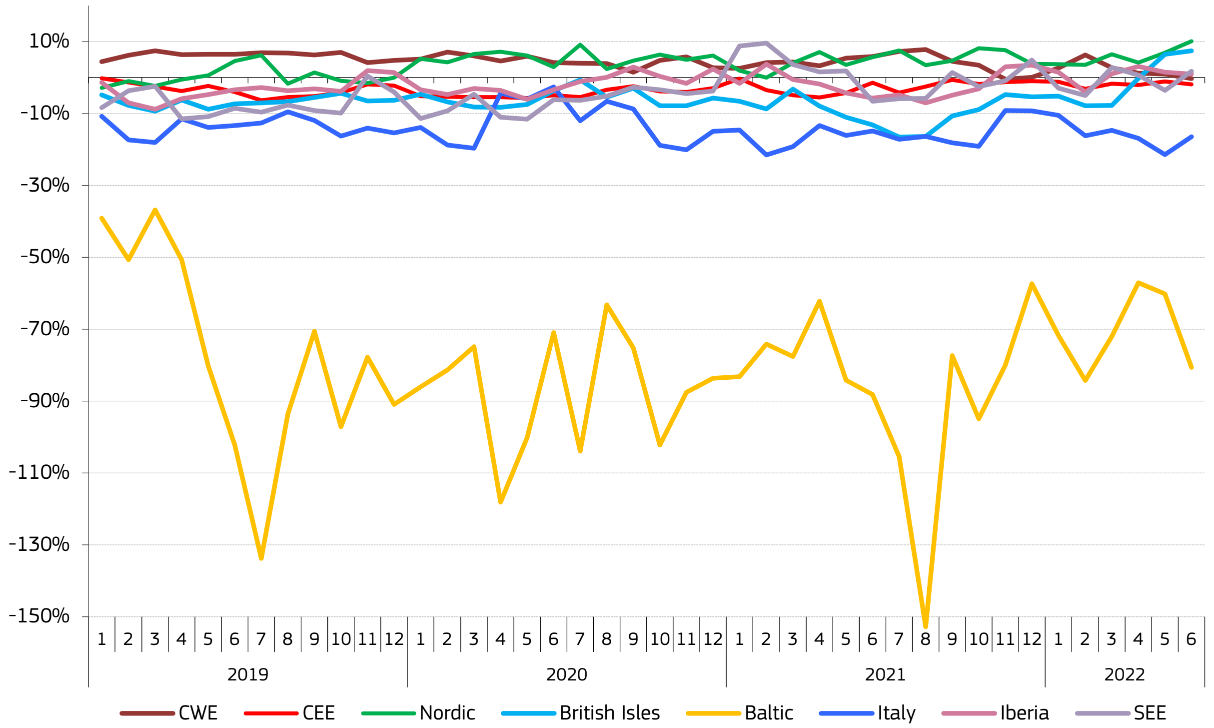
Figure 27 – European cross-border monthly physical flows by region



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 29** 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 2022 compared to the same quarter a year ago. Net imports (2.6 TWh) reached about 66% of domestic generation. Italy became the second largest importer relative to its domestic generation (18%). For the rest of the regions, net imports (or exports) did not exceed 7% of domestic generation.

Figure 28 – 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 Regional wholesale markets

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

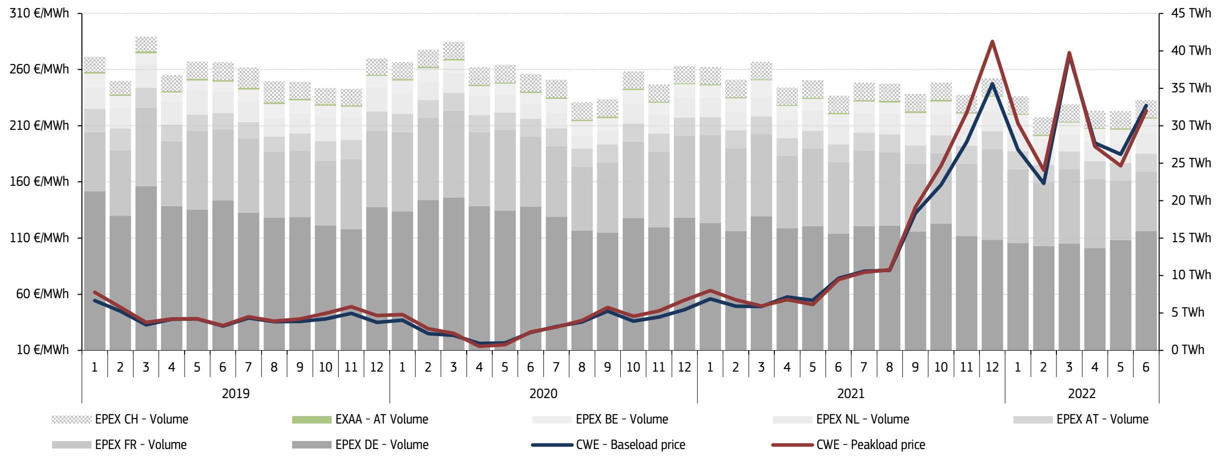
- Wholesale electricity prices in Central Western Europe (CWE) showed a fluctuating trend in the first and second quarter of 2022 around historically high values. Record high levels reached in March 2022 following the Russian invasion of Ukraine were duplicated and surpassed during the summer, amid reduced gas deliveries from Russia and an increasingly tight energy market. Compared to Q2 2021, the average baseload price in the region increased by 226% to 202 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 229% to 196 €/MWh.

- In France, nuclear generation has drastically decreased, reaching a new record low in June 2022. EDF has lowered expectations of nuclear availability for 2022, on account of unprecedented high number of outages and some delay in the return dates of multiple reactors, due to corrosion problems or scheduled maintenance. Nuclear generation decreased from 5.2 TWh in the first week of April 2022 to slightly more than 4.6 TWh in the last week of June 2022. Subdued nuclear generation continued well into Q3 2022, and it reached a new low in the last week of August (3.8 TWh). other factors, the reduced nuclear fleet availability is keeping the French forward contracts in premium over Germany (see **Figure 16**). On 6 July, the French government announced the nationalisation of Electricité de France (EDF), the main electric power generator of France. On 14 September, the French power grid operator warned of period of tight electricity supply during this winter in a provisional winter outlook. The possibility of load-shedding measures during potential extreme weather was not ruled out.

- The Eurotunnel interconnector (1 GW ElecLink) started commercial operations on 25 May, with UK power flowing into France. The link has boosted interconnection between France and the UK to 4 GW. However, the total interconnection capacity between the markets is limited to 2.8 GW due to the repairs on the 2-GW IFA-1 link.

- In Germany, the government triggered the second level of its emergency gas plan and announced in June its plan to reactivate 10 GW of coal capacity in reserve to mitigate the impact of Russian gas cuts. In addition, the country has three remaining nuclear reactors (Isar-2, Neckarwestheim-2 and Emsland) which are expected to cease operation at the end of 2022. Germany already closed three reactors at the end of 2021, as a result of a national nuclear power and coal phase-out policy. The nuclear closures added extra tightness and combined with expensive gas prices, supporting record highs of German power prices during this year. The Russian invasion of Ukraine has reignited the debate in Germany on the closing of nuclear reactors, regarding the important share of gas import from Russia in the country. The German government announced at the end of September, that it will keep two nuclear plants (Isar-2 and Neckarwestheim-2) in a reserve until April 2023, to help limit supply tightness during the coming winter season.

Figure 29 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



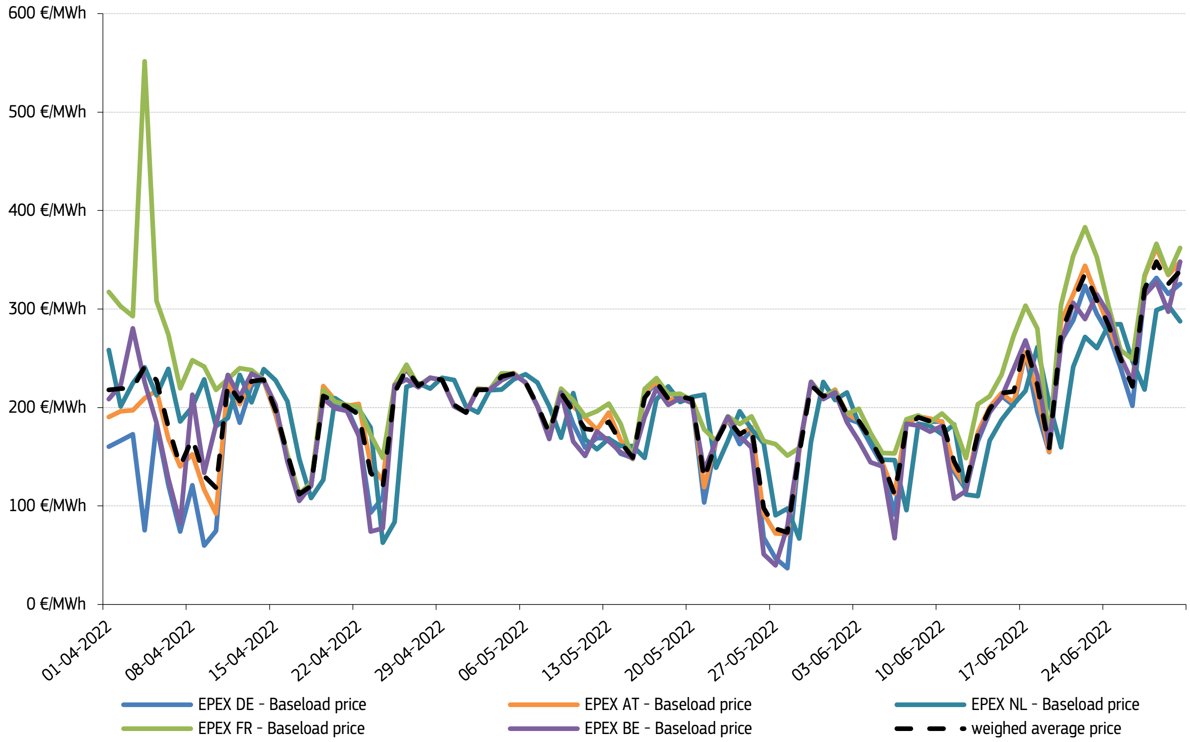
Source: Platts, EPEX. Volumes for EPEX-CH and EPEX-AT are missing.

- **Figure 31** shows the daily average day-ahead prices in the region in the reference quarter. Daily average prices in CWE remained at historically high values around 200 €/MWh in Q2 2022, after having reached record levels in Q1 2022. The final part of the quarter showed a steady increase of prices up and above 300 €/MWh, following the corresponding increase of gas prices on the main European hubs. On 4 April, French day-ahead prices registered

551 €/MWh, with hourly peaks of 2,988 €/MWh between 08:00 and 09:00, after the French grid operator called large consumers to reduce consumption as a result of a cold snap. The total load during that hour was set at 71 GW in the French bidding zone. Domestic generation was maxed at 63 GW, while imports increased to 11 GW to meet demand during that time.

- The tightness of the gas market, the lower-than-average outputs from French nuclear power plants and the consistent droughts hitting large part of Europe in the Spring and Summer 2022, sustained high power prices in the CWE region.

Figure 30 – Daily average power prices on the day-ahead market in the CWE region

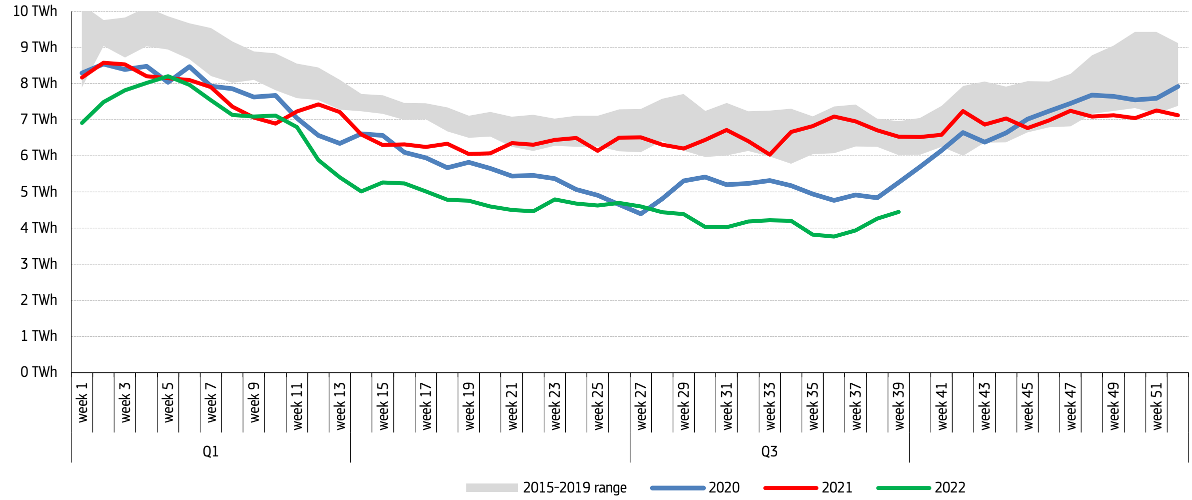


Source: Platts.

- As shown in **Figure 32**, French nuclear output was significantly down by 24% (-20 TWh) year-on-year in Q2 2022. Nuclear generation has drastically decreased, reaching a new record low in August 2022 (weekly average around 4 TWh). EDF has lowered nuclear availability for 2022, as the fleet experienced an unprecedented high number of outages combined with scheduled maintenance in 2022 (estimated output at 280. During the last days of September, France registered 29 reactors available (out of 56). EDF announced in September that it expects most of the fleet to be ready by the end of the year, and to finish the restart of the remaining reactors by 18 February 2023. Indeed, 19 reactors are scheduled to return in Q4 2022, while 6 are scheduled to return in the first months of 2023.

- In Belgium, after 40 years of operation, Doel 3 nuclear generator was permanently disconnected from the grid on 23 September, in agreement with the scheduled phase-out plan of nuclear energy. Doel 3 is the first nuclear reactor to be shut down as part of the plan. The Belgium federal government had initially planned to decommission the existing nuclear capacity (6 GW) by 2025. However, in the light of the Russian invasion of Ukraine and the consequent disruption of the European energy markets, Belgium has agreed to extend the operation of Doel 4 and Tihange 3 reactors until 2035 (2GW).

Figure 31 – Weekly nuclear electricity generation in France

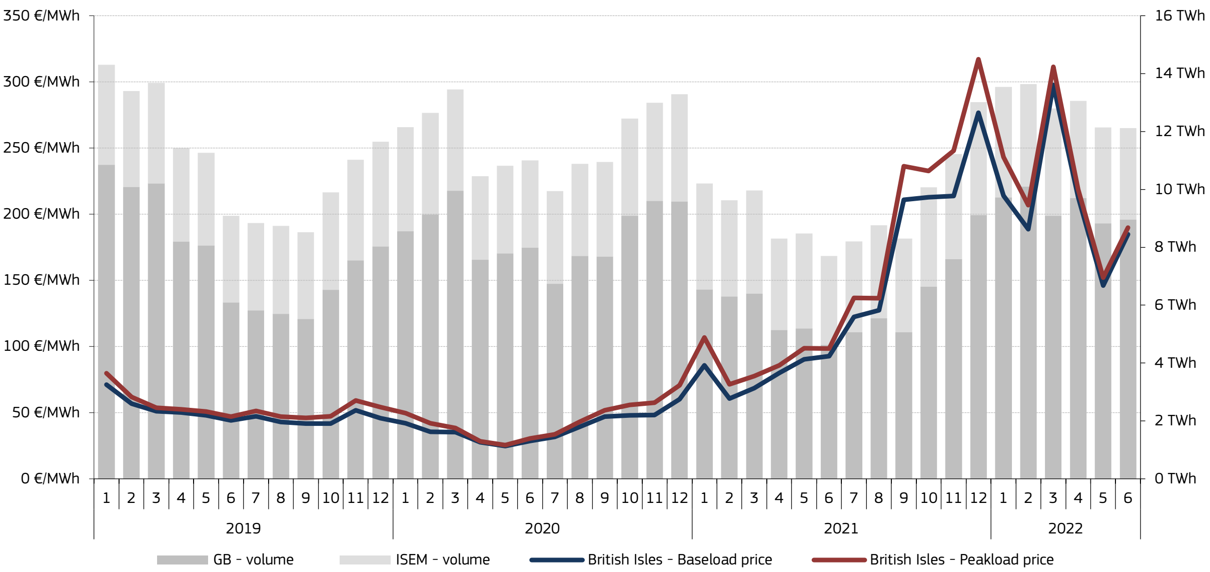


Source: ENTSO-E

3.2 British Isles (GB, Ireland)

- **Figure 33** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market of Ireland. Monthly averages for both baseload and peakload power rose reaching new all-time highs during the last month of Q1 2022, to decrease substantially in Q2 2022. The favourable position of the British Isles, less dependent than mainland Europe from Russian energy commodities and increased LNG imports supported lower prices of gas in the British Isles, compared with mainland Europe. Thus, Q2 2022 wholesale electricity prices fell further than in the continent, supporting the change of traditional direction of flows between the British Isles and the continent, where Q2 2022 saw the British Isles acting as a net exporter to mainland Europe. After having sharply increased to 298 €/MWh in March (+58% from February 2022, +333% year-on-year), prices dropped to 146 €/MWh in May 2022 (+62% year-on-year) and resurged to 185 €/MWh in June (+99% year-on-year). Compared to Q2 2021, the average baseload price on the British Isles rose by 107% to 181 €/MWh during Q2 2022 and decreased by 22% from Q1 2022.

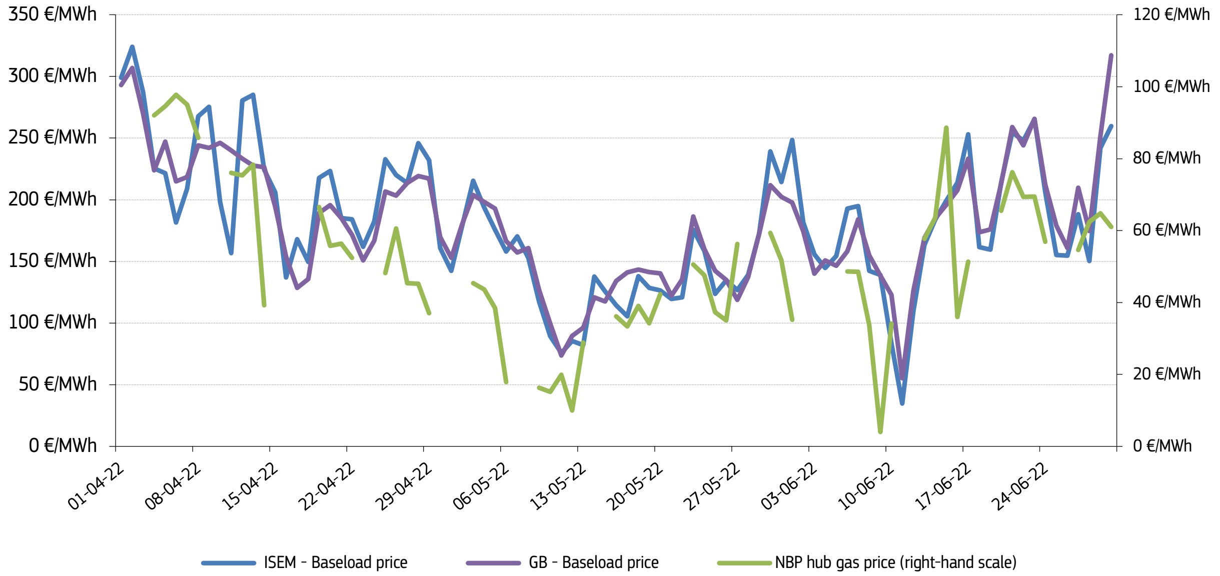
Figure 32 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 34** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices have experienced strong volatility and opposite spikes along Q2 2022. The highest values were registered at the beginning and at the end of the quarter and were driven by the NBP prices following geopolitical situation and the resulting tight gas market. The Irish market registered its highest quarterly value on 2 April (324 €/MWh).

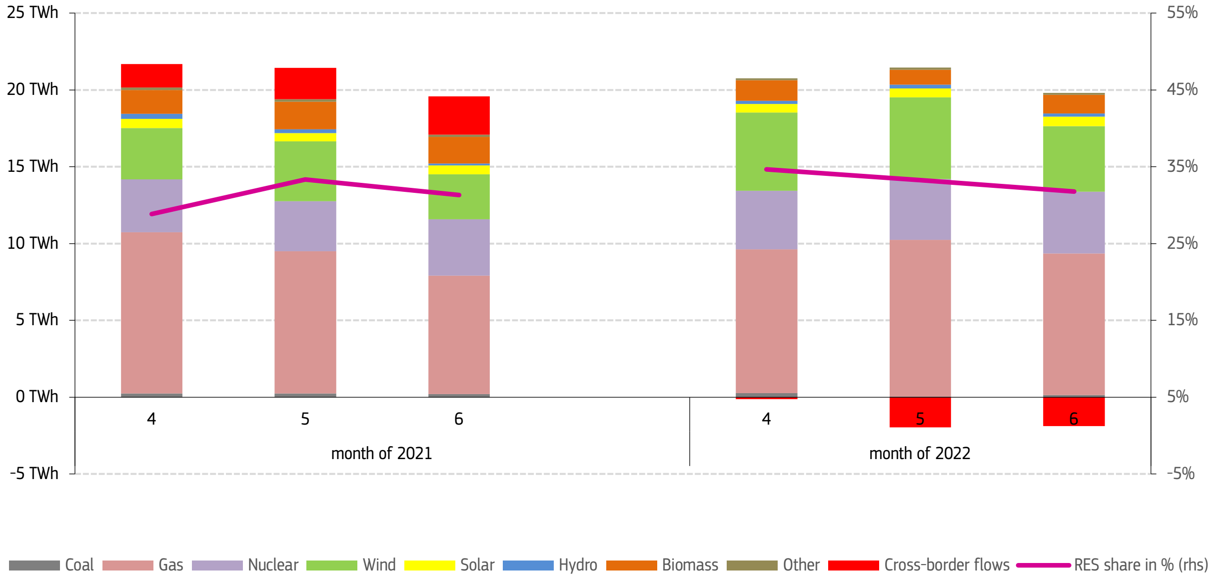
Figure 33 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 35** shows the increase of electricity net exports during Q2 2022, changing UK's traditional net importer position. UK also registered improved gas and nuclear generation between Q2 2021 and Q2 2022. The renewable share increased from 31% in Q2 2021 to 33% in Q2 2022, supported by a surge in wind output (+45%). Nuclear generation was 14% higher during Q2 2022, despite the closure of Hunterston B nuclear plant. The share of net imports from the continent compared with total generation decreased from 11% in Q1 2021 to -7% in Q2 2022 (net exports). The position of coal drop significantly (-38%), with May registering almost no coal output. Gas generation registered an increase of 5% compared to Q2 2021. Gas-fired generation remained the largest share of generation mix.
- EDF is planning to extend the life of Hartlepool and Heysham I nuclear reactors beyond the current expected end date of March 2024 (2 GW of capacity altogether). Two nuclear power plants ended generation in 2021 (Dungeness B in 2021 and Hunterston B in Q1 2022). The nuclear fleet of the UK is set to be retired by 2028 (Torness, Hinkley Point B, Heysham 1, Heysham 2 and Hartlepool), with the exception of Sizewell B, to be closed in 2035. However, the new nuclear plant Hinkley Point C is expected to come online in 2026.

Figure 34 – Evolution of the UK electricity mix between Q2 2021 and Q2 2022

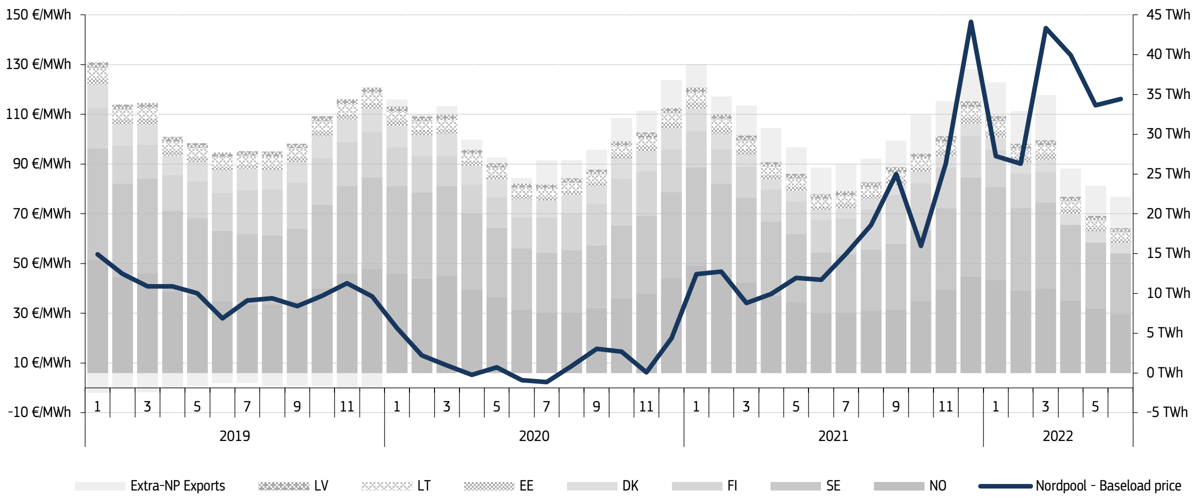


Source: BEIS. Positive values of cross-border flows indicate net imports

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

- As shown in **Figure 36,** Nord Pool prices baseload prices remained elevated in Q2 2022, but showing a decreasing trend. Prices reached a low of 114 €/MWh during May (-22% from the high in March 2022). Compared to Q2 2021, the average system baseload price surged by 189% from 42 €/MWh in the reference quarter.
- Finland is expected to improve its condition of net importer of electricity when Olkiluoto-3 nuclear power plant is commissioned in December 2022. As part of the commissioning tests, the nuclear plant recently reached full electrical power (1600 MW) for the first time at the end of September. Olkiluoto-3 will significantly improve Finland's position, especially after Russian exports of electricity were suspended to Finland on 14 May. Finland also expects to improve security of supply with the 440 kV interconnector Aurora Line between Sweden and Finland, which is expected to be completed in 2025. The new interconnection capacity is expected to enable the connection of 800 MW between the Finnish grid and the cheap north Sweden bidding zone.

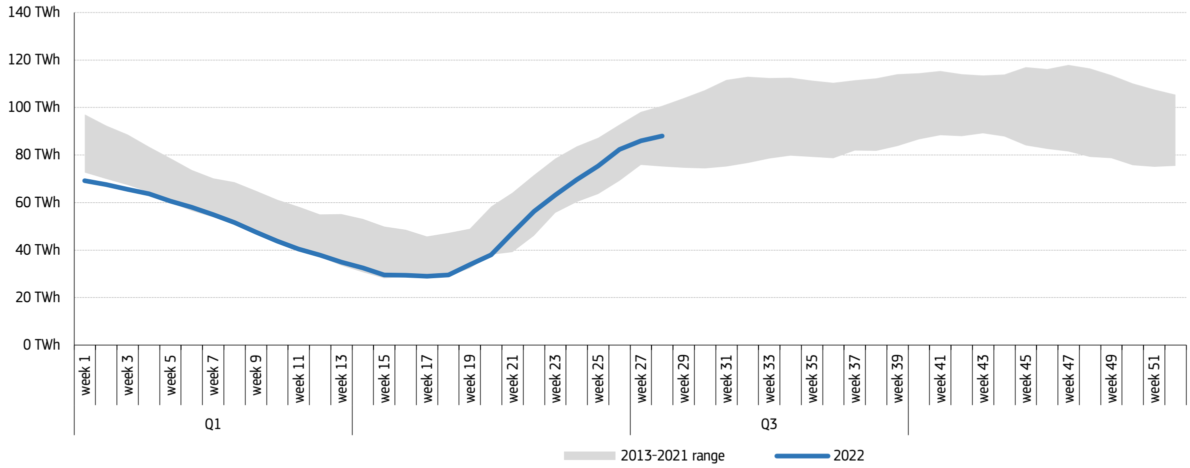
Figure 35 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 37** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2022 compared to previous nine years. In Q2 2022, hydro stocks declined in line with seasonal demand and were exacerbated by below average temperatures during April. Dry and cold weather condition in the area triggered this reduced reservoir level in the during Q1 2022 and the first part of Q2 2022. Hydroelectric stocks reached a low of 29 TWh during the third week of April, dropping below historical levels. Since then, stocks have increased to 82 TWh, during the last week of June.

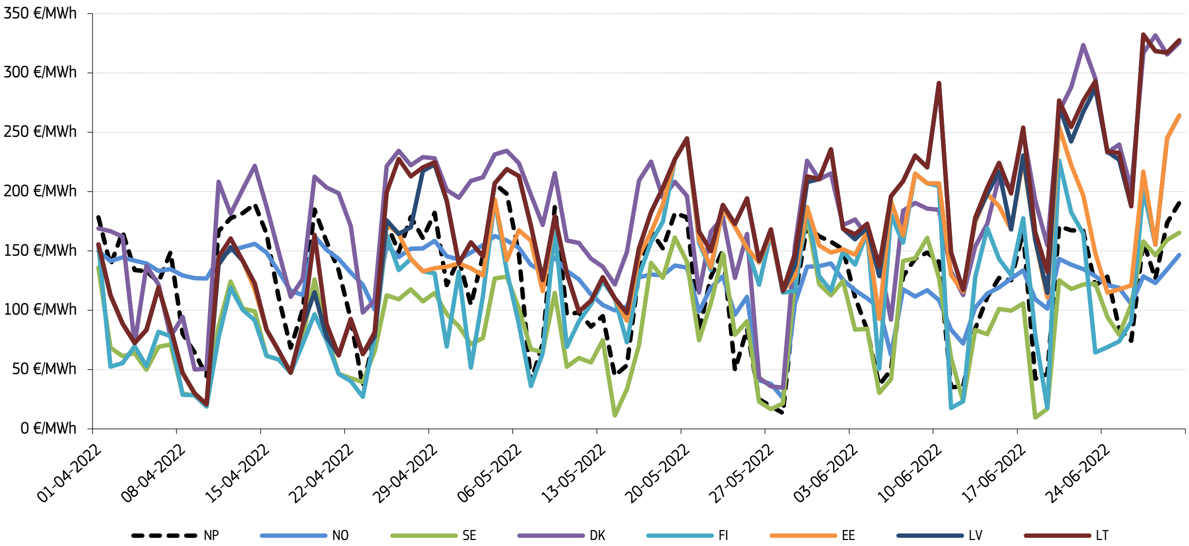
Figure 36 – Nordic hydro reservoir levels in 2022, compared to the range of 2013-2021



Source: Nord Pool spot market

- **Figure 38** shows that average daily prices across Northern Europe continued to display a high degree of divergence and volatility throughout Q2 2022. The highest daily regional price registered in the reference quarter reached 206 €/MWh on 4 May, whereas the lowest daily regional price registered dropped to 13 €/MWh on 28 May,. The highest spike was recorded in Lithuania on 27 June (332 €/MWh).

Figure 37 – Daily average regional prices and the system price on the day-ahead market in the Nordic region



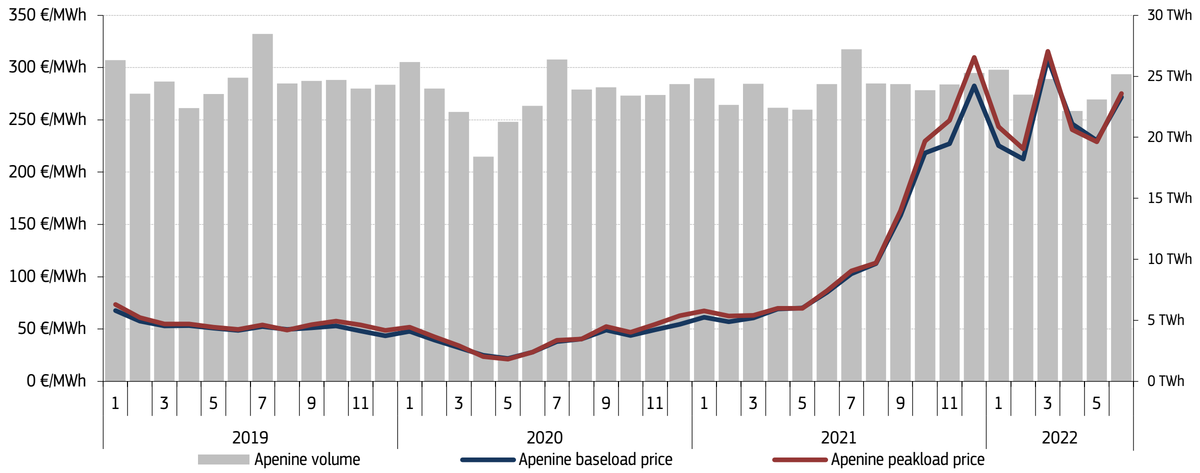
Source: Nord Pool spot market

3.4 Apennine Peninsula (Italy, Malta)

- Following a peak in March 2022 (308 €/MWh), Italian monthly average baseload electricity prices (**Figure 39**), experienced a drop in April (246 €/MWh) and May 2022 (230 €/MWh). Yet, the Italian market prices climbed back to 271 €/MWh in June, following the developments in the gas market (Italy has the highest share of gas-fired generation in the EU). At 249 €/MWh, the Italian market recorded the largest average baseload price in Europe during Q2 2022 (together with Malta). The average baseload price rose by 234% compared to Q2 2021, remaining practically unchanged from Q1 2021 levels. Trading volumes increased by 3% compared to the previous second quarter.

- Italy, like other Member States, has been taking measures to alleviate the effect of high energy prices to end-consumers. The Italian government has been putting in place several emergency packages to mitigate the impacts of the energy prices surge in May, June and September.
- The 1.2 GW Savoy-Piedmont link between Italy and France start of operations was delayed to the end of 2022. The link will boost the interconnection between France and Italy to 4.3 GW and 2.2 GW in the opposite direction. Italy has eleven projects of interconnection planned by 2030, including increased capacities with Austria, Slovenia, Greece, Switzerland and Montenegro, and a new cable to Tunisia. A new link to Austria (300 MW) via Nauders is scheduled to start operating in 2023, while a new expansion at the Brenner Pass (100 MW) is set to go online during the same year.

Figure 38 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 40** 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 200 and 350 €/MWh during April and May. In June, prices increased in the range of 250-380 €/MWh. Prices reach a peak value at 386 €/MW on 28 June, due to sky-rocketing gas prices following the worsening of the geopolitical picture around the limitation of flows via Nord Stream pipeline.
- Italy is one of the largest producers of electricity from gas in the EU, despite a 5% fall in gas-fired generation in Q2 2022 (gas represented 46% of the total generation in Italy during Q2 2022). Rising commodity prices, especially gas, played an important role in the surge of prices. In 2021, Italy imported 40% of its gas from Russia, the second highest ranking country in the EU. The impact of the Russian invasion of Ukraine and the uncertain political situation connected to the war, have heavily impacted gas prices in Italy. In addition, the major Russian company cut-off of deliveries to Italy increased pressure on an already tight energy market as a result of a drought and heat wave.
- 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. Traditionally, the Maltese zone forms the upper boundary of the band of regional prices. However, as visible in **Figure 40**, the trend has shown an intermittent development in Q2 2022, as prices in the Maltese area not always stayed in the upper bound of regional prices. However, Maltese prices were higher than the Italian market during the second quarter of 2022.

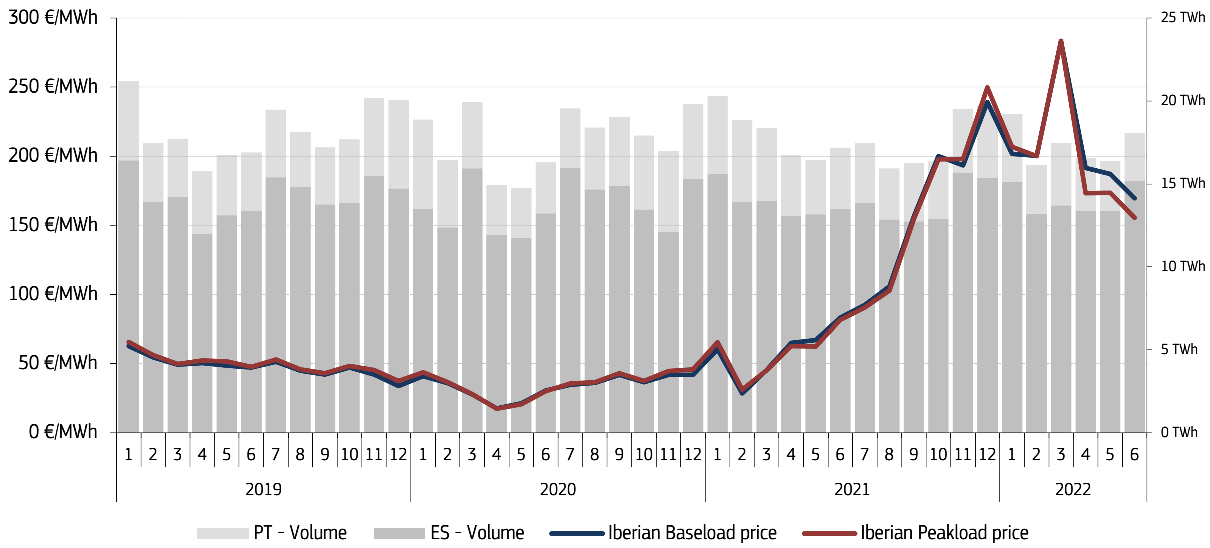
Figure 39 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

Source: GME (IPEX)

3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 41** reports on monthly average baseload and peakload contracts in Spain and Portugal. After the March peak, prices fell during the second quarter of 2022. Following March prices reaching a peak of 283 €/MWh, after the Russian invasion of Ukraine, prices fell to 191 €/MWh and to 187 €/MWh, in April and May, respectively. Moreover, baseload average monthly prices fell to 170 €/MWh in June, supported by the start of the 'Iberian exception' measure. Compared to Q2 2021, the average baseload price rose by 155% to 183 €/MWh in Q2 2022. Peak prices increased by 143% to 167 €/MWh. Trading activity registered a slight increase (+1%) compared with the previous Q2.

Figure 40 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula

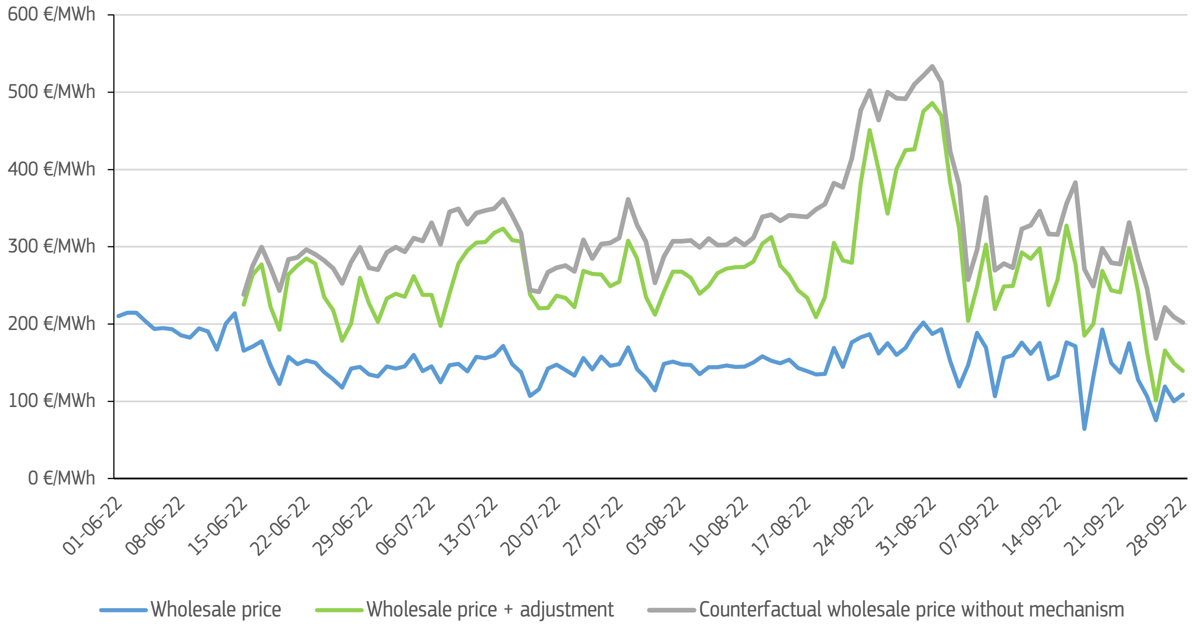


Source: Platts, OMEL, DGEG

- Nearly 10 million customers (40% of consumers in Spain) are on tariffs directly linked with the wholesale electricity market. In light of the surges in wholesale prices, the Government has been issuing new measures taken to tackle the social and economic effects of rising energy prices. To that end, an exceptional cap on the price of gas used for power generation came into force on 14 June in the day-ahead markets of the Iberian Peninsula. The measure, negotiated between Spain, Portugal, and the European Commission, was approved on 8 June 2022 by the Commission. Given the low interconnectivity of the Peninsula with the rest of Europe, the 'Iberian exception' measure allows for a temporary cap on the gas price for power generation to mitigate the impact of soaring prices on end-consumers. The adjustment mechanism is financed by the surplus in congestion rents obtained by the Spanish grid operator resulting from electricity trade with France and a charge imposed by the Iberian countries on buyers benefitting from the measure. The measure has resulted in lower wholesale prices in the Iberian market while at the same time, it has partially contributed to reverse power flows between Spain and France and increase gas-fired generation However, these developments need to be seen in the context of the trend decreasing net imports in Spain and the subdued hydropower generation, due to a drought in the country.

- **Figure 42** reports on the developments in wholesale prices since the start of the mechanism (15 June 2022) up to 30 September. Overall, since the start of the exception, the wholesale electricity price has averaged 147 €/MWh, registering a 54% decrease in comparison with the average counterfactual wholesale price without the mechanism (EU wholesale prices increased by 25% during this period). Also, final consumers with tariffs linked with the wholesale price have paid an average compensation of 119 €/MWh, thus consumers have benefitted by 17% from the measure.

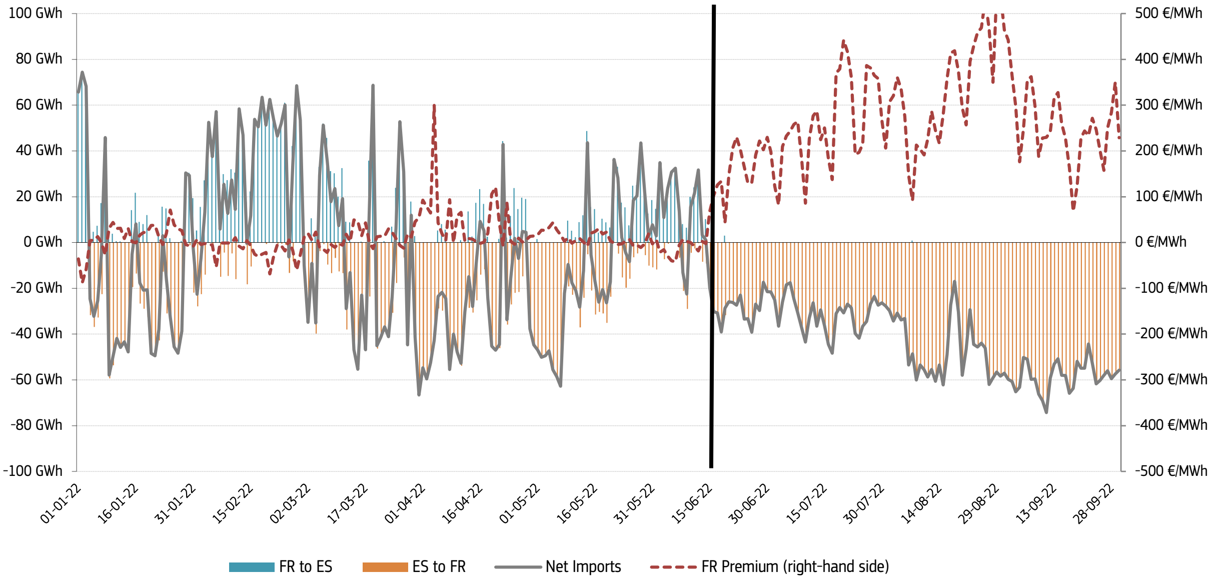
Figure 41 – Iberian market day-ahead electricity prices



Source: OMIE, DGEG

- **Figure 43** shows daily electricity flows between France and Spain and price differentials between the two bidding zones from January to September 2022. Since the introduction of the measure and along with the reduction of the traditional French premium, exports from France to Spain have practically disappeared, while flows from Spain to France have risen. This development needs to be seen in the context of subdued nuclear availability of the French nuclear fleet, which has made electricity prices higher in France to change its traditional role as exporter and turn into a net importer, not only from Spain, but also from other Member States and the United Kingdom in 2022.

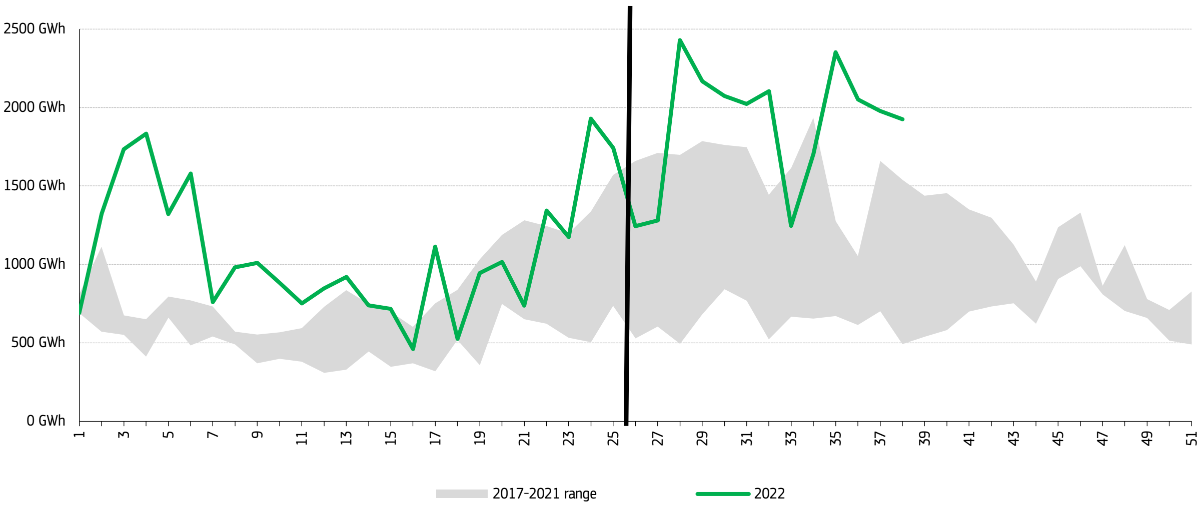
Figure 42 – Daily electricity import balance for Spain and France and price differentials between them in 2022 (January – September)



Source: ENTSO-E

- **Figure 44** reports the evolution of gas-fired generation in Spain during 2022 (January – September) compared to a range of the previous five years (2017-2021). From 15 June to 30 September, gas-fired generation rose by 54% compared with the average value during the same period between 2017-2021. However, gas-fired generation levels were already 50% higher during the period before the introduction of the measure (January to mid-June), in comparison with the same period in 2017-2021 (Q1 2022 recorded an increase of 69% in gas-fired generation year-on-year). The levels of gas consumption in the period under study were also influenced by weather conditions, with higher-than-usual electricity demand for cooling compounded with severe droughts that led to lower electricity generation from hydropower. All this, led to a resort to gas for electricity production above normal levels.

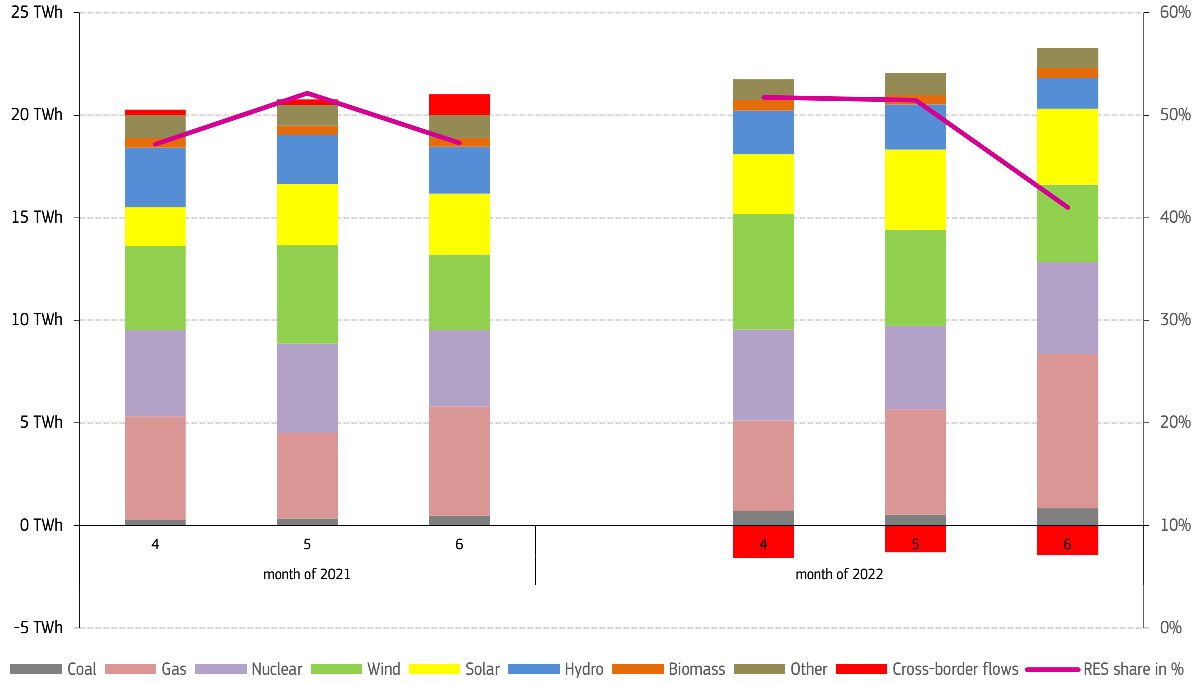
Figure 43 – Weekly gas-fired electricity generation in Spain



Source: REDEE

- **Figure 45** displays the evolution of the monthly electricity generation mix in Spain during the second quarter of 2022, as well as during the same period of the previous year. Net generation increased by 11% year-on-year. The share of renewable electricity sources fell slightly to 48% in Q2 2022 (registering a monthly average of 52% in April, 51% in May, down to 41% in June), from an average of 49% in Q2 2021. Wind generation increased by 13%, whereas solar output rose by 34%. Gas generation rose by 17% (+2.5 TWh), covering a share of 25% of the total generation. The reduced remaining coal capacity registered an increase in production by 90% (+1 TWh) year-on-year in Q1 2022. Nuclear generation increased its output by 6% and covered a share of 19% of the total generation. In Spain, net exports accounted for 6% of the total generation during the second quarter of 2022.

Figure 44 – Monthly evolution of the electricity generation mix in Spain in Q2 of 2021 and 2022

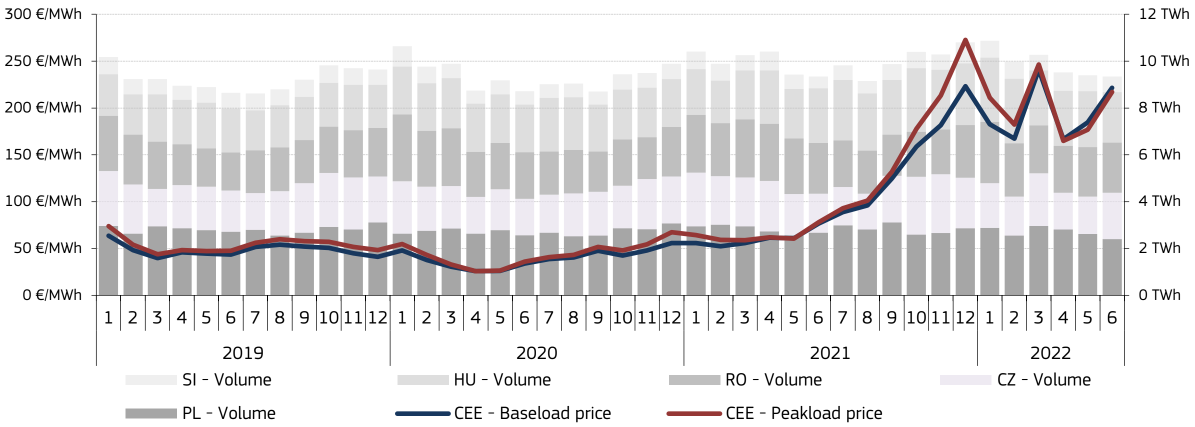


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- **Figure 46** shows that average monthly prices for baseload power in Central Eastern Europe remained at historically high levels. After the peak in March (241 €/MWh), baseload prices fell in April to 167 €/MWh and rebounded to 221 €/MWh in June, supported by the uncertainty connected with the Russian gas pipeline supplies. When compared to Q2 2021, the average baseload price in the reference quarter rose by 188% to 191 €/MWh, still 3% lower than the average in Q1 2022. Traded volumes in the reference quarter fell by 3% compared to the previous Q2.

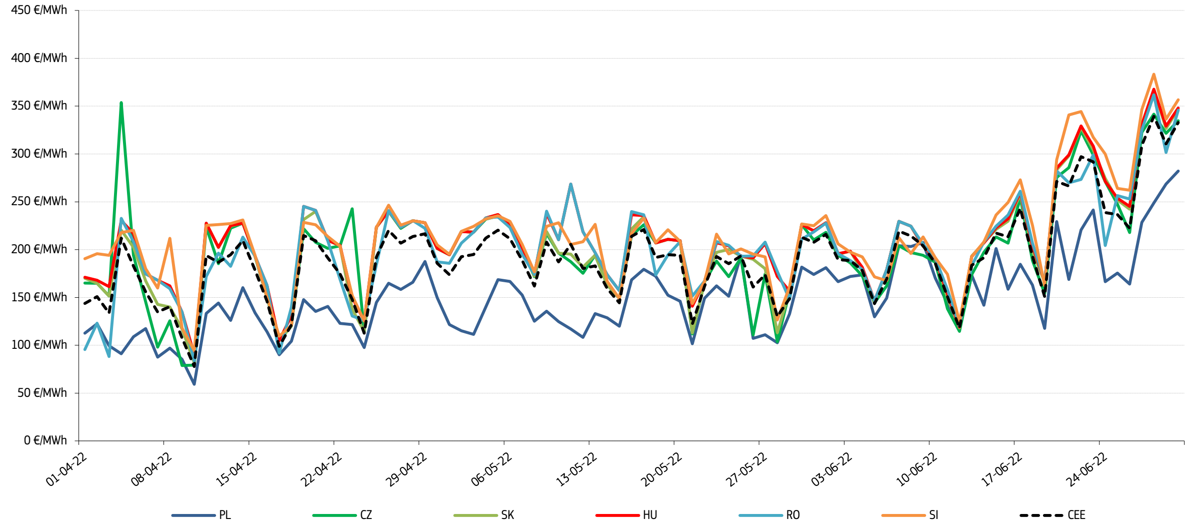
Figure 45 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 47** shows that daily average baseload prices in the markets (CZ, SK, HU, RO, PL) maintained high levels of price volatility during Q2 2022. CEE prices moved between 100 and 250 €/MWh in April and May, rising in mid-June to values around 250 and 350 €/MWh. The Polish market decreased its discount towards CEE prices from an average of -64 €/MWh in Q1 2022 to one of -42 €/MWh in Q2 2022. The large coal-fired fleet in Poland has also been taking the impact of high commodity prices (coal and also carbon). High electricity prices have also affected Member States with reduced exposure to gas, such as Poland (although to a lesser extent than markets relying on gas). This is an interesting signal towards renewables, as high penetration levels of solar and wind would reduce exposure of electricity prices to scarce energy commodities (gas and carbon).

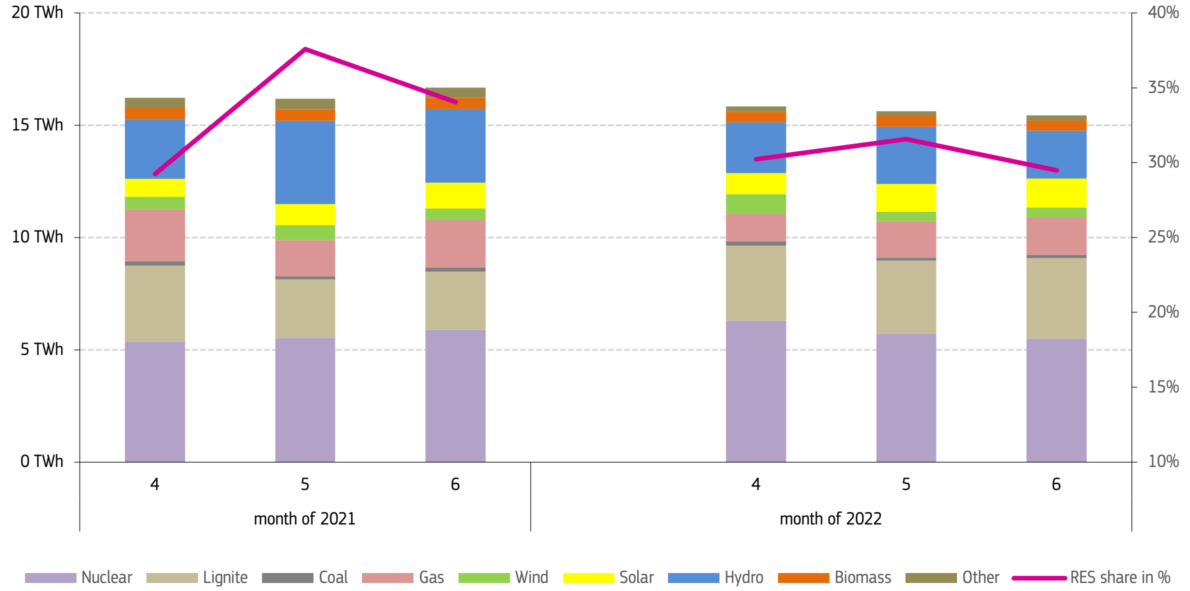
Figure 46 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 48** compares the combined electricity generation mix of the CEE region (excluding Poland) in Q2 2022 and Q2 2021. Hydro-power generation fell significantly (-28%) in Q2 2022 (especially in Slovenia registering -42% output). A rise in solar (+20%) output and small increase in wind (+2%) generation were not enough to compensate hydro losses during the reference quarter. This caused the renewable energy share to slightly drop by 4p.p. compared to Q2 2021 (from 34% to 30%). Solar generation registered a surge in Hungary and Czechia. Nuclear remained the dominant generation technology, increasing its output by 4% in Q2 2022, with a considerable presence in all five markets.

Figure 47 – Evolution of the electricity mix in the CEE region (excluding Poland) between Q2 2021 and Q2 2022



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 decreased slightly to 68% in Q2 2022 compared to 70% in Q1

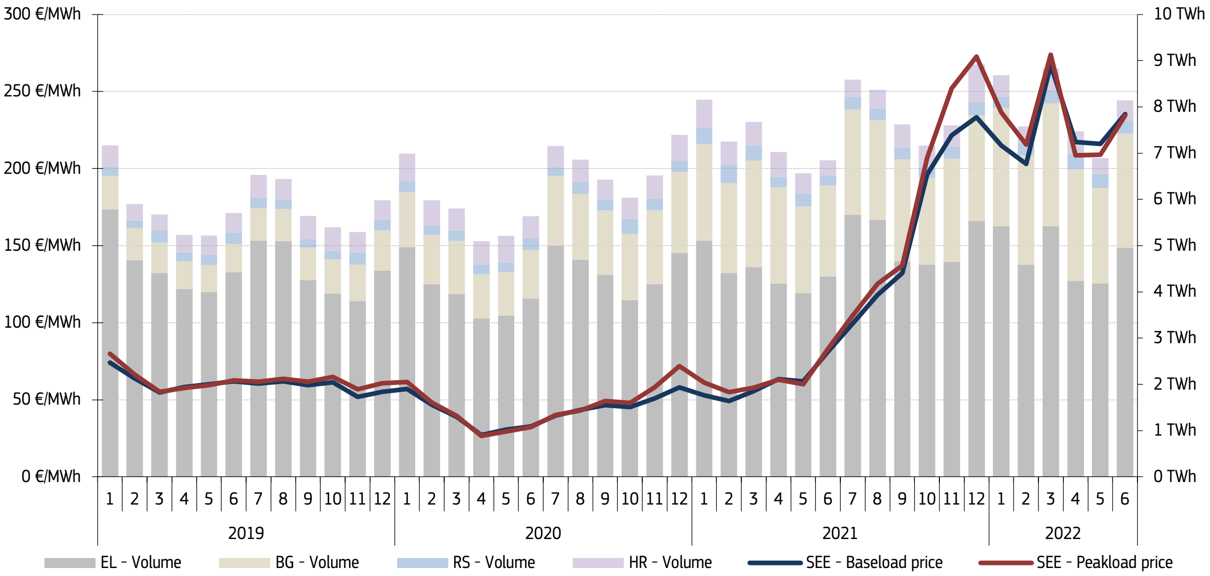
2021. Renewables increased their share from 19% in Q2 2021 to 24% in Q2 2022, thanks to booming solar generation (+102%) and the increase in wind (+27%), biomass (+3%), despite a drop in hydro (-6%) generation. Gas decreased its share in the mix from 10% in Q2 2021 to 7% in Q2 2022, underlining the limited short-term potential for coal-to-gas switching (or vice versa) and recent economic disadvantage of gas towards coal. Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations.

- The share of coal (hard coal and lignite) in Poland's mix, at 68% in Q2 2022, should decrease to 56% by 2030 thanks 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.

3.7 South-Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 49** shows that trade-weighted monthly average baseload prices in the SEE region fell in April, remained stable in May and rose again in June. After the peak baseload average prices of March (268 €/MWh), price fell in April and May to 217 €/MWh and 216 €/MWh, respectively. Strong gas prices in the context of uncertainties of Russian gas supplies to Europe influenced electricity prices up in June (235 €/MWh). Marginal costs of gas generation in countries like Greece, with high levels of generation from this energy commodity supported high energy prices, especially in June. The average quarterly baseload price rose by 224% year-on-year to 223 €/MWh in Q2 2022, 2% below Q1 2022. The average quarterly peakload price rose 216% above Q1 2021 levels to 242 €/MWh.

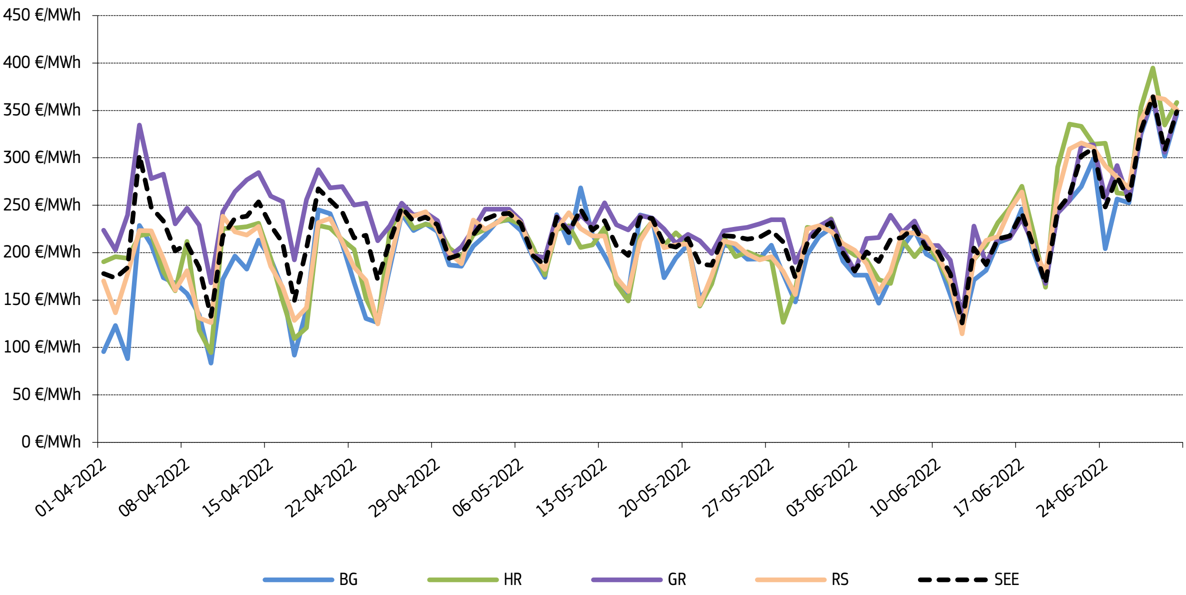
Figure 48 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- As shown in **Figure 50**, daily baseload price movements in individual markets were relatively aligned during Q2 2022, with the exception of elevated Greek day-ahead prices in early April and Croatian prices in late June. Prices remained volatile during April (between 100 and 250 €/MWh) and more stable during May (between 180 and 250 €/MWh). Prices started to rise again from mid-June onwards. Prices moved between 200 and 350 €/MWh in June. In line with the rest of Europe, wholesale electricity prices reached a high on 28 June at 365 €/MWh, on the back of the effects of high gas prices due to cuts of Russian gas supply.

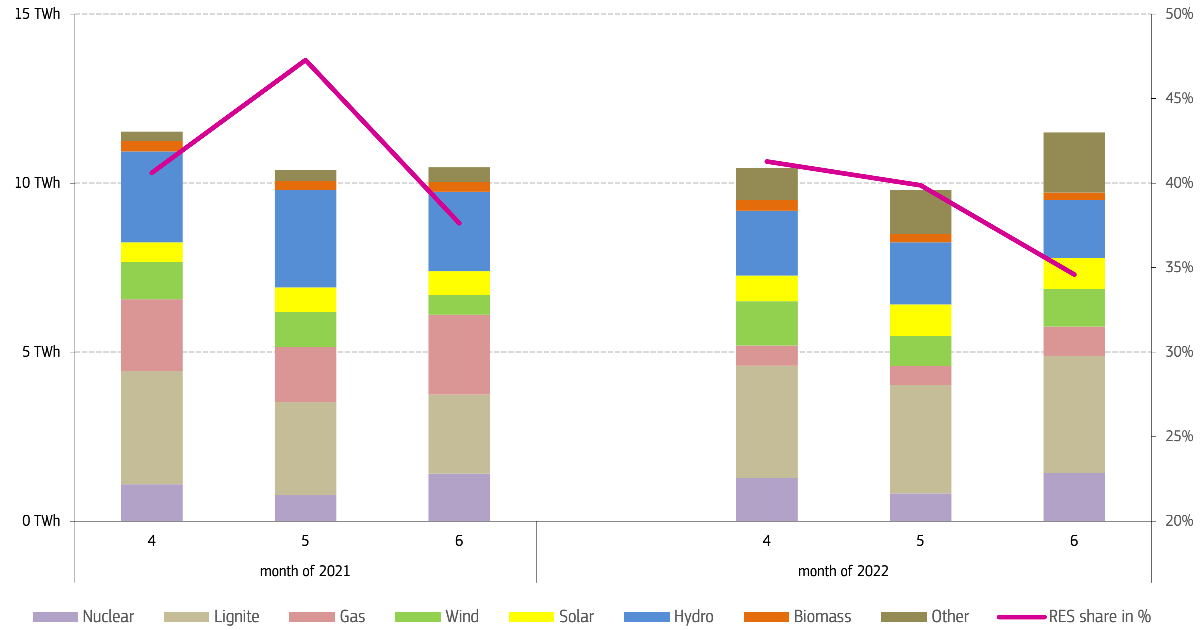
Figure 49 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 51** compares the combined electricity generation mix of the SEE region between Q2 2021 and Q2 2022. In Q2 2022, coal and lignite generation increased slightly its output (+1 TWh) year-on-year. Gas output fell by 4 TWh, while nuclear generation remained practically unchanged. Hydro output experienced a setback with 2 TWh less year-on-year. The share of lignite in the regional mix increased from 26% in Q2 2021 to 32% in Q2 2022.. Renewable penetration fell from 42% in Q2 2021, to 39% in Q2 2022 due to subdued hydro generation in the region (-31% on yearly basis). As a temporary measure to reduce gas dependency, Greece is planning to increase lignite mining in the next two years. Greece continues with its plan to phase out lignite by 2025 with the conversion of Ptolemaida 5 to natural gas. However, as European countries are putting measures in place to manage potential gas supply disruptions from Russia, Greece is testing the use of gas-fired generators with diesel. In total, 1.8 GW of gas-fired capacity could be switched to diesel.

Figure 50 – Evolution of the electricity mix in the SEE region between Q2 2021 and Q2 2022



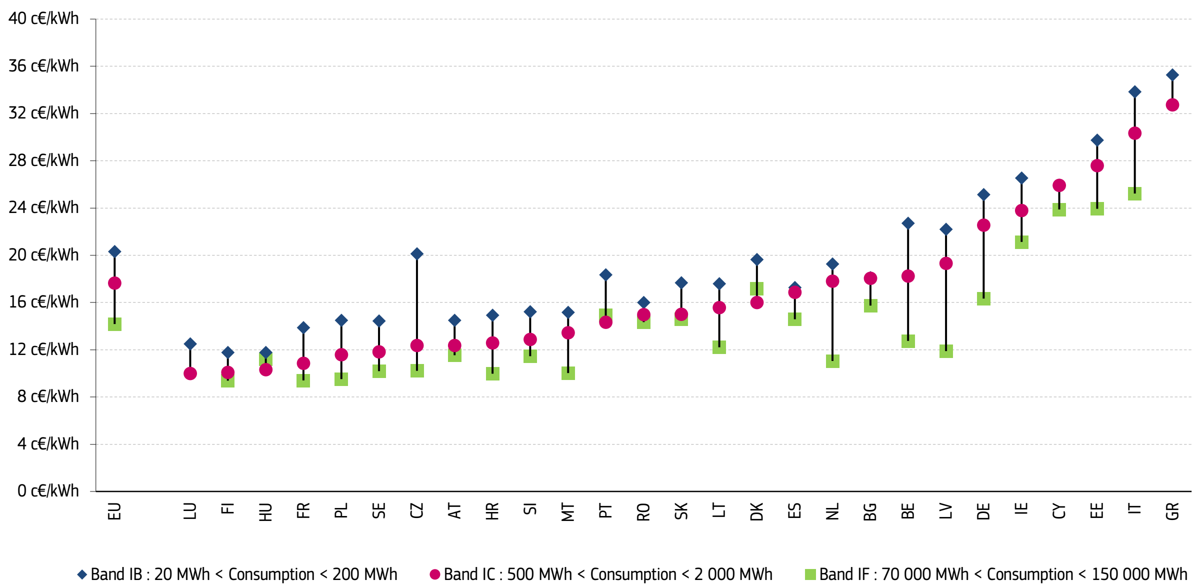
Source: ENTSO-E

4 Retail markets

4.1 Retail electricity markets in the EU

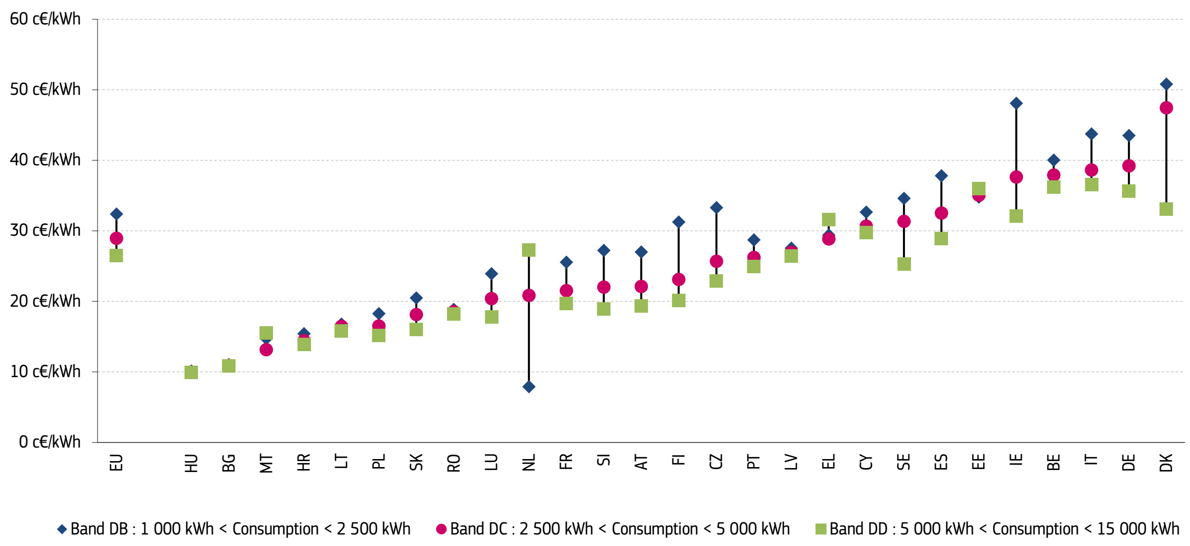
- High wholesale electricity prices have resulted in rising consumer bills for households, impacting the industry sector as well. Increasing wholesale prices are putting upward pressure on retail prices, while government interventions in some Member States are helping to alleviate the bill for consumers. The increases in retail prices could continue ahead the next heating season, as there is still room for wholesale prices to be passthrough into consumer contracts.
- **Figures 52 and 53** display the ***estimated*** retail prices in June 2022 in the 27 EU Member States for industrial customers and households. The monthly and quarterly retail prices are estimated based on the semi-annual Eurostat prices (with the latest figures available corresponding to the second half of 2021) and the variation of the Harmonized Consumer Price Indices (HICP) of electricity for both household prices and industrial consumers as a multiplier. It must be noted that by the time the next half-yearly price data will be available from Eurostat, monthly and quarterly figures might show different trends. 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 is (per MWh consumed). Hungarian, Portuguese and Danish industrial prices are an exception, while Greece and the Netherlands prices are an exception for the household consumers.
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Greece (35.3 c€/kWh) and Italy (33.9 c€/kWh), followed by the Estonia and Ireland (29.7 and 26.5 c€/kWh respectively). The lowest prices in the same category were assessed to be in Finland (11.7 c€/kWh) and Hungary (11.8 c€/kWh). The ratio of the largest to smallest reported price was almost at 3:1. Compared to June 2021, the average assessed EU retail price for the IC band rose by 32% to 17.7 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 Italy (25.2 c€/kWh), followed by Estonia and Cyprus (both at 23.9 c€/kWh) and Ireland (21.1 c€/kWh). Finland and France (9.4 c€/kWh) were assumed to have the lowest prices, with Poland and Croatia (9.5 and 10.0 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was coming close to 3:1 for this consumer type. Compared to June 2021, the average assessed EU retail electricity price for the IF band rose by 60% to 14.2 c€/kWh.
- In the household segment, Italy (36.6 c€/kWh) was assessed to have the highest electricity price for large consumers (band DD), followed by Belgium (36.2 c€/kWh), and Estonia (36.0 c€/kWh) in the third place. The lowest prices for big households were calculated for Hungary (9.9 c€/kWh), Bulgaria (10.9 c€/kWh) and Croatia (13.9 c€/kWh). Compared to June 2021, the average assessed EU retail electricity price for the DD band rose by 31% to 26.5 c€/kWh. In the case of small households, Denmark saw the highest prices (50.8 c€/kWh), followed by Ireland (48.1 c€/kWh) and Italy (43.8 c€/kWh), while the Netherlands (7.9 c€/kWh), Hungary (10.2 c€/kWh) and Bulgaria (11.0 c€/kWh) were on the other side of the price spectrum. Compared to June 2021, the average assessed EU retail electricity price for the DB band rose by 28% to 32.4 c€/kWh.

Figure 51 – Industrial electricity prices, June 2022 – without VAT and recoverable taxes



Source: Eurostat, DG ENER. Data for the IF band for LU and EL are either confidential or unavailable.

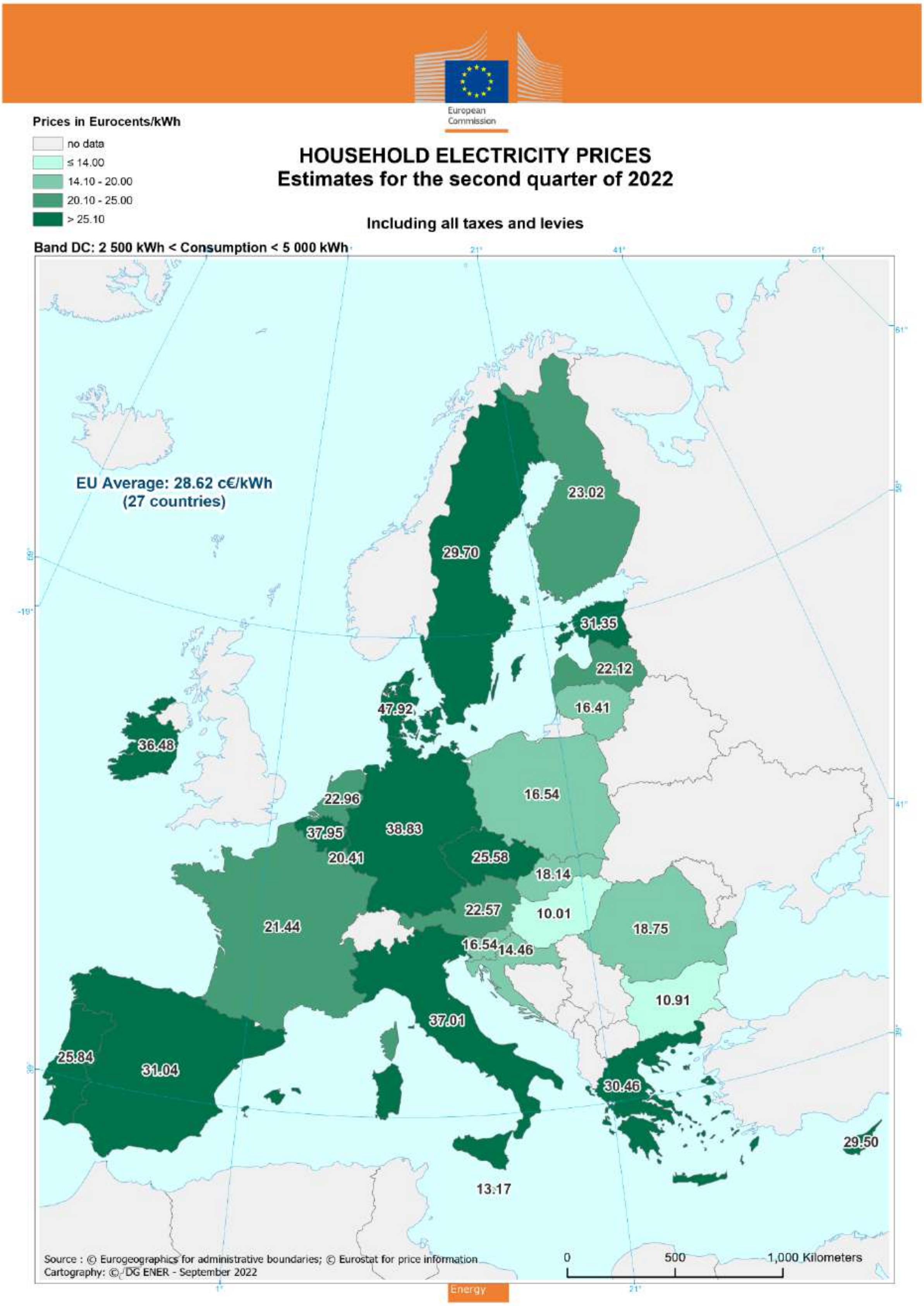
Figure 52 – Household electricity prices, June 2022 – all taxes included



Source: Eurostat, DG ENER

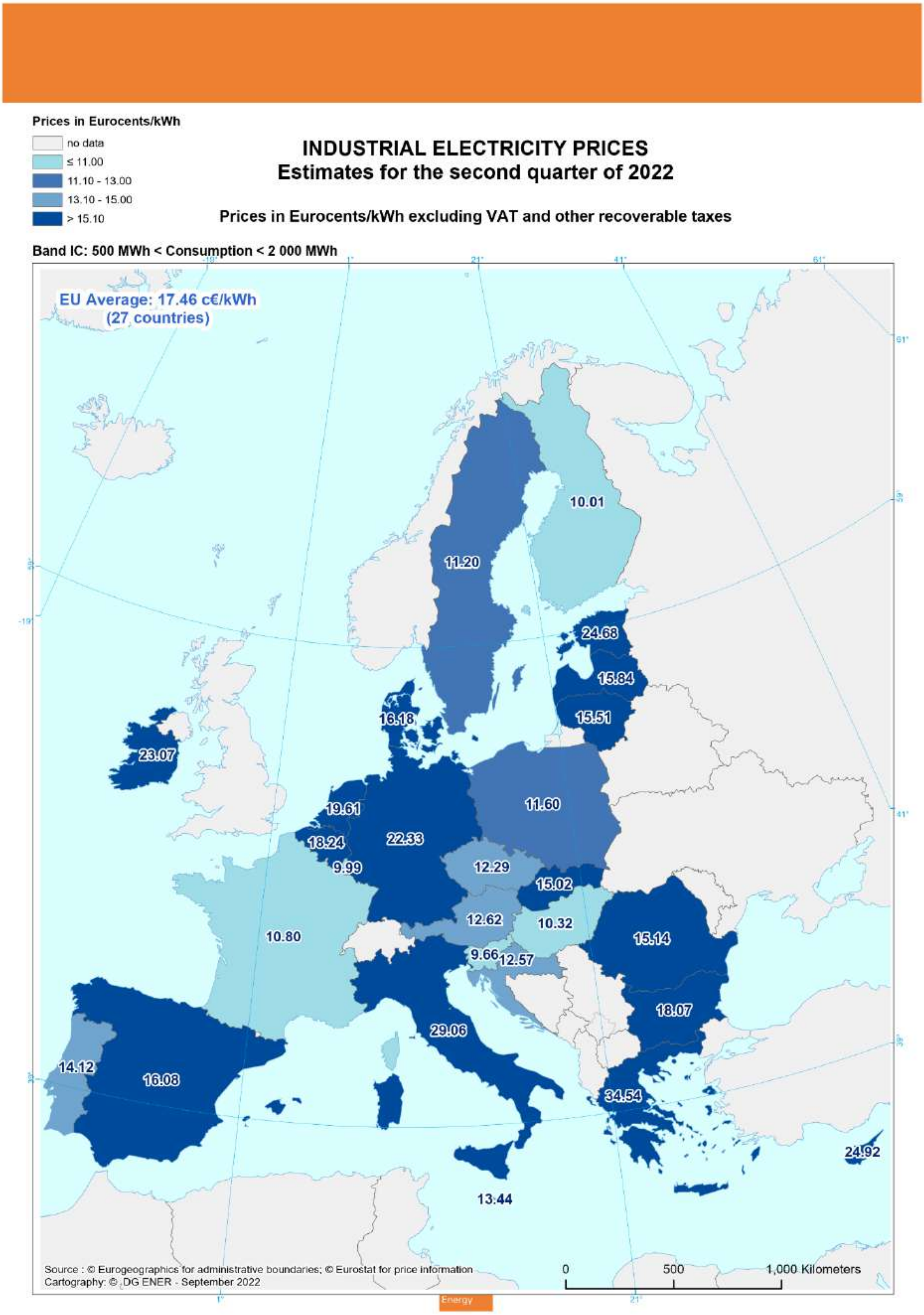
- **Figures 54 and 55** display the ***estimated*** electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the second quarter of 2022. In the case of household prices, Denmark topped the list (47.9 c€/kWh), followed by Germany (38.8 c€/kWh) and Belgium (37.9 c€/kWh). As was the case in previous quarters, Hungary (10.0 c€/kWh) and Bulgaria (10.9 c€/kWh) retained their position as Member States with the cheapest household electricity prices. The EU average increased by 29% to 28.6 c€/kWh in the reference quarter compared to Q2 2021. The largest year-on-year increases in the household category were assessed in Estonia (+135%), Greece (+81%) and the Netherlands (+75%). Year-on-year falls were estimated for Slovenia (-1%), while prices remained practically unchanged in Hungary. See **Figure 56** for more details on household prices in EU capitals.
- In the case of mid-sized industrial consumers, Slovenia was assessed to have the most competitive price in Q2 2022 (9.7 c€/kWh), followed by Luxembourg and Finland (10.0 c€/kWh). Meanwhile, Greece (34.5 c€/kWh), Italy (29.1 c€/kWh) and Cyprus (24.9 c€/kWh) stood at the other end of the spectrum. At 17.5 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 32% compared to Q2 2021. Greece (+194%), Estonia (+156%) and Denmark (+101%) marked the largest year-on-year increases in the industrial consumer category. Prices in Malta remained practically unchanged.

Figure 53 – Estimated household Electricity Prices, second quarter of 2022



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

Figure 54 – Estimated industrial Electricity Prices, second quarter of 2022



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

- **Figure 56** 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). Retail electricity prices for household costumers in EU capital cities were up by 54% in August 2022, compared to the same month in 2021. The highest prices were observed in London, Copenhagen, Amsterdam and Rome (65.4, 54.7, 50.9 and 50.8 c€/kWh, respectively). Following the increase in wholesale energy prices, in the vast majority of EU capitals, the energy component share increased. It now surpasses 50% of the total retail price in 20 EU capitals, up from 8 in Q2 2021. The energy component share is highest in Nicosia and Rome (82%). Amsterdam represents a special case as explained below. The lowest prices among EU capitals were recorded in Budapest (9.2 c€/kWh), Valletta (12.3 c€/kWh) and Zagreb (14.8 c€/kWh). EU-wide, retail prices have started a steep climb since September 2021. Moreover, pushed by high wholesale prices, retail prices kept increasing throughout the year, intensifying the pressure on inflation throughout 2022,

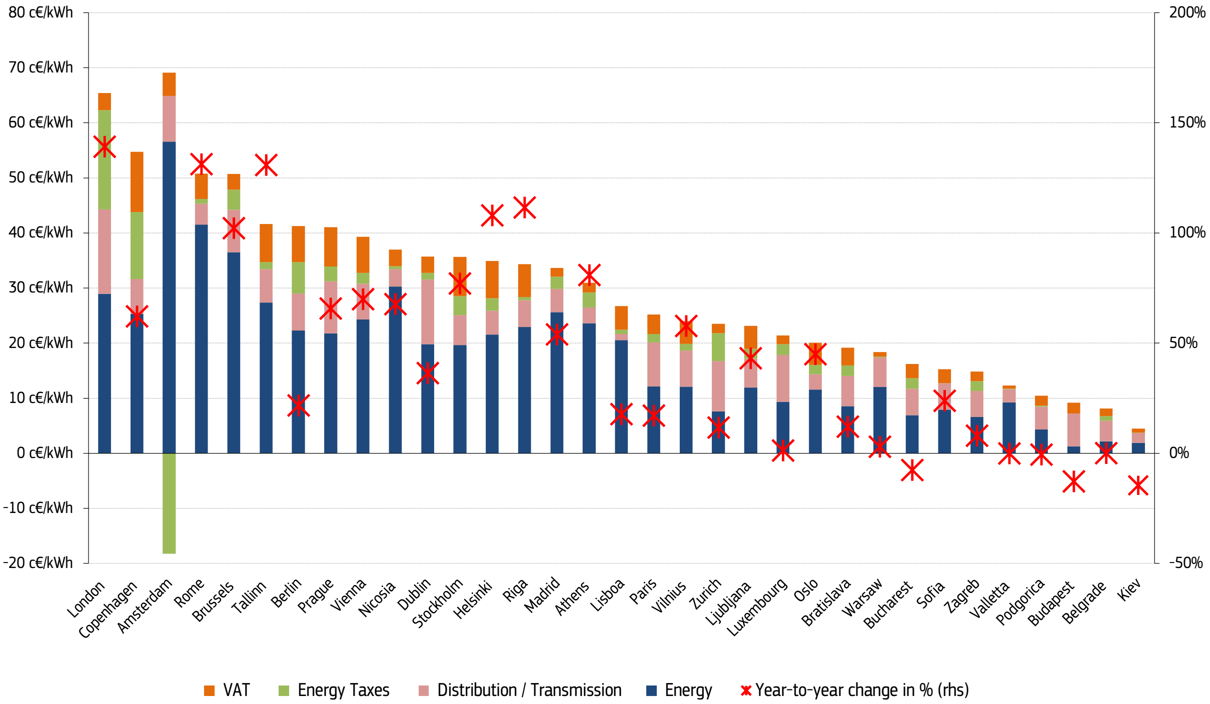
- The highest levels of the energy component in Europe were reported in Amsterdam, Rome, and Brussels (56.6, 41.5 and 36.5 c€/kWh). The lowest levels of the energy component (1-3 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Belgrade, Kiev and Budapest). The EU average for the energy component was 19.9 c€/kWh (up from 8.6 c€/kWh in August 2021).

- The highest network charges were recorded in London (15.3 c€/kWh), Dublin and Prague (11.8 c€/kWh and 9.4 c€/kWh, respectively) where they accounted between 23%-33% of the total price. The lowest network fees were collected in Lisbon (1.1 c€/kWh), Kiev (1.8 c€/kWh) and Valletta (2.3 c€/kWh). The EU average in the reference quarter was 5.8 c€/kWh (slightly up from 5.6 in August 2021).

- Apart from London (18.0 c€/kWh), the highest energy taxes were paid by households in Copenhagen (12.1 c€/kWh) and Berlin (5.7 c€/kWh). Sofia, Budapest and Kiev stood at the other end of the range, with practically zero energy taxes collected by local authorities. The average energy tax component reached 1.9 c€/kWh (down from 2.6 c€/kWh in August 2021). Varied VAT rates applied to electricity, ranging from 5% in Madrid, Valletta, Warsaw and London to 21-20% in Budapest, Copenhagen and Stockholm, also contribute to differences in household prices across Europe. Member States continue to use the measures included in the Energy Prices Toolbox to alleviate the effects of rising energy prices, in the form of lower energy taxes, levies and VAT applicable to household customers of energy.

- 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 53,** and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh.

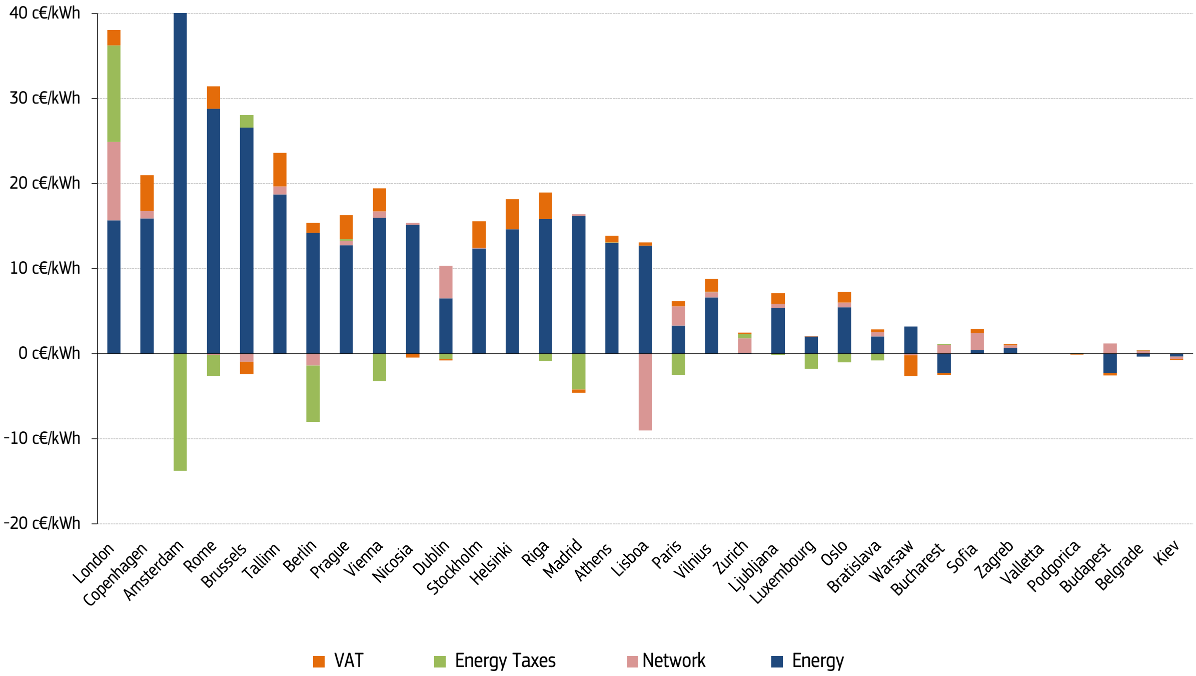
Figure 55 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, August 2022



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increase in relative terms in Europe in August 2022 were observed in London (+139%), Rome and Tallinn (+131%). As shown in **Figure 57**, rising prices were driven by increasing wholesale prices in practically every EU capital. Three of the twenty-seven EU capitals reported prices lower or unchanged, compared to the same month of the previous year, with Budapest (-13%) and Bucharest (-8%) posting the largest relative drops. Households in the Hungarian and the Romanian capital benefited mainly from a reduction in the energy component.

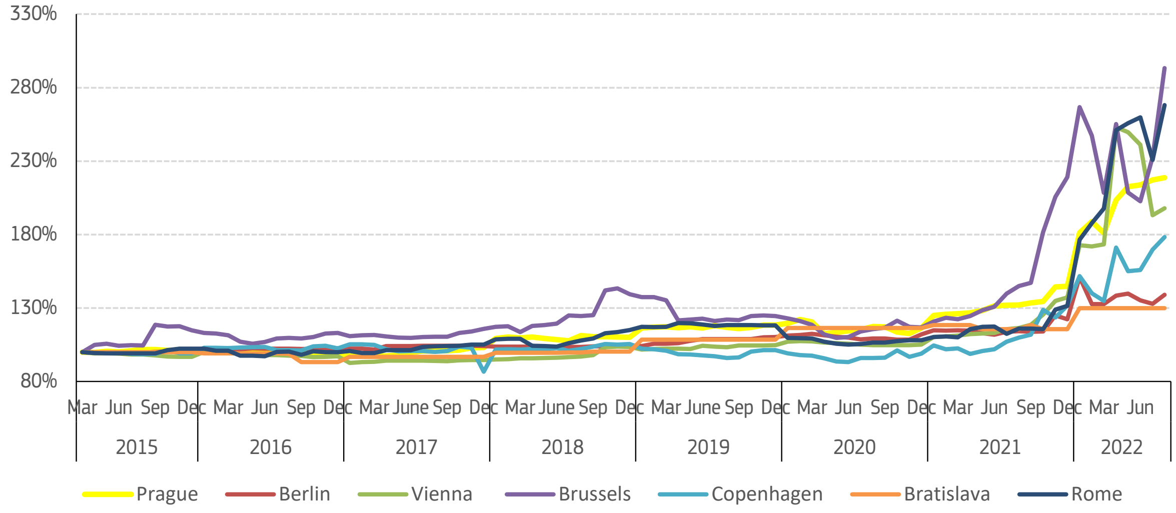
Figure 56 – Year-on-year change in electricity prices by cost components in the European capital cities comparing August 2022 with August 2021



Source: Vaasaett

- **Figure 58** compares how household retail prices in selected EU capitals changed in relative terms over the last seven years. The biggest increase in August 2022 (+293%) was registered in Brussels and was driven mainly by a rising energy component. Rome followed closely with a 268% increase since February 2015, followed by Prague (+219%) and Vienna (+198%). Retail prices for households in Copenhagen, which have been roughly the same as until the second half of 2021, have recently seen an steep increase (+178% compared to February 2015) due to a rise in the energy component. Bratislava and Berlin mark the smallest increases (130% and 139% respectively)

Figure 57 – Relative changes in retail electricity prices in selected EU capitals since 2015

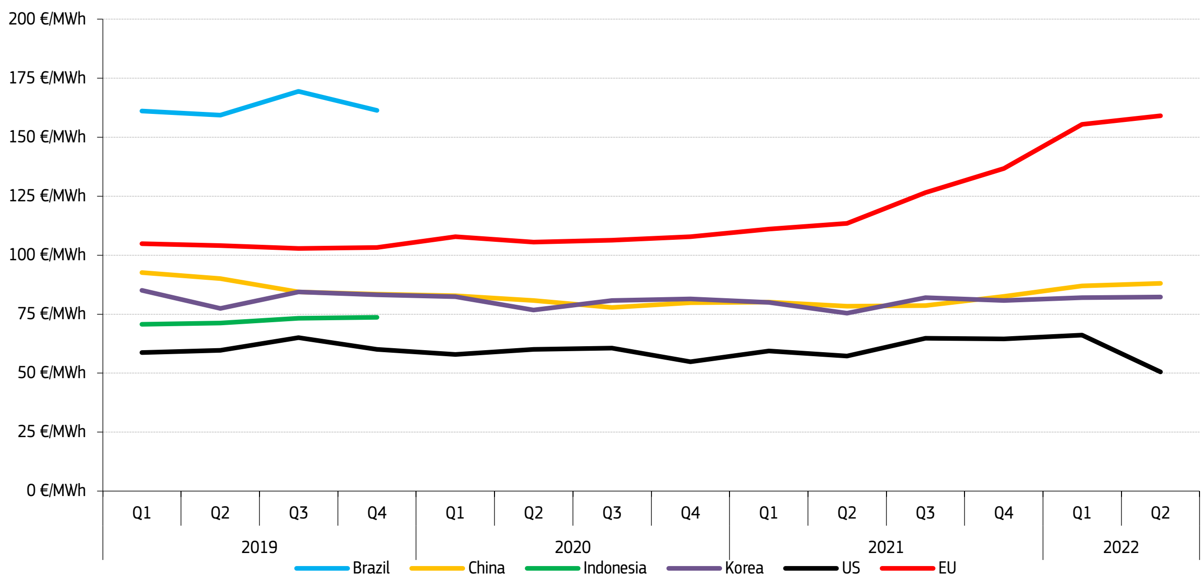


Source: Vaasaett

4.2 International comparison of retail electricity prices

- **Figure 59** 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 registered an increase of 40% in Q2 2022 compared to the equivalent quarter in 2021 and by 2% compared to Q1 2021. Meanwhile, Chinese industrial prices increased by 12% year-on-year, continuing to climb after a steady downward trend observed before 2021. Industrial electricity prices in the United States drop by 12% quarter-to-quarter in Q2 2022, falling by 24% compared to Q1 2021. As it can be observed, industrial retail electricity prices in the EU were higher compared to many of the global competitors, implying cost disadvantages for energy intensive industries.

Figure 58 – 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. Industrial prices in the EU are represented by the ID consumption band for the purposes of international comparison.

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 in the 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.

EP5 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 2021 shows the price for 2022; and the year-ahead curve in 2022, in turn, shows baseload prices for delivery in 2023.

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.