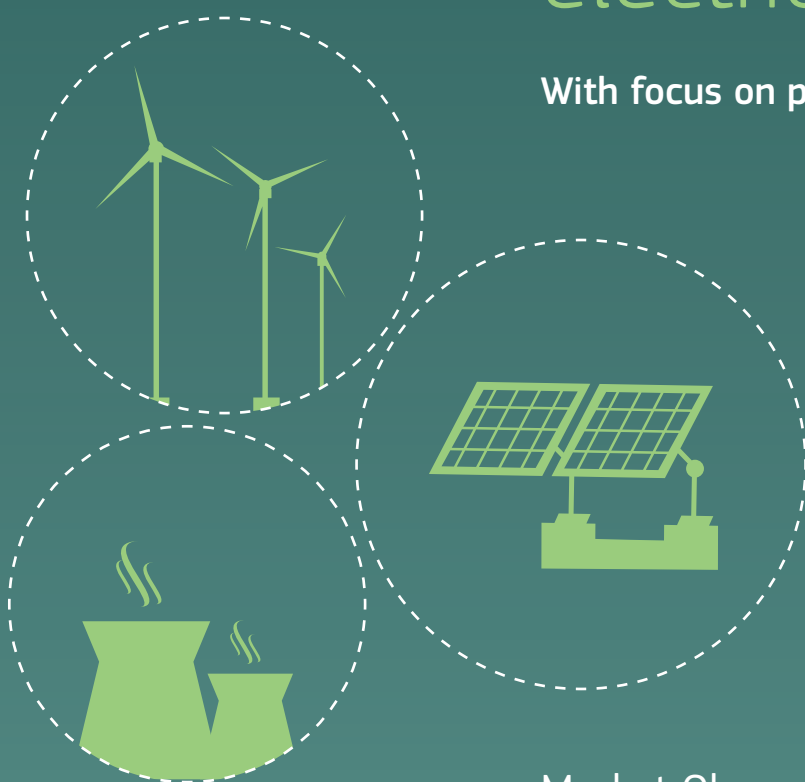


Quarterly report

On European electricity markets

With focus on price developments in 2022



Market Observatory for Energy
DG Energy

Volume 15

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DISCLAIMER: This report prepared by the Market Observatory for Energy of the European Commission aims at enhancing public access to information about prices of electricity in the Member States of the European Union. Our goal is to keep this information timely and accurate. If errors are brought to our attention, we will try to correct them. However, the Commission accepts no responsibility or liability whatsoever with regard to the information contained in this publication.

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Corrigendum: The original version of the report had incorrect figures for German and French EV sales on page 6. This has now been corrected.

HIGHLIGHTS OF THE REPORT

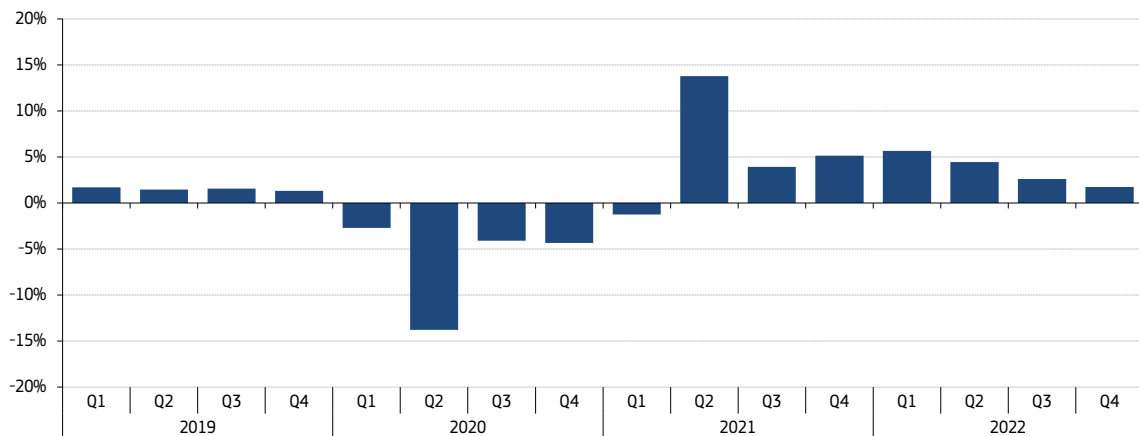
- **The fourth quarter of 2022 was marked by decreasing electricity consumption, due to demand destruction supported by a mild winter which delayed the start of the heating season in the EU.** Consequently, sustained by high storage levels, gas prices eased compared with summer levels, helping to alleviate wholesale electricity prices. However, nuclear generation remained low, putting upward pressure to a tight market, despite an increase in availability throughout Q4 2022. The higher-than-usual temperatures during the rest of the winter and storage levels supported a considerable fall in the price of gas (albeit at higher than historical levels) and, consequently, of electricity in the following months of 2023.
- **Wholesale electricity prices in European markets broke several records high during 2022, with an unprecedented peak in August.** The Russian war in Ukraine affected energy markets resulting in substantial increases in prices, volatility and uncertainty on energy supply. Record high gas prices, low nuclear fleet availability and reduced hydro output due to a drought, increased the pressure on the already tight market. **In 2022, the European Power Benchmark averaged 230 €/MWh, 121% higher than in 2021.** Italy had the highest baseload electricity prices (304 €/MWh on average) in 2022, followed by the Malta (294 €/MWh), Greece (279 €/MWh) and France (275 €/MWh).
- **Wholesale electricity prices in Q4 2022 were lower than in the previous quarter (Q3 2022), due to improved fundamentals in the gas market.** Lower demand and mild weather supported lower prices, but reduced nuclear power generation, continued to put upward pressure on wholesale electricity markets. The largest year-on-year price increases in Member States were registered in France (+342%), Austria (312%), and Slovakia (+310%). Prices in France were influenced by the low nuclear output and the reversal of net export power flows in the context of unprecedented high gas prices. The European Power Benchmark was 187 €/MWh on average in Q4 2022, 4% lower on yearly basis. Prices rose in nineteen markets in Europe. The highest prices during the quarter were recorded in Greece and Italy (246 and 245 €/MWh, respectively) and were 11% and 1% higher than in Q4 2021. The lowest quarterly average prices during Q4 2022 were recorded in Spain and Portugal at 113 €/MWh, 46% lower than in Q4 2021.
- **Electricity consumption in the EU fell (-9%) compared with last year's levels in Q4 2022,** due to the impact of the energy crisis, supported by a mild winter. **Moreover, in 2022, consumption across the EU fell by 3% compared with 2021,** following the impact of high electricity prices and the subsequent industrial demand reduction.
- **The share of renewables increased to 39% in 2022** (from 38% in 2021), while share of fossil fuels rose to 38% (from 36% in 2021). In 2022, solar generation rose by 26% (+41 TWh), onshore wind increased by 10% (+33 TWh) and offshore wind climbed by 4% (+2 TWh), reflecting the level of development of new capacity for these technologies. The combined solar and wind generation increased their output by 14% in 2022 (+76 TWh). However, subdued yearly hydro generation fell by 17% (-61 TWh) on a drought that affected Europe. Nuclear generation remained under pressure due to outages and delayed scheduled maintenance in France. Nuclear output fell by 17% (-118 TWh) in 2022.
- **Fossil fuel generation rose by 3% (+24 TWh) in 2022,** supported by reduced nuclear and hydro generation. In total, coal-fired generation increased by 6% (+24 TWh), whereas less CO₂-intensive gas generation rose slightly by less than 1% (+1 TWh). Rising gas prices made gas-fired power generation less economically favourable compared to coal-fired generation. Based on preliminary estimates, the 2022 carbon footprint of the EU power sector rose by 4% compared with 2021. However, despite this increase, the carbon footprint Q4 2022 is estimated to have decreased by 9%, due to reduced demand and lower fossil fuel generation.
- **A new record of installed renewable capacity was reached in the EU in 2022, as 57 GW of solar and wind capacity were added to the system - resulting in an increase of 16% on a yearly basis.** Additional installed capacity supported higher levels of renewables generation in 2022.
- **Carbon prices registered 80 €/tCO₂ in 2022, which was a 50% increase from the prices recorded in 2021.** High European Union Allowances (EUA) prices in 2022, were still insufficient to support coal-to-gas fuel switching in power generation, due to exceptionally high gas prices through most of the year.
- **High wholesale electricity prices resulted in rising consumer bills for households in 2022, impacting the industry sector as well.** The ease in wholesale prices registered in Q4 2022 alleviated the pressure on retail prices, while further reduction could be expected as prices fell substantially during the following months of 2023. Retail electricity prices for household costumers in EU capital cities were up by 17% in February 2023, compared with the same month in 2022. However, retail prices in February registered a fall for the fourth consecutive month, as a result of lower wholesale prices.
- **More than 695,000 new EVs were registered in the EU in Q4 2022,** an increase of 30% in comparison with same quarter in 2021. Demand for electrically vehicles (EVs) positioned Q4 2022 as the highest quarterly figure on record. Q4 2022 numbers translated into a 28% of market share, lower than China (35%), but more than three times higher than in the United States (8%).

1 Electricity market fundamentals

1.1 Demand side factors

- Figure 1** shows the GDP annual growth in the European Union. According to the March 2022 Eurostat estimate, seasonally adjusted GDP increased by 1.7% year-on-year in the EU between October and December 2022 (after +2.6% in the EU in Q3 2022). Moreover, GDP in the EU increased by 3.5% in 2022, after 5.4% in 2021. The economic recovery registered in the first half of 2022 slowed down in the second half of the year, amid high energy pressure and elevated inflation (10.4% of EU annual inflation in December 2022, energy was responsible for contributing 2.79 percentage points to this figure). Moreover, as high electricity prices prompted the decreased use of electricity in energy-intensive sectors, the increase in economic activity did not really translate in higher electricity consumption in the EU. Compared with Q4 2021, annual growth registered positive figures in 23 of 27 Member States. The highest annual rates were reported in Ireland (+13.1%), followed by Greece (+5.2%) and Romania (+4.7%). The highest year-on-year decreases were observed in Estonia (-4.4%) and Luxembourg (-2.2%).

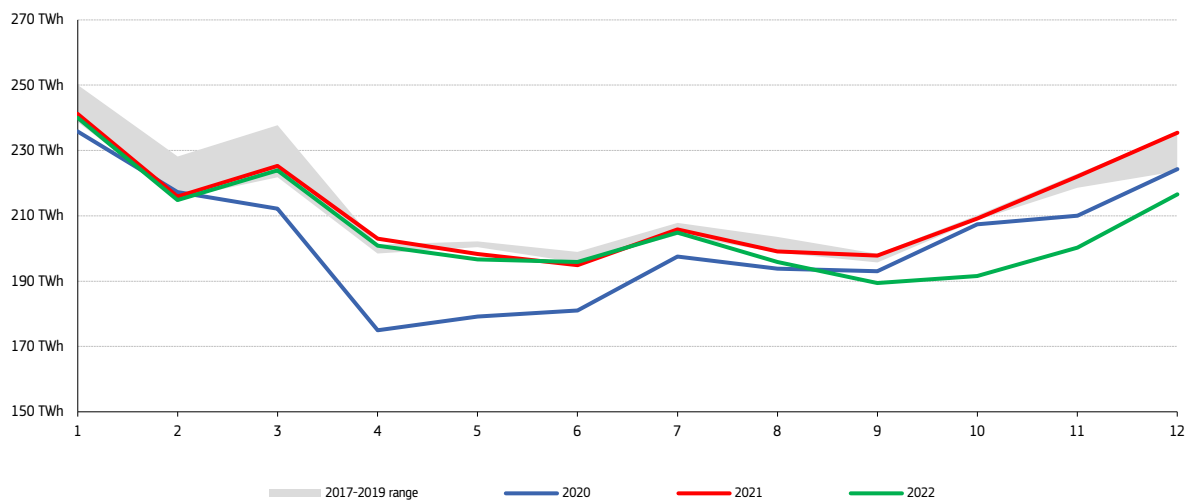
Figure 1 – EU GDP annual change (%)



Source: Eurostat

- According to Eurostat, the electricity consumption in the EU dropped 8.7% compared with last year's levels in Q4 2022, following the impact of high electricity prices and the subsequent industrial demand reduction. Demand levels for the fourth quarter of 2022 were also well below the 2017-2019 range, registering the lowest value in October (even lower than in October 2020) and the highest in December (still below December 2020).

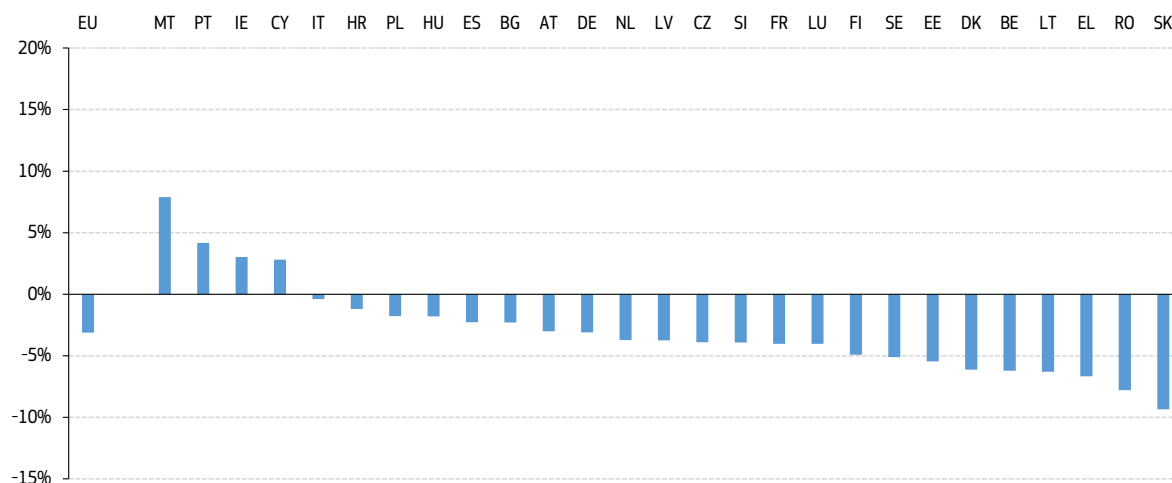
Figure 2 – Monthly EU electricity consumption



Source: Eurostat

- **Figure 3** sums up changes in electricity consumption over 2022, compared to 2021. EU electricity consumption fell due to the unprecedented electricity prices in 2022, which supported a decrease in household energy demand and a relevant demand destruction from industries. Overall, large industrial consumers, responsible for the biggest portion of the demand, struggled with high energy prices, resulting in a considerable decrease of the consumption. Twenty-three Member States registered decreases in consumption, the biggest of which occurred in Slovakia (-9%), Romania (-8%) and Greece (-7%). By contrast, Malta (+8%) and Portugal (+4%) registered increases linked to cooling needs due to warm weather in summer. Compared with 2021, EU-wide consumption fell by 3%.

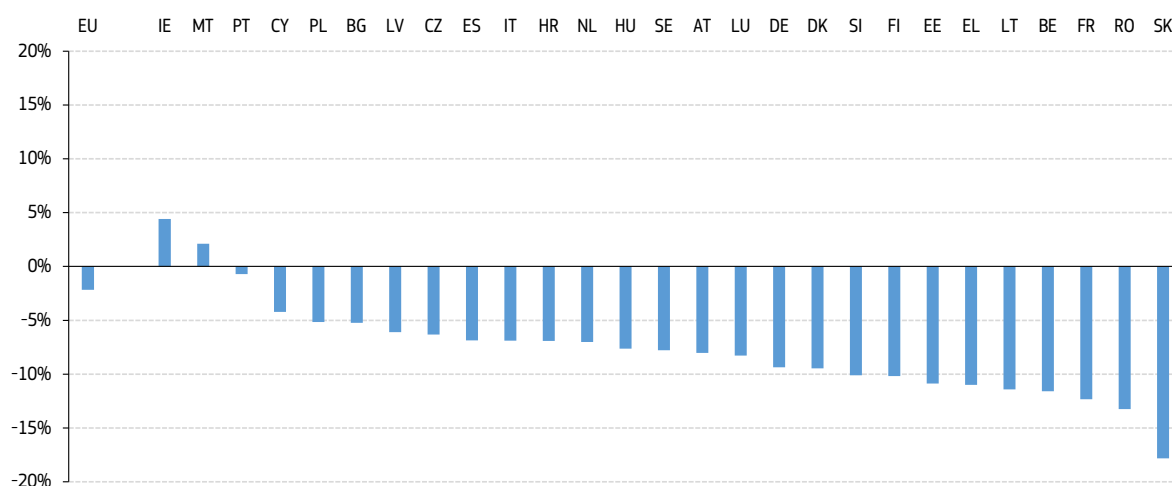
Figure 3 – Annual changes in electricity consumption in 2022 by Member State



Source: Eurostat

- **Figure 4** sums up changes in electricity consumption over the fourth quarter of 2022, compared to Q4 2021. EU average hides wide differences of developments in individual Member States during the reference quarter. Only two Member States saw an increase in consumption year-on-year, registering moderate grows in Ireland (+4%) and Malta (+2%). In addition, twenty-five Member States registered a drop in consumption, led by Slovakia (-18%), Romania (-13%), France and Belgium (-12%). Of the major economies, power consumption also went down in Germany (-9%) and in the Netherlands (-7%). The mild 2022/2023 winter contributed as well to a decrease in demand (see **Figure 5**).

Figure 4 – Annual changes in electricity consumption in Q4 2021 and Q4 2022 by Member State

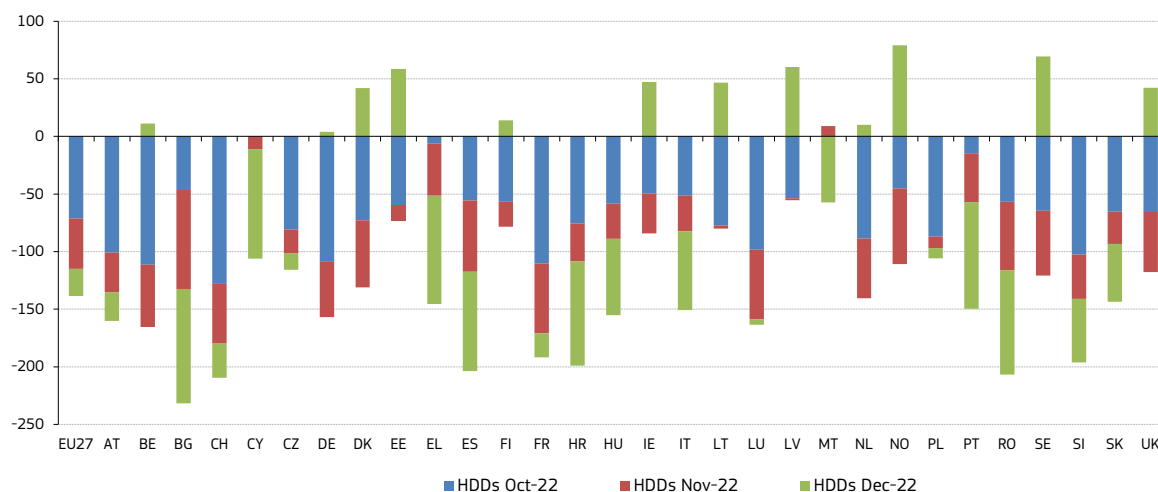


Source: Eurostat

- **Figure 5** illustrates the monthly deviation of actual Cold Degree Days (CDDs) and Heating Degree Days (HDDs) from the long-term average (a period between 1979 and the last calendar year completed) in Q4 2022. EU-wide, the

reference quarter was warmer than the historical range, registering 139 HDDs below the long-term average (concentrated mainly in October). In general, temperatures during Q4 2022 were approximately 1.5°C higher than usual, mainly due to warmer weather in October. Practically all MS experienced warmer-than-usual weather conditions, with the exception of Nordic and Baltic countries in December, where cold temperatures were registered. During the reference quarter, all three months registered warmer-than-average temperatures. In particular, October had the highest number of deviations from the average levels. Overall, among other relevant factors, the mild weather helped keeping the energy price situation from worsening during the fourth quarter of 2022.

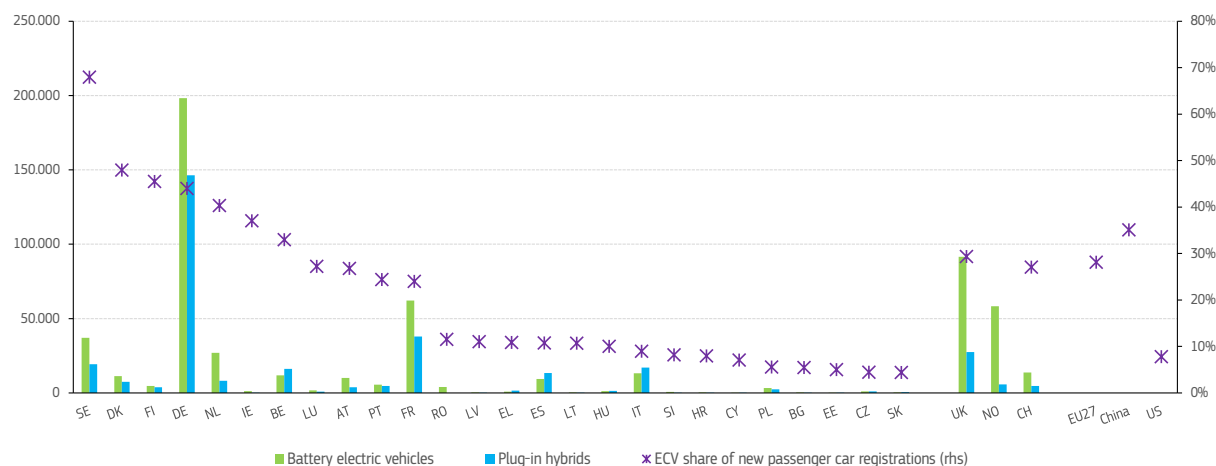
Figure 5 - Deviation of actual heating days from the long-term average in October-December 2022



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

- **Figure 6** shows that almost 695,000 new EVs were registered in the EU in Q4 2022 (+56% compared with Q3 2022 and +30% year-on-year). This is the highest quarterly figure on record and translates into a 28% market share; lower than China (35%), but more than three times higher than in the United States (8%). The battery electric vehicles segment continued to grow (+31% year-on-year above 406,000) together with an increase in the demand for plug-in hybrid vehicles (+29% year-on-year to almost 287,000) for the first time since Q3 2021. Hybrid electric vehicles (not chargeable) sales amounted to 545,000, lower than the EV category, but still registering an increase of 22% compared with Q4 2021. EU proposals linked to Green Deal initiatives and national policies continue to support the adoption of EVs in Europe.
- The highest EV penetration was observed in Sweden for another consecutive quarter, with an outstanding record of 67%, 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 January 2023, new CO₂ limits for the climate bonus are in place, increasing the emissions requirement to opt for this bonus. In addition, in Denmark, almost half of the passenger cars sold could be plugged (48%), while in Finland 46% of the Q4 2022 car sales were EVs, followed by Germany (44%). Germany retained the position of the largest individual market (close to 345,000 EV sales in Q4 2022) thanks to its generous incentive programme, which since 2020 and until the end of 2022, offered up to €9,000 in direct purchase bonuses. After Germany, numbers in EVs were also supported by France, where sales amounted to more than 100,000 new EVs in the reference quarter.

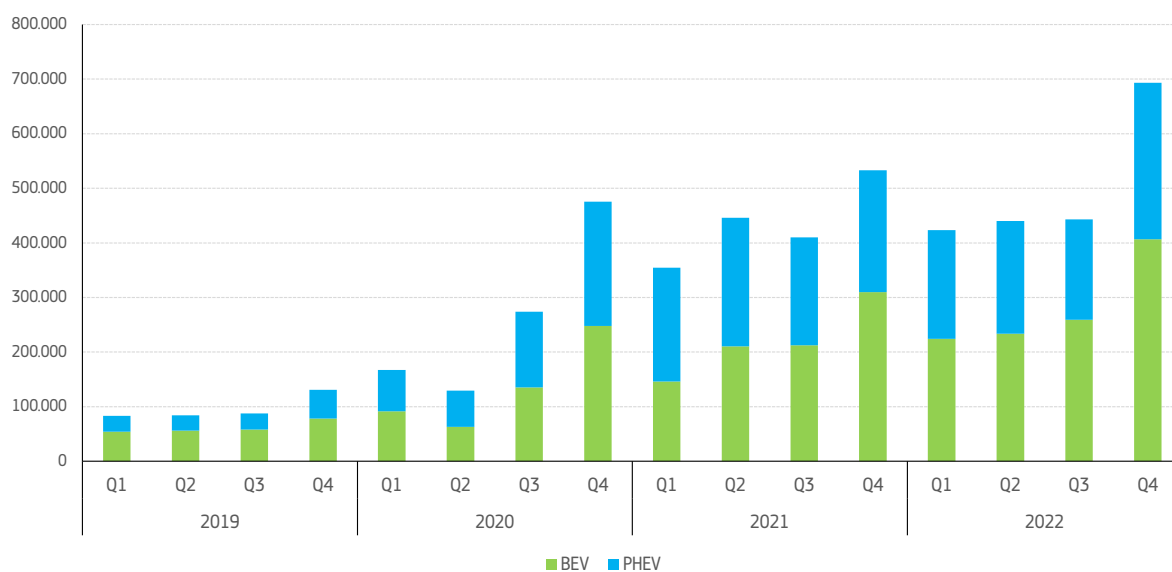
Figure 6 – Electrically chargeable passenger vehicle (EV) sales in selected countries in Q4 2022



Source: ACEA, CPCA, BloombergNEF

- **Figure 7** shows how the rapid expansion of electric vehicles in Europe unfolded in 2021 and continued in 2022. Policy support and additional stimulus measures have contributed to the increase in EV numbers. As the number of EVs on European roads is expected to continue growing fast in the years ahead, so will its impact on electricity demand and network load. In addition, the increase in demand and further constraints in the supply chain of batteries risk slowing the rollout of EVs in the near future.

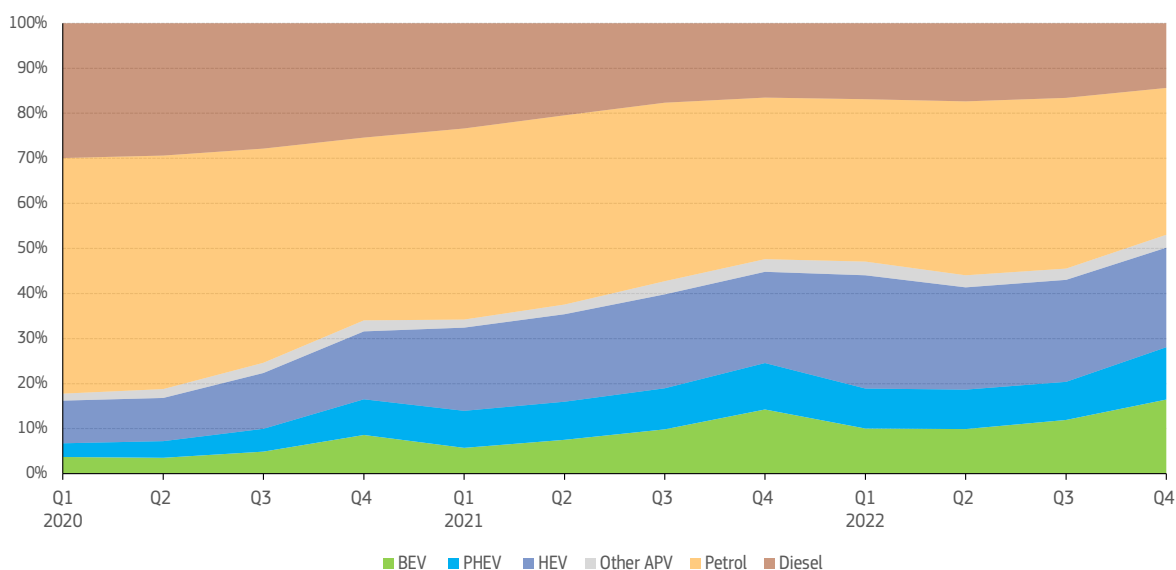
Figure 7 – Quarterly EV sales in the EU



Source: ACEA

- **Figure 8** shows the decline of sales of diesel cars, which saw their market share fall to 14% in Q4 2022, from 17% in Q4 2021. Petrol car sales experienced a fall in their share to 33% in Q4 2022, from 36% in the fourth quarter of the previous year. On the other hand, the share of new Hybrid electric vehicles (HEV) in the market increased from 20% in Q4 2021, to 22% in Q4 2022. The share of new EVs has also risen year-on-year (from 25% in Q4 2021 to 28% in Q4 2022).

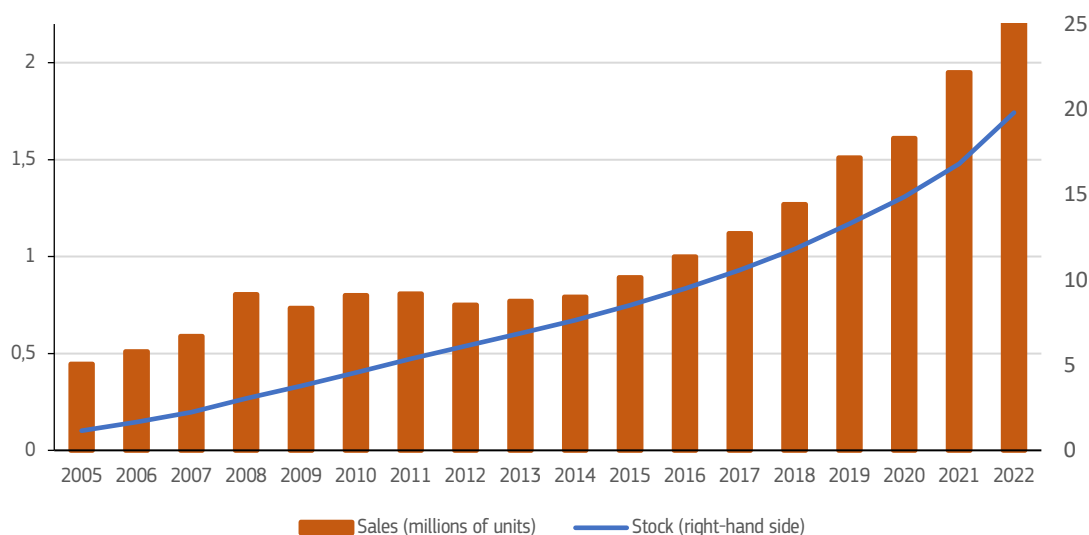
Figure 8 – Evolution of quarterly drivetrain shares in the EU



Source: ACEA

- **Figure 9** shows the evolution of Heat Pumps sales across Europe reported by the European Heat Pump Association (EHPA), breaking a record of sales of around 3 million new units sold in 16 markets in Europe in 2022. Heat pumps are commonly used for heating, hot water and even in some cases, for cooling. Heat pumps enable the use of renewables (ambient heat) in the heating sector and are more efficient than boilers. REPowerEU plan seeks to double the annual pace of deployment, mainly replacing gas boilers in an additional 10 million buildings over the next five years, and 30 million by 2030.
- In total, the current heat pump stock amounted to almost 20 million in Europe, by the end of 2022. Annual sales grew around 38% in 2022.

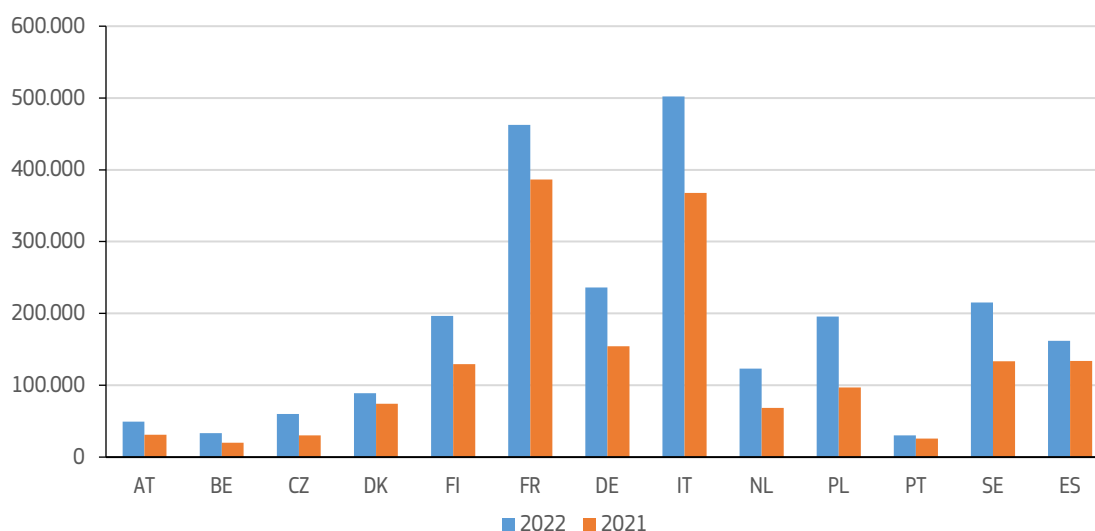
Figure 9 – Yearly Heat Pump sales in Europe



Source: EHPA

- **Figure 10** shows detailed amount to heat pump sales in selected Member States during 2022. The main increase in sales during 2022, compared with 2021, was registered Poland (+100%), Czechia (+99%) and the Netherland (+80%). In absolute terms, the largest number of sales were seen in Italy (over 500 thousand new heat pump units), France and Germany.

Figure 10 – Sales of Heat Pumps in 2022 in selected Member States



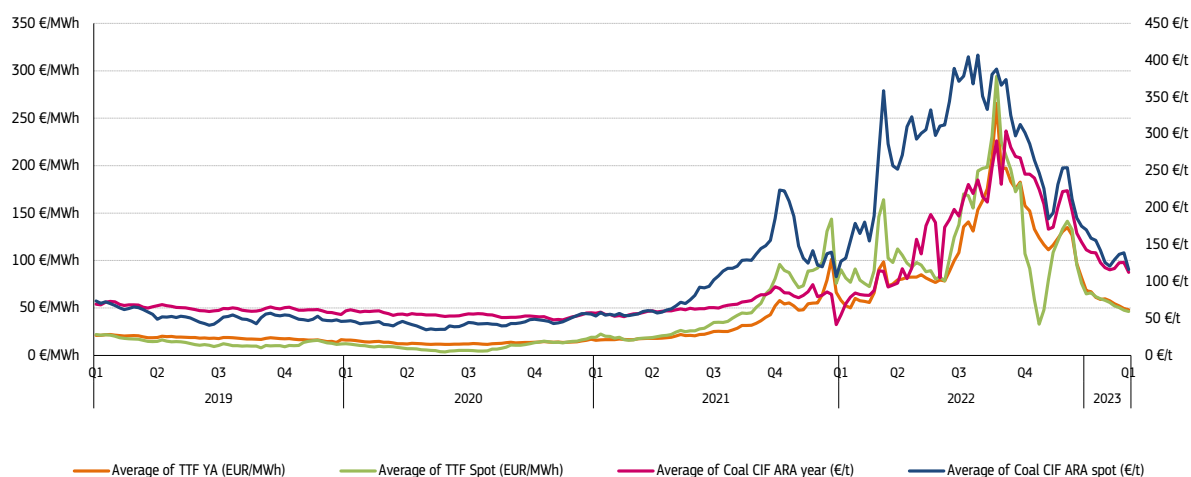
Source: EHPA

1.2 Supply side factors

- Figure 11** reports on developments in European coal and gas prices. In 2022 both gas and coal markets remained subject to volatility in the spot market. The Russian invasion in Ukraine and related international sanctions (including reluctance from companies to purchase Russian fossil fuels) affected already tight energy markets resulting in substantial increases in prices, volatility and uncertainty on energy supply. In October, prices of gas fell to pre-crisis levels (before July 2021) for the first time reflecting an oversupplied market with high storage volumes. Spot prices diverged at lower levels than forward contracts. Prices surged again in November to new highs on the back of the delayed start of the heating session in Europe, translating into higher gas demand, intensifying of storages withdrawals and an alignment of spot and forward contracts. Finally, prices plunged in the second half of December on favourable fundamentals: underground storages still being close to maximum capacity in most Member States, continued high deliveries of LNG (e.g. new Eemshaven terminal in the Netherlands) at prices lower than TTF and reduced demand in line with policy action, warmer-than-average temperatures and demand destruction.
- In October, the Commission proposed [new emergency regulation](#) to address high gas prices strengthen security of supply of gas via joint purchasing, default solidarity, a new pricing reference benchmark for LNG, and a temporary collar to prevent extreme spikes in derivative markets. It also proposed a [Market Correction Mechanism](#) to protect consumers from episodes of excessively high gas prices. On 19 December, the [Energy Council](#) agreed on the Commission proposals to seek developing a joint purchasing and efficient use of gas infrastructure, a new LNG benchmark to bring more transparency to the gas markets, a solidarity default rules on financial compensation, and a market correction mechanism to limit excessive gas prices. On 20 March, the Commission proposed to extend the coordinated [demand reduction for gas rules](#) (by 15% for another 12 months).
- Spot gas prices averaged 95 €/MWh in Q4 2022, 52% lower than the previous quarter (Q3 2022) and just 1% higher than prices in Q4 2021. On 1 November, gas prices registered 24 €/MWh on the back of a combination of unexpected warm weather, significant demand destruction and a shortage of storage capacity. Conversely, on 7 December, gas prices closed at 149 €/MWh reflecting increased demand due to low temperatures in Europe, supported by outages of Norwegian gas assets. Forward prices registered a contango during the first part of Q4 2022, corrected with the delayed start of the heating season translating into higher gas demand and storage withdrawals. EU storages reached a peak of 95% during the second week of November. Spot and forward prices remained at downward trend for most part of Q1 2023, driven by improved market fundamentals (i.e. high storage levels, reduced demand and additional LNG regasification capacities in Europe).
- After supporting gas-to-coal switch for most of 2022, the reduction of gas prices in October and at the end of Q4 2022, has closed the gap between coal- and gas-fired generation. The further decline in gas prices, combined with high carbon prices in Q1 2023, has supported gas-fired generation vis-à-vis coal-fired power plants. 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, fell to 234 €/t in Q4 2022 (from the high levels recorder in the previous quarter). Prices fell by 35% compared with the previous quarter (Q3 2022) and amounted for a 49% growth compared with Q4 2021. Coal price was on a marked decreasing trend since September, despite tight energy markets and gas-to-coal switch, supported by increased levels of imports in line with supply diversification efforts. In December, coal prices fell to levels before the Russian war in Ukraine, due to mild winter temperatures and ample coal stocks.
- As a result of sanctions, imports of coal from Russia halted since 10 August, although suppliers were already looking for alternative sources to replace Russian coal in the previous months. Some Member States put in place short-term policies to allow for more coal to be used for producing electricity to replace Russian gas used for power generation. The German government delayed the closure of 8.6 GW of coal power plants, while the Dutch government lifted on 20 June the production restrictions that limited coal-fired generation load factors to 35%, as part of the country's gas crisis plan.
- Coal prices continued the fall in the following months (Q1 2023) supported by increased levels of imports in line with the supply diversification efforts, as well as the improvement of local coal production in some Member States (e.g. Poland) and high level of gas storages which supported lower gas prices in the EU.

Figure 11 – 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 12**, continued registering high levels of price volatility in Q4 2022 driven by downward pressure coming from industrial and consumer demand destruction and from the other side, upward pressure from greater coal-fired generation which increases demand for emission allowances. Carbon prices hovered around 70-85 €/tCO₂ during most part of Q4 2022, reaching a high of 90 €/tCO₂ on 12 December, as low temperatures led to rising demand, increasing fossil fuel generation and demand for allowances.
- The average spot price of CO₂ in Q4 2022 (77 €/tCO₂) registered an increase of 12% compared with Q4 2021 and a 3% decrease in relation to the previous quarter (Q3 2022). Under 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 24**). However, lower gas prices in October, end of 2022 and Q1 2023, are supporting coal-to-gas fuel switch. In recent years (2020) high carbon prices put coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors.
- In 2022, the average spot price of CO₂ registered 80 €/tCO₂, which was a 50% increase from the prices recorded in 2021. High European Union Allowances (EUA) prices in 2022, were still insufficient to support coal-to-gas fuel switching in power generation, due to exceptionally high gas prices throughout the year.

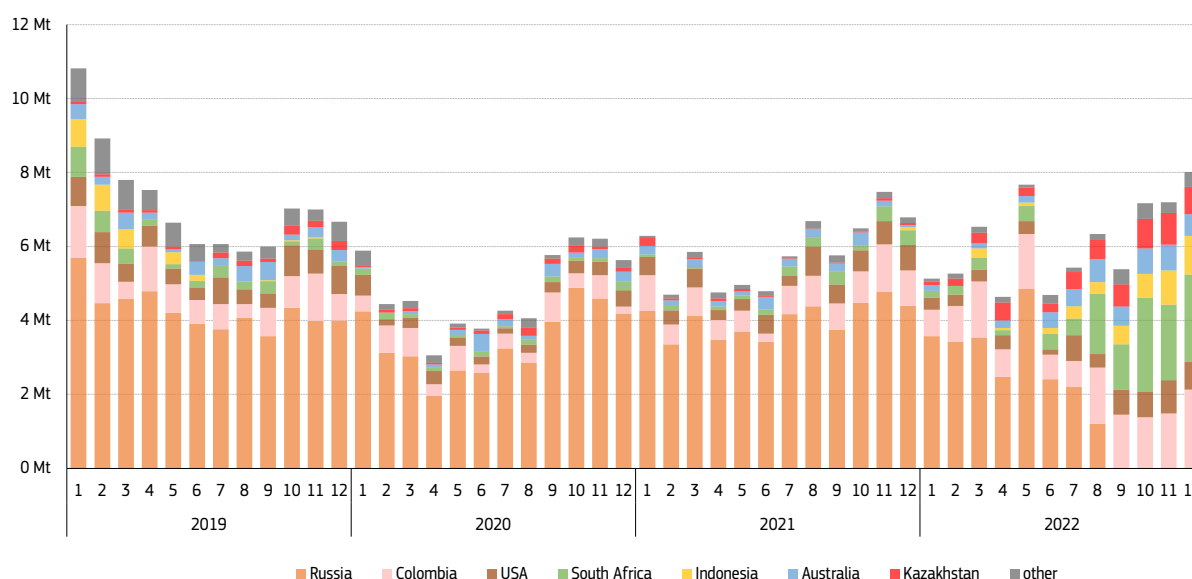
Figure 12 – Evolution of emission allowance spot prices from 2019



Source: S&P Global Platts

- As visible from **Figure 13**, monthly average thermal coal imports into the EU held at roughly 7.5 Mt in Q4 2022, as high gas prices supported more running hours for coal-fired generation. The total volume of imports increased by 8% year-on-year to 22 Mt in the fourth quarter of 2022. For the whole year of 2022, EU thermal coal imports increased by 4% compared with 2021 (73 Mt). The estimated EU import bill for thermal coal amounted to €6.5 billion in the reference quarter, 106% higher compared to Q4 2021, enhancing the year-on-year increase in imported volumes due to higher contracted prices of this commodity. The estimated 2022 import bill for thermal coal increased by 166% to €19.9 billion.
- The largest part of extra-EU thermal coal imports in Q4 2022 came from South Africa which accounted for 31% of the total imports, amounting to a 26% increase compared with Q4 2021. In light of the invasion of Russia in Ukraine, 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. Without Russian coal in the European market, international competitors are starting to increase their shares in imports to the EU. Consequently, along with South Africa, other countries registered an increase of thermal coal deliveries in Q4 2021: Indonesia recorded an increase in imports of 11 p.p. (12% share of the total imports), while Colombia saw its imports grow by 8 p.p. (22% share of the total) in the fourth quarter of 2022. The share of deliveries from US ports increased from 9% to 10%, while the share of imports from Kazakhstan and Australia reached shares of 10 and 11%, respectively during the reference quarter.

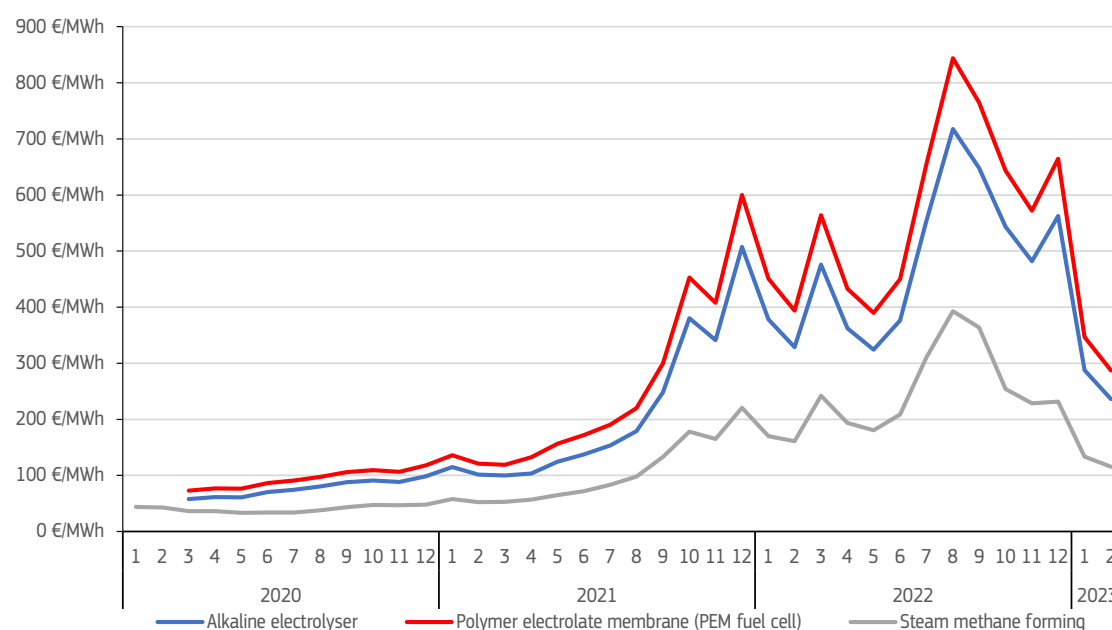
Figure 13 – Extra-EU thermal coal import sources and monthly imported quantities in the EU



Source: Eurostat

- Figure 14** presents the production cost-based estimates prices for hydrogen, generated by three different technologies. Alkaline water electrolysis, Polymer Electrolyte Membrane (PEM) and Steam Methane Forming (SMR). Alkaline water electrolysis is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). A Polymer-electrolyte Membrane (PEM) (or proton exchange membrane) is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes. Steam Methane Forming (SMF) refers to a technology for producing hydrogen from natural gas. For this latter technology, the chart below also includes the costs of Carbon Capture and Storage (CCS).
- Alkaline electrolysis and PEM technology costs predominantly depend on the electricity price, while the cost of SMR technology is driven by the cost of natural gas used for producing hydrogen. Alkaline and PEM are related to renewables generation (hydrogen generation cost assessment is practically based on green power costs, adding EU wind guarantee of origin prices to wholesale electricity prices), whereas costs of SMR hydrogen generation is based on costs of natural gas (by adding CCS costs).
- Cost-based assessment price for alkaline technologies averaged 506 €/MWh during Q4 2022, falling to 239 €/MWh during January and February 2023 (including CAPEX costs), whereas prices of PEM fuel cell technology-based generation averaged 584 €/MWh in Q4 2022, dropping to 276 €/MWh during January and February 2023. Elevated wholesale electricity prices in Q4 2022 (especially in December) impacted on the cost of these two hydrogen technologies. SMR technology based costs assessment averaged 212 €/MWh in Q4 2022, plunging to an average of 100 €/MWh in January and February 2023, on the fall of wholesale gas prices in the first months of 2023.

Figure 14 –Production cost-based hydrogen price assessment for different technologies (including CAPEX)



Source: S&P Platts. The calculated prices reflect both the commodity production cost and the capital expenditure associated with building a hydrogen facility.

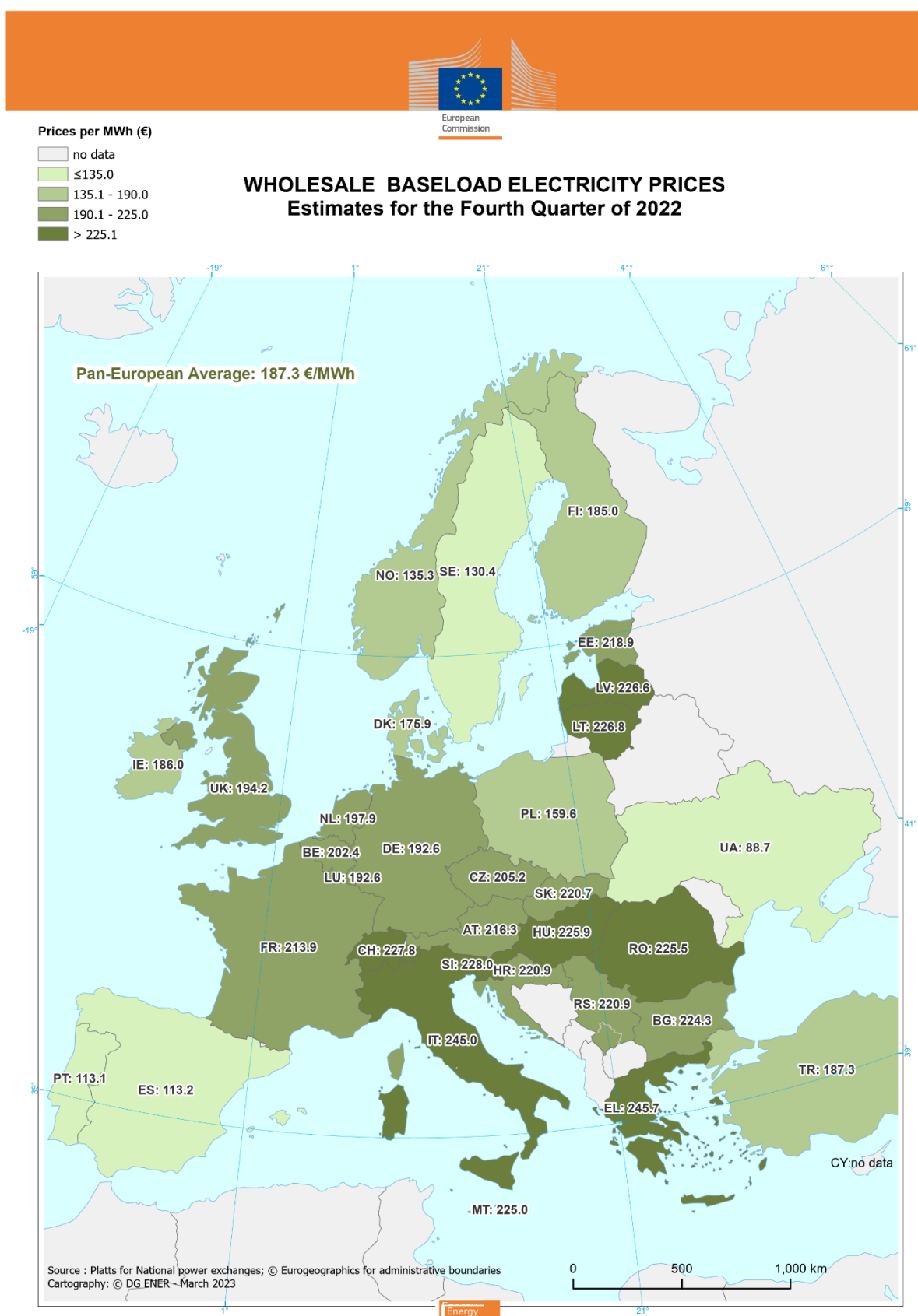
2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page (**Figure 15**) shows average day-ahead wholesale electricity prices across Europe in Q4 2022. The year 2022 registered the highest average power prices ever in European markets. However, prices in Q4 2022 were lower than in the previous quarter due to improved fundamentals in the gas market. Storages levels remained high in most Member States and LNG deliveries continued to arrive in the EU terminals. Additionally, reduced demand from consumers and industries due to demand destruction and policy action, along with warmer-than-average temperatures, contributed to the decrease in prices. Reduced nuclear fleet generation, albeit higher than in Q3 2022, continued to put upward pressure on wholesale electricity markets during Q4 2022. The delay in the start of the heating session and the filling of underground storages supported the fall in the price of gas and, consequently, of electricity in the first months of the following quarter. However, prices bounced back with the start of the first cold snaps in Europe to finally plunged in the second half of December due to favourable gas market fundamentals, lower demand and warmer-than-expected temperatures. In the following months, falling gas prices, lower demand and high renewables generation contributed to lower prices in the wholesale electricity market, albeit still at prices high in comparison with pre-crisis levels.
- On a yearly basis, nineteen wholesale electricity markets in Europe experienced a surge in prices, while six registered a decrease (changes ranged from approximately -45% to +60%¹) in Q4 2022. Greece and Italy reported the highest quarterly average price (246 and 245 €/MWh, respectively), 11% and 1% higher than in Q4 2021. Slovenia became the third most expensive market with an average baseload price of 228 €/MWh, which was 2% higher compared to the same period last year. The lowest quarterly average prices during Q4 2022 were recorded in Spain and Portugal at 113 €/MWh, 46% lower than in Q4 2021.
- The European Power Benchmark averaged 187 €/MWh in Q4 2022, 4% lower on yearly basis. Compared to Q3 2022, the quarterly average price fell by 45%.
- The largest year-on-year price increases in Member States were registered in France (+342%), Austria (312%), and Slovakia (+310%). Prices in France were influenced by the low nuclear output and the reversal of net export power flows in the context of unprecedented high gas prices. Conversely, Portugal and Spain experienced the lowest increase in prices during Q3 2022 (+25%) followed by Sweden (+75%).
- In 2022, the European Power Benchmark averaged 230 €/MWh, 121% higher than in 2021. Italy had the highest baseload electricity prices (304 €/MWh on average) in 2022, followed by the Malta (294 €/MWh), Greece (279 €/MWh) and France (275 €/MWh).
- Following the adoption of the [REPowerEU plan](#) in 2022, to rapidly reduce dependence on Russian fossil fuels and fast-forward the green transition and other measures for gas storage and reduction target, the [Council adopted](#) in October, [new emergency market intervention](#) measures proposed by the Commission in September (electricity demand reduction measures, cap on market revenues for inframarginal generators, solidarity levy for the fossil fuel sector and retail measures for SMEs). On 18 October, the Commission proposed [additional measures](#) to address high gas prices and a [new instrument to limit excessive gas price spikes](#) on 22 November. In addition, on 14 March 2023, the Commission proposed a reform of the EU electricity market, designed to boost renewables, provide better protection to consumers and enhance industrial competitiveness. The proposed reform aims to reduce the of fossil fuel prices on electricity bills by promoting long-term contracts for renewable energy and increasing flexibility of the system. Moreover, the reform seeks to incentivise investment in renewables by providing stable long term pricing agreements. The reform also seeks to support electrification of the industry and boost Europe's position as a global leader in net-zero technologies. The proposed reform foresees revisions to several pieces of EU legislation, notably the Electricity Regulation, the Electricity Directive, and the REMIT Regulation. The reform will be discussed and agreed by the European Parliament and the Council before entering to force.

¹ Five EU MS experienced increases over 50%, while two MS saw a decrease of over 40%, compared to Q4 2021.

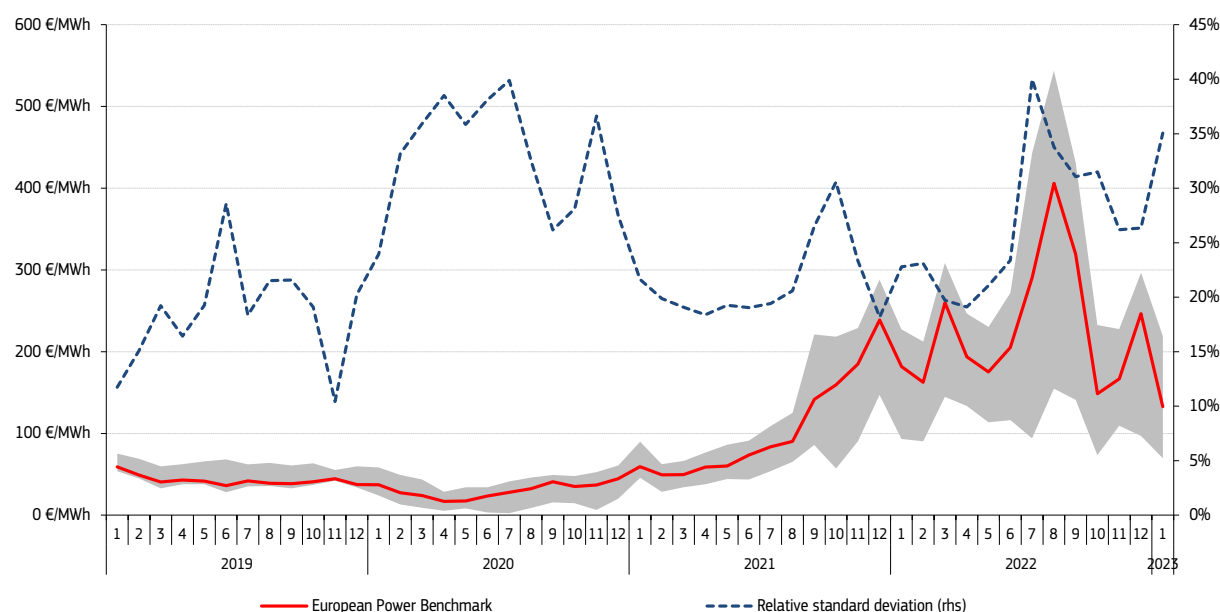
Figure 15 – Comparison of average wholesale baseload electricity prices, fourth quarter of 2022



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 16** 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 bounced back from a fall registered during Q3 2022, as the supply-demand balance developed differently in individual regions during the reference quarter. Central Western European markets decreased their coal-fired generation and gas-fired output, as demand was lower during the reference quarter. The relatively lower availability of the French nuclear fleet continued to put upward pressure on prices and reversing power flows away from the historical net exporting position of France. The phase-out of coal and nuclear capacity is increasing the sensitivity of power prices to the developments of the gas market. Reduced hydropower output in the Nordic markets, combined with the tightness of the continental European markets, resulted in an increase in prices. Elevated gas prices in Greece and Italy combined with tight supply margins, made these two markets the most expensive in Europe.

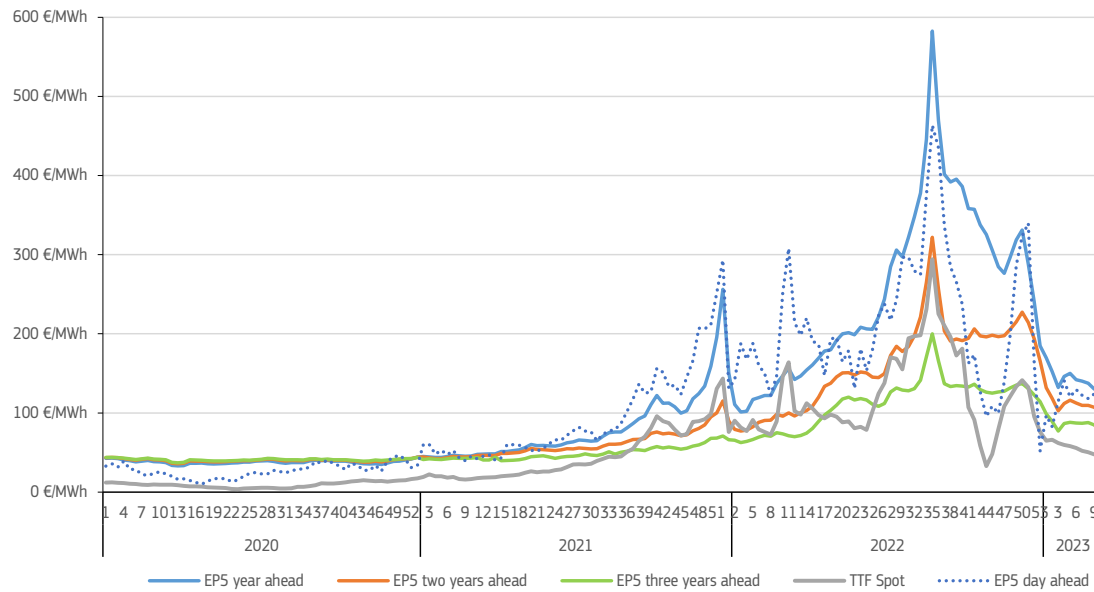
Figure 16 - The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- **Figure 17**, shows the how of gas prices (TTF spot price) has been driving 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. TTF spot price started bouncing back again in November 2022, on the back of the delayed start of the heating session in Europe, translating into higher gas demand. In mid-December, TTF prices fell thanks to high storage levels, increased LNG deliveries and reduced demand from consumers and industry, combined with warm-than-average weather. Consequently, the year ahead power benchmark followed TTF developments, rising to a weekly average of 330 €/MWh, following the first cold snaps of the heating session in early December. From that point, year-ahead power benchmark prices started to fall again following favourable fundamentals of the TTF. This trend continued into the first quarter of 2023.
- During the first week of Q4 2022, the electricity year-ahead, two-year ahead and three-year ahead contracts were respectively 358 €/MWh, 194 €/MWh and 133 €/MWh, whereas during the last week of December, these three values were at lower levels (185 €/MWh, 166 €/MWh and 114 €/MWh). The discount of the weekly average of the year-ahead contract to the spot market oscillated between -8 €/MWh and -230 €/MWh during Q4 2022. The contango for most of the reference quarter reflected the risks of potential tightness in the market, which did not materialise in the first quarter of 2023. However, the risk of market becoming tight again is still present, due factors such as the very low Russian pipeline supply to Europe, potential bad weather and possible rise in Asian LNG demand.

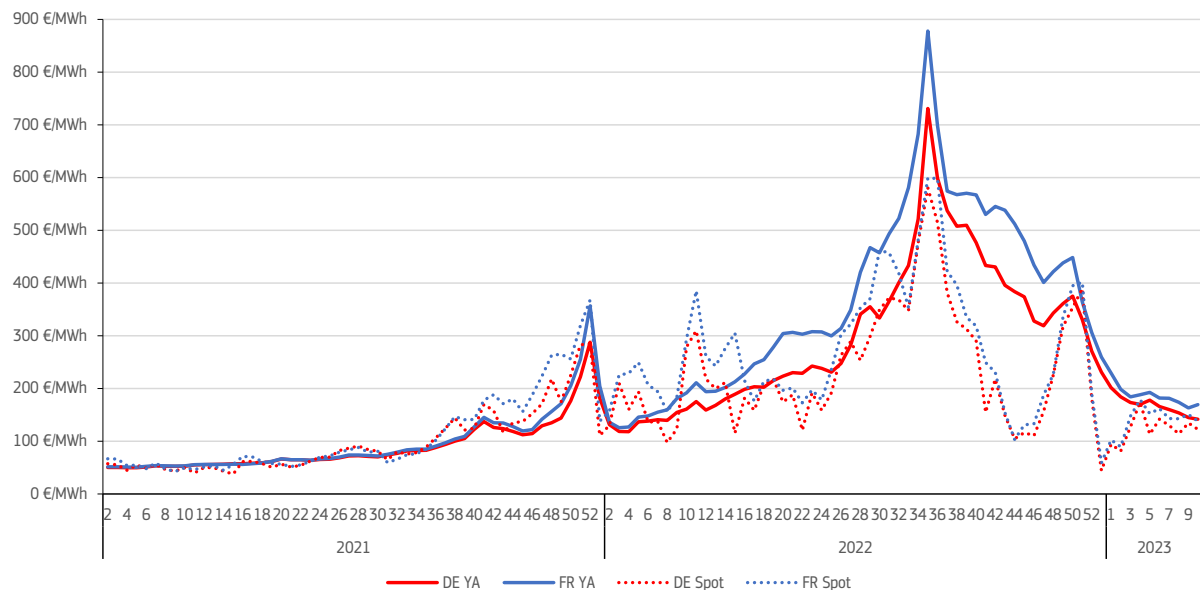
Figure 17 – Weekly futures baseload prices – weighted average of selected European markets



Source: S&P Global Platts.

- **Figure 18** 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 2022, reflecting structural differences between the two markets (i.e. the high proportion of French nuclear power plants under maintenance and the relevance of wind generation when can cover a significant part of the demand at times in Germany). The French premium over the German forward contract also reflects worries over the availability of the French nuclear fleet. The premium of the French contract over their German equivalent contract peaked at 142 €/MWh in the third week of October and it reached a low of 28 €/MWh at the end of Q4 2022.

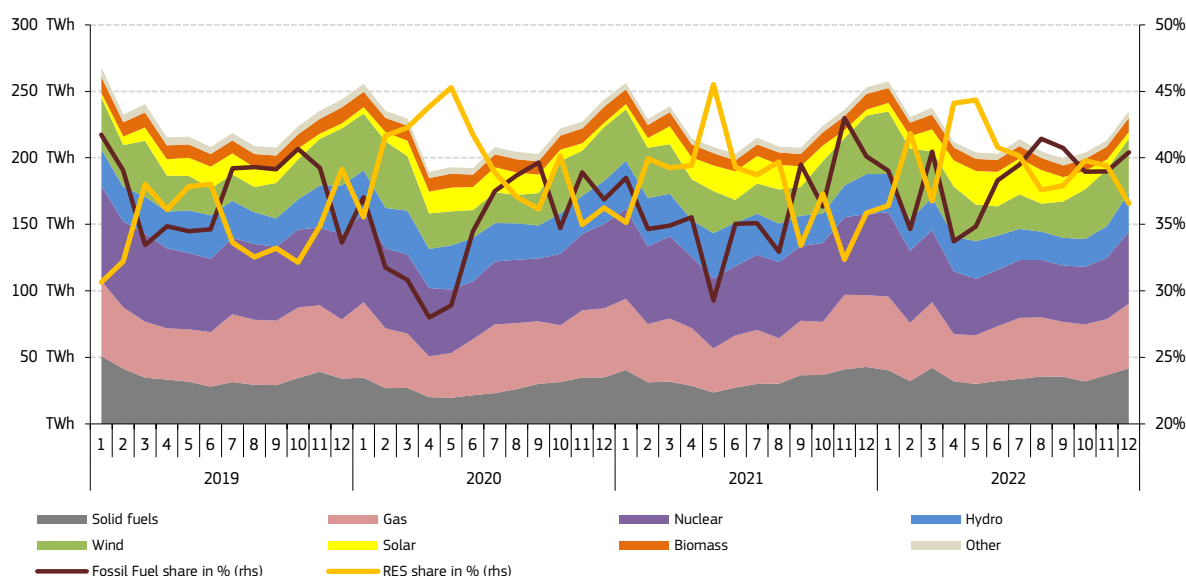
Figure 18 – Weekly German and French year-ahead contracts



Source: S&P Global Platts.

- **Figure 19** shows the monthly evolution of the electricity mix in the EU. In Q4 2022, reduced electricity demand, relevant increase in solar generation and high prices, supported the decrease in fossil fuels generation in the mix. Renewables managed to increase their share to 39% (from 35% in Q4 2021). The share of electricity generated by burning coal, gas and oil (fossil fuel generation) fell slightly to 39% in Q4 2022 (from 40% in Q4 2021). Nuclear generation remained another quarter under pressure, due to unplanned outages and delayed scheduled maintenance in France, decreasing its share of generation in Q4 2022 to 22% (from 25% in Q4 2021). Nuclear output fell by 19% (-34 TWh) in Q4 2022.
- Within the fossil fuels realm, coal-fired plants (hard coal and lignite) generated 10 TWh less (-8%) in Q4 2022, compared with Q4 2021. Despite efforts of some Member States to delay the phase out coal-fired plants, it did not translate in more generation hours for this type of fossil fuel technology in Q4 2022. This is the first quarter a decrease in coal generation is recorded since Q4 2020. Overall, fossil fuel generation registered a decrease of 27 TWh y-o-y (-10%). Coal's (hard coal and lignite) share in the mix remained at 17%, whereas less CO₂-intensive gas generation fell slightly to 20% in the reference quarter (from 21% in Q4 2021). In absolute terms, hard coal-based generation fell by 6.5 TWh year-on-year (-11%) and lignite output fell by 4=3.6 TWh (-6%). Gas-fired power plants' output fell by 17 TWh (-11%). Hard coal generation fell by 12% in Germany, 31% in the Netherlands, 23% in Spain and 5% in Poland in Q4 2022.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 19**), lignite generation traditionally displays more competitive marginal costs per unit of energy produced even facing the current high 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 12% more expensive in Q4 2022 compared with Q4 2021. Lower demand combined with lower gas prices contributed to a decrease on lignite-based generation in Q4 2022.

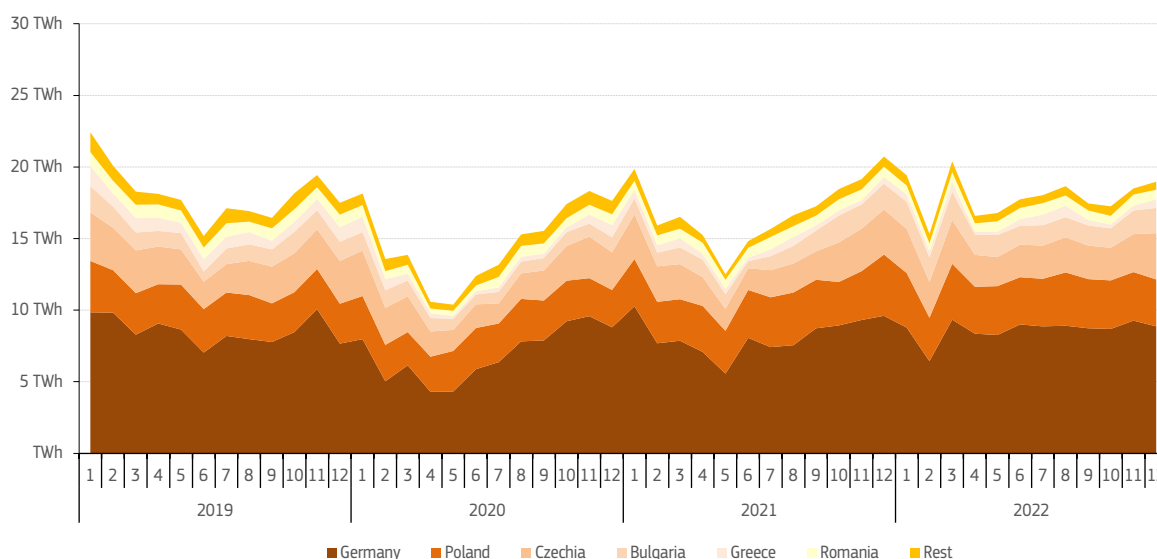
Figure 19 – Monthly electricity generation mix in the EU



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

- **Figure 20** shows a potential end of the comeback of lignite generation, after quarters marked by soaring gas and hard-coal prices, which impacted on the competitive edge of gas- and hard coal-fired power plants in the context of the energy crisis. Unlike previous quarters, practically all Member States with remaining lignite-fired capacity reduced its output during Q4 2022 on the impact of reduced power demand and relatively lower gas prices. Monthly output was at the lowest in October at roughly 17 TWh. In Germany, home to the largest lignite fleet, generation from the dirtiest fuel fell by 3% year-on-year in Q4 2022. Lignite-fired generation in Poland fell on year-on-year by 13% in Q4 2022. The output of the Czech lignite fleet decreased by 11% year-on-year. The three Member States accounted for 82% of the total lignite-based generation in the EU in Q4 2022. In Greece, lignite generation fell by 6% year-on-year while in Bulgaria, lignite generation fell by 12% compared to Q4 2021. Lignite power plants reached an 8% share in the EU generation mix in Q4 2022 (at the same level as in Q4 2021) and were responsible for approximately 32% of the electricity sector's total carbon emissions in the reference quarter.

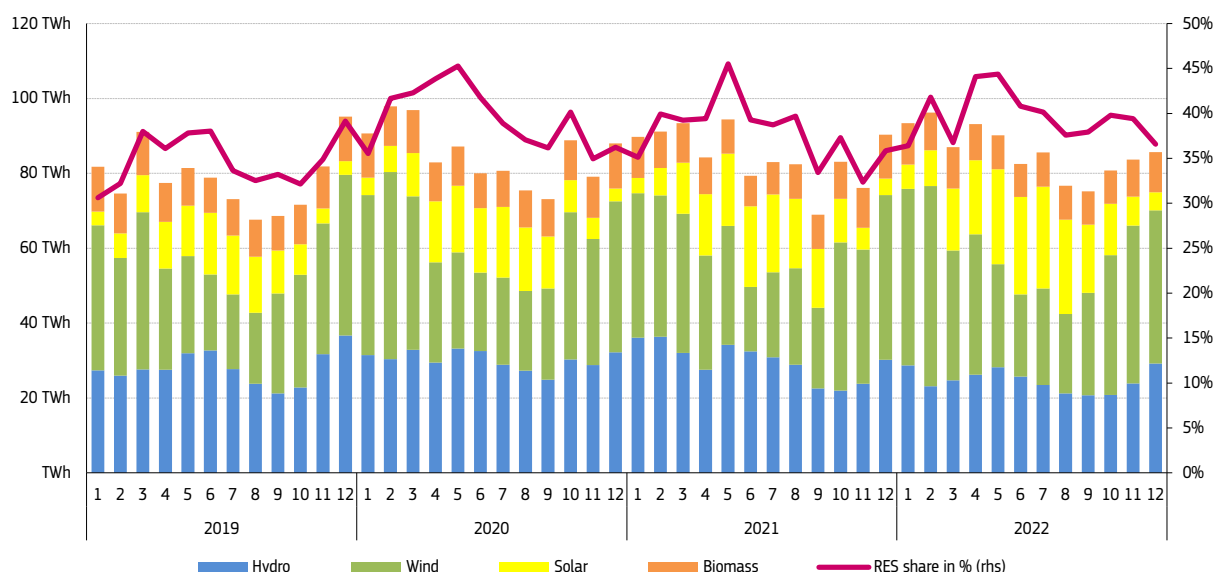
Figure 20 – Monthly generation of lignite power plants in the EU



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

- **Figure 21** depicts the evolution of monthly renewable generation in the EU, alongside its share in the electricity generation mix. The share of renewables reached 39% in Q4 2022, higher than the 35% share of Q4 2021. The growth in renewable penetration during Q4 2022 was supported by improved solar and wind generation, despite low levels of hydro and biomass output. Wind and solar generation together were higher than gas-fired generation during 2022.
- The main gains in renewable output came from solar (+4 TWh), wind onshore (+1 TWh) and wind offshore (+0.3 TWh) in comparison with Q4 2021. Thanks to increasing installed capacity, solar PV generation rose by 20% in Q4 2022 to a total of 26 TWh. In absolute terms, the increase was mostly driven by +1 TWh in Germany (+5%), +0.7 TWh in the Netherlands (+21%) and +0.5 TWh in Poland (+90%). For another quarter, Poland registered impressive solar output figures thanks to a large deployment of new solar PV capacity in the country (close to 5 GW in 2022).
- Thanks to the rapid development of new capacity, onshore wind gains during the reference quarter (+1%) were reported mainly by almost +2 TWh in France (+18%), followed by +0.8 TWh in the Netherlands (+6%) and by +0.5 TWh Finland (+19%). At 12 GWh, the French wind onshore generation in Q4 2022, was two times higher than in the previous quarter of the year (Q3 2022). Wind offshore registered an increase in its output (close to +2%). The increase in absolute terms was mostly driven by the Netherlands (+0.2 TWh). Overall, wind output remained with a surplus (+1 TWh) in Q4 2022, increasing its generation by 1% year-on-year.
- Despite improvements in hydropower generation during Q4 2022, hydro output fell by 3% (-2 TWh). Main hydro generation volume losses were registered in Italy (-2.5 TWh), Finland (-1.2 TWh) and France (-0.6 TWh) as a result of low stock levels and limited precipitations. Conversely, Portugal (+1.2 GWh), Spain and Germany (+0.4 GWh) registered additional hydro generation in Q4 2021. Biomass losses (-9%) during Q4 2022 were reported mainly by -0.5 TWh in the Netherlands (-22%).

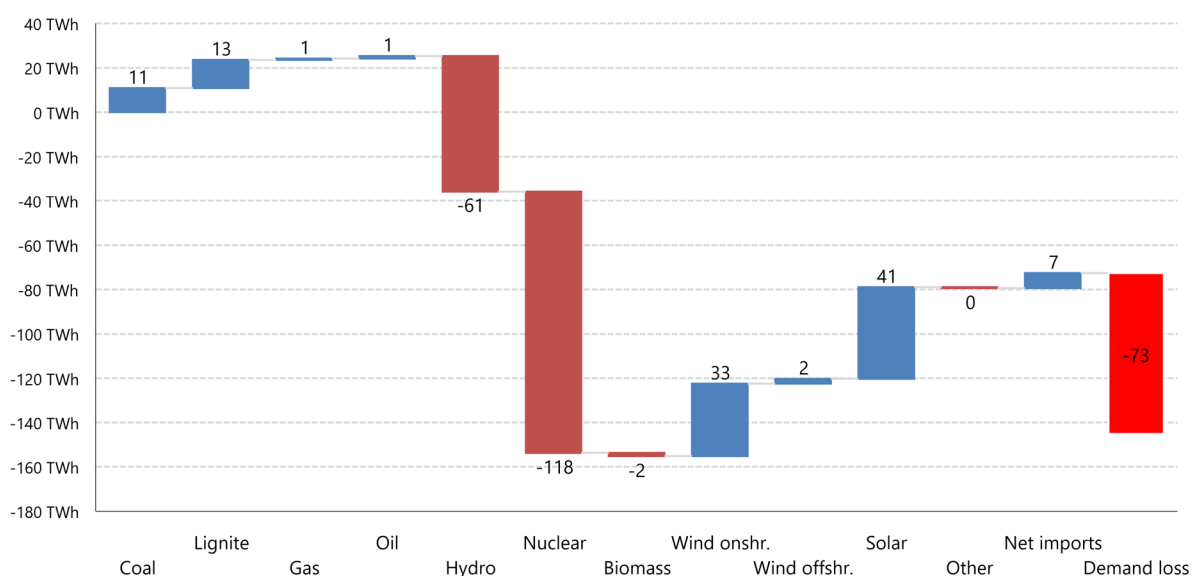
Figure 21 – Monthly renewable generation in the EU and the share of renewables in the power mix



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

- Figure 22** visualises changes in the EU27 electricity generation, imports and consumption in 2022 compared to 2021. The unprecedented rise in energy commodity prices (mainly gas) due to the Russian war in Ukraine, impacted on power prices, causing demand destruction on both at household and industrial levels. In addition, mild weather during winter supported a reduction in power demand by 73 TWh. Fossil fuels boosted their generation by +24 TWh. Renewable sources generation (including hydro) also rose 14 TWh (+1%). Remarkably, the combined generation of wind and solar energy sources yielded a notable increase of 14% (+76 TWh), reflecting the level of development of new capacity for these technologies. Net imports increased (+7 TWh) compared with 2021. Conversely, nuclear generation plunged considerably (-118 TWh), mainly on issues linked to outages and maintenance in the French nuclear fleet, while hydropower generation fell considerably (-61 TWh) on the impact of a drought that affected Europe. All in all, hard coal increased its output by 11 TWh, lignite by 13 TWh, whereas gas increased by less than 1 TWh as a result of high prices. Oil generation increased slightly compared with the levels of 2021 (+1 TWh). Based on preliminary estimates, the carbon footprint of the power sector in the EU rose close to 4% year-on-year in 2022, due to a larger use of fossil fuels. However, emissions were still 3% lower than in 2019. It is interesting to note that the +76 TWh of wind and solar generation combined, were able to cover more than 40% of the gap left by the decrease of hydro and nuclear altogether (-179 TWh). The notable surge in solar PV and wind power generation would have resulted in a noteworthy reduction in emissions if it had not been for the gap left by the lack of nuclear and hydro output in the system. Nonetheless, without this increase in wind and solar, the rise in emissions would have been even more severe in 2022.

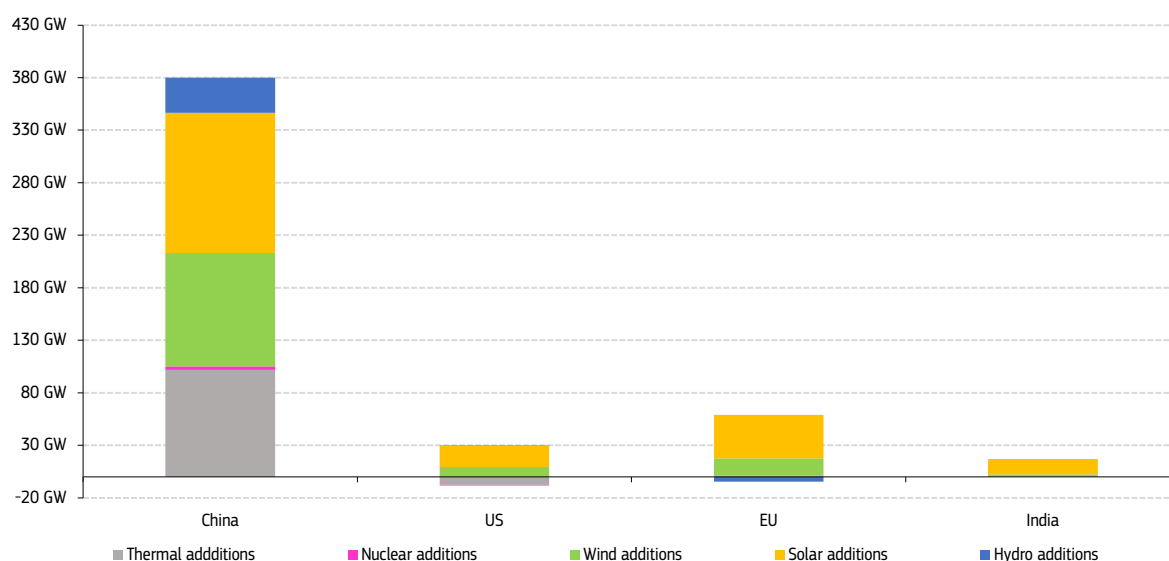
Figure 22 – Changes in power generation in the EU between 2021 and 2022



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

- Figure 23** maps newly installed power capacities on a net basis in the EU in 2022 and, for the sake of comparison, in other major economies. Rising carbon-free generation in the EU was greatly helped by a record addition of 57 GW of renewable capacity (16 GW of wind and 41 GW of solar PV), which was 47% higher than the added capacity in 2021 and increase of 16% of total installed renewable capacity in 2021). The deployment of renewables will need to triple by the end of the decade to reach ambitious energy and climate targets. High inflation, high commodity prices and supply chain issues could impact the required development of RES capacity. REPowerEU is already helping to simplify permitting rules for renewables installation. The Net-Zero Industry Act will create better conditions to set up net-zero projects in Europe and attract investments. Moreover, the proposed reform of the EU electricity market design seeks to incentivise investments in renewables by facilitating access to longer-term contracts for developers (both State-supported Contracts for Difference, and private Power Purchase Agreements).
- The largest increases in the renewable capacity were registered in Spain (+10.8 GW), where solar PV was the main driver and Germany (+10.6 GW), where both solar and wind sectors contributed to the result. Poland (+7.9 GW) and France (+6.8 GW) also saw significant renewable capacity additions, followed by the Netherlands (+6.6 GW) and Sweden (+6 GW). Greece (+1.9 GW) was also among Member States making notable progress. The scheduled shutdown in 2022 of the remaining three nuclear reactors in Germany (Isar-2, Neckarwestheim-2, Emsland) was delayed by mid-April 2023, to ensure security of supply during winter. The phase out will remove 4.3 GW of nuclear capacity from the grid. Roughly 1.5 GW of thermal capacity was added on a net basis. This includes almost 5 GW of gas-fired power plants added during 2022 and roughly a net value of 3 GW of coal-fired power plants decommissioned in the EU during 2022.
- Outside Europe, for another year the largest renewable additions were registered in China (133 GW of solar, 108 GW of wind and 34 GW of hydro) which also put 102 GW of additional thermal capacities online in 2022. The US witnessed 8 GW of thermal retirements and 30 GW of additions in the renewable segment.

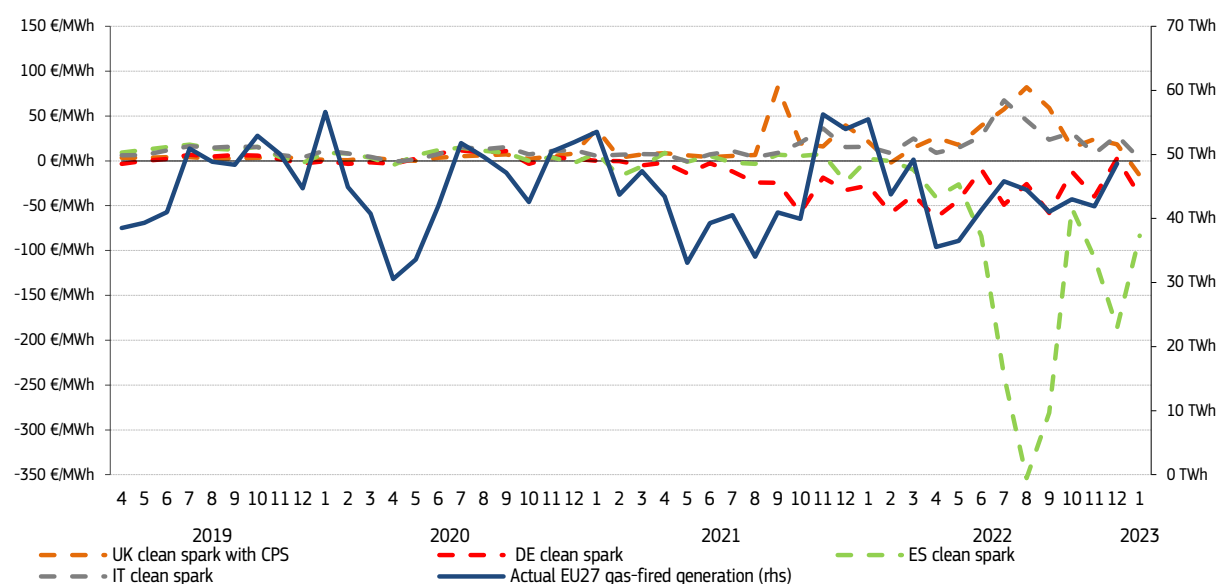
Figure 23 – Net capacity additions across major economies in 2022



Source: China Electricity Council, Central Electricity Authority of India, EIA. For the EU, ENTSO-E figures were used for thermal, nuclear and hydro additions; latest estimates from WindEurope and SolarPower Europe for wind and solar additions.

- 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. Throughout 2022, high gas prices turned gas-fired into unprofitable levels. However, lower gas prices in Q4 2022, improved the levels of profitability of gas plants, which continued well into Q1 2023. Coal-fired plants, despite high coal prices, were able to improve their position in the profitability zone vis-à-vis gas-fired plants. The Italian, German and UK [clean dark spreads](#) remained on average at positive levels during 2022. However, despite higher levels of profitability of coal-fired generation, the fuel switching capacity is limited by the scarcity of coal-fired plants still in operation due to the decommissioning of the fleet over the last years, despite efforts of some MS to bring back some extra capacity to the market. Likewise, despite high gas prices, [clean spark spreads](#) remained at positive levels in the case of UK and Italy in 2022.
- As shown in **Figure 24**, the profitability of gas firing for electricity generation remained in the UK and Italy in the positive territory for a plant with an average efficiency during Q4 2022. The positive profitability levels of gas-fired generation in Italy are likely due to higher wholesale electricity prices and higher number of hours when gas is the marginal technology, setting the electricity generation costs and wholesale market prices. In Germany, the profitability of gas-fired generation remained in the negative zone for most of 2022, due to high gas prices outpacing the rise in wholesale electricity prices. However, German clean spark spreads returned to positive territory in December 2022, for the first time since January 2021. Conversely, the Spanish equivalent continued in the negative territory during the quarter. The abrupt fall in profitability compared with previous years might be related to the impact of the ['Iberian exception'](#), that subsidises gas-fired generation. The highest clean spark spreads in Q4 2022 were assessed in Italy (23 €/MWh), followed by the UK (19 €/MWh). Germany averaged at -44 €/MWh in Q4 2022. The lowest was registered by far in Spain (-116 €/MWh), recording a low of -186 €/MWh in September. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets (with the notorious exception of Spain). The total EU gas generation reached 133 TWh in the reference quarter, down by 11% compared to Q4 2021.

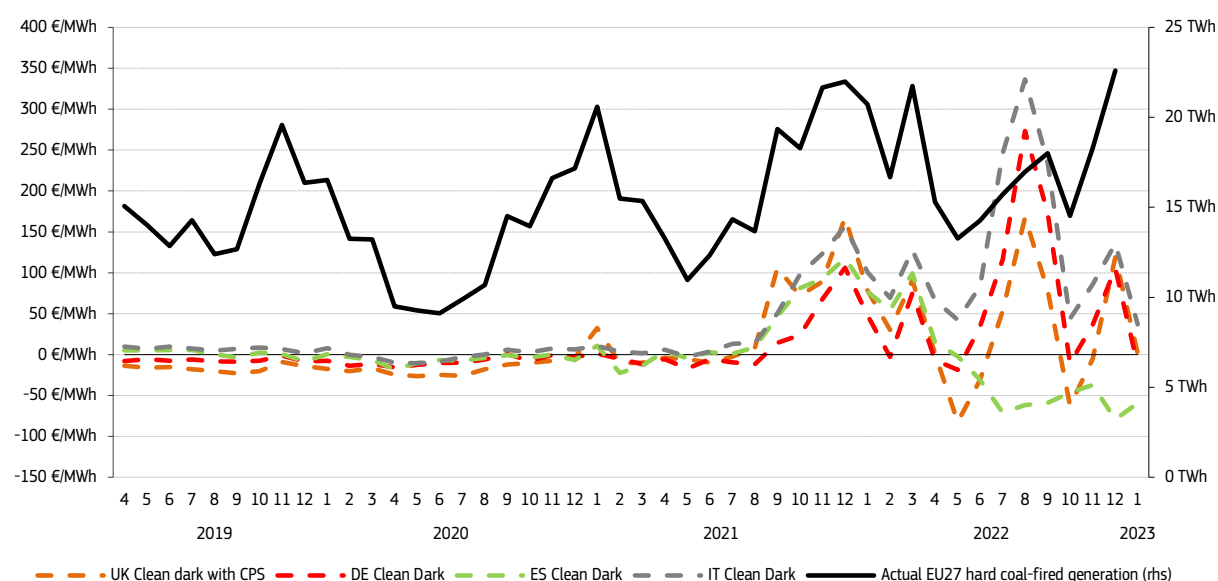
Figure 24 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 25** shows that Italy, followed by Germany, experienced the most profitable coal-fired power generation in Q4 2022. In December, most of the selected markets recorded peaks in the profitability indicator for an average plant. This was primarily due to the high gas prices, even though coal prices remained high as well. [Clean dark spreads](#) in Italy averaged 89 €/MWh in Q4 2022, almost four times than in the case of gas-fired power plants. For another consecutive quarter, Spain was the only selected market registering negative profitability of coal-fired plants. This is likely the case as a side effect of the 'Iberian exception', subsidising not only gas, but also coal for power generation. Despite positive levels of profitability, German hard coal generators decreased their output by 12% year-on-year in Q4 2022, as lower demand (-9% year-on-year in Q4 2022), supported by increased renewable generation decreased the need for further thermal generation. Despite the return of coal capacity to the market, coal-fired generation did not increase in Q4 2022.

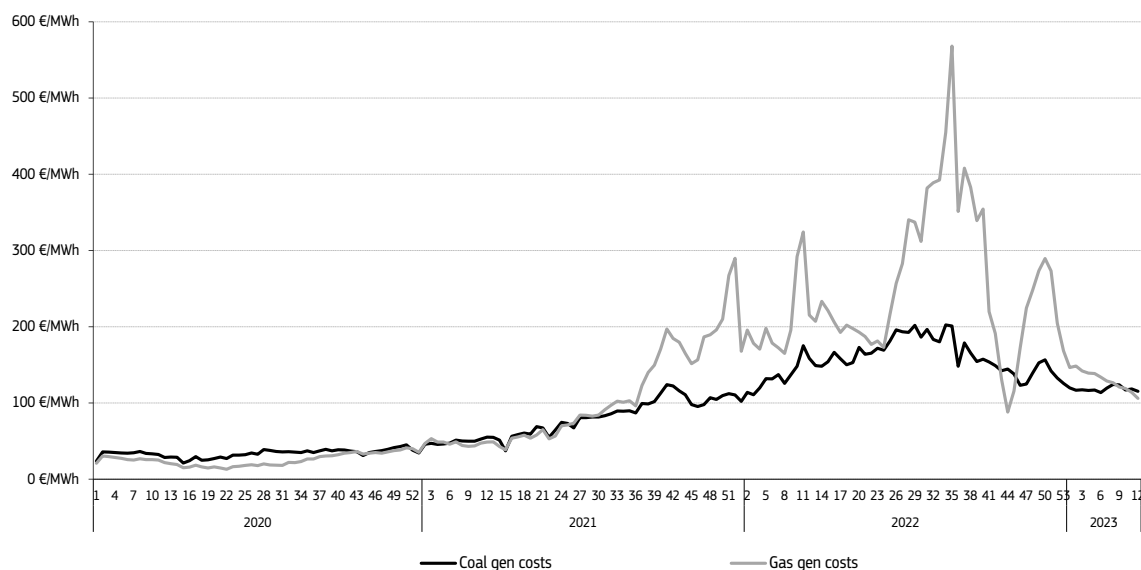
Figure 25 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU



Source: ENTSO-E, Eurostat, Bloomberg

- Figure 26** shows the impact of gas prices on estimated gas and coal-fired generation variable costs for estimated average power plants (fuel and emission allowances). 2022 was marked by unprecedented gas prices which impacted heavily on gas-fired generation costs, offsetting the effect of the increase in coal and carbon prices on coal-fired generation costs. However, during the final weeks of October, the first week of November, and the second half of December, gas prices experienced a decline while coal prices remained relatively high. This created favourable conditions for a shift from coal to gas, after nearly one year and half of uneconomical conditions for coal-to-gas fuel switch. The trend continued well into Q1 2023, with high levels of gas storage, falling gas prices together with high carbon prices. These factors, supported by reduced demand and increase levels in renewables output are creating favourable economic conditions for gas-fired generation. However, potential hydropower and nuclear recovery in 2023 could reduce even further the thermal generation gap, reducing the influence of fuel-switching economics in the dynamics of thermal generation.

Figure 26 – Variable generation costs of coal- and gas-fired power plants

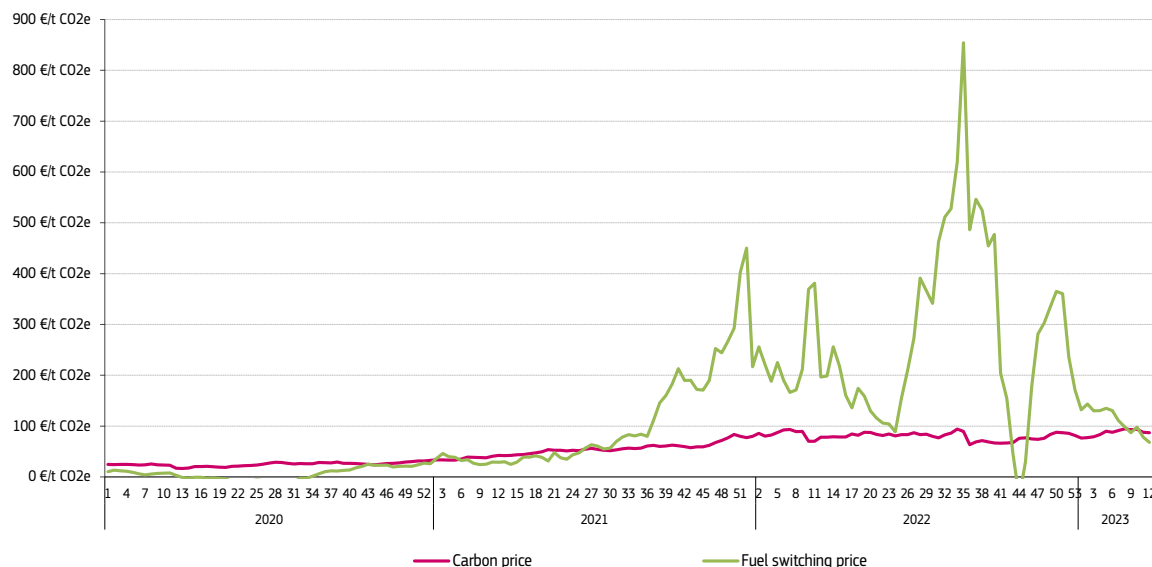


Source: S&P Platts, ENER.

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 27** shows how the reduced gas prices during October and then from the second half of December, combined with high carbon and coal prices, improved the economics of gas-fired generation vis-à-vis coal-fired power plants. The estimated average fuel switching price required to make gas-fired plants economically viable vis-à-vis coal fell below EU ETS prices (roughly at 70 €/tCO₂) during the last weeks of October and the first week of November. The trend was briefly interrupted in November to early December, where fuel switching price stood on average at 365 €/tCO₂ on bouncing back gas prices. However, lower gas prices from the second half of December onwards, combined with high carbon prices, supported a new fall in the fuel switching price to 68 €/tCO₂ in the third week of March 2023. Average carbon prices stood at 87 €/tCO₂, while TTF spot gas prices were at 41 €/MWh during that week.

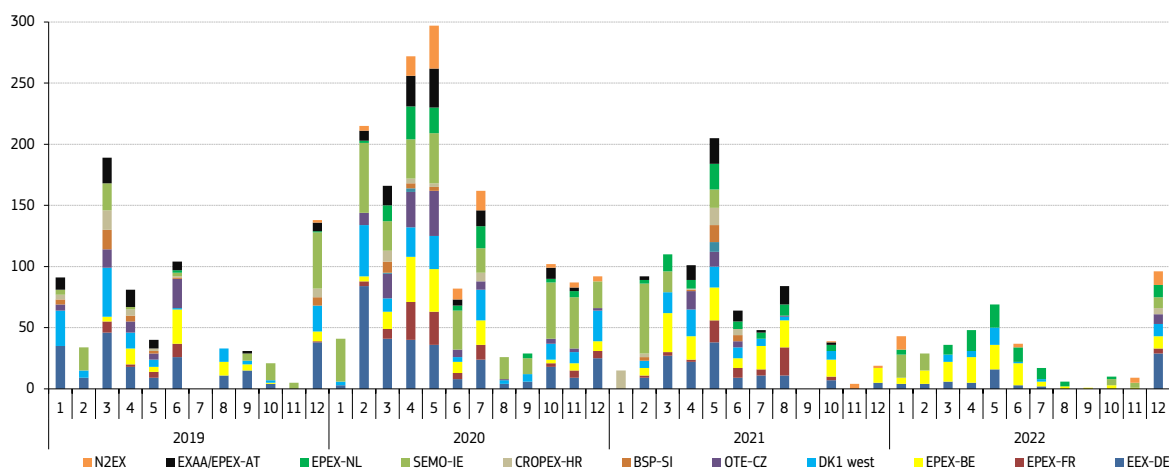
Figure 27 – Coal-to-gas fuel switching



Source: S&P Global Platts, ENER.

- **Figure 28** 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 Q4 2022 (272) was 157% higher in the observed bidding zones than in the previous fourth quarter. Most of the falls into negative territory occurred in December (112) and took place in days when low consumption coincided with high renewable generation. Demand reduction in December may also have influenced the occurrence of negative prices. Negative prices in December represented 41% of negative prices observed in Q4 2022, and 20% of negative prices in 2022. The highest number of negative prices (59) was recorded on 31 December, when weak demand and mild weather, combined with strong wind speed, pushed Germany and some Nordic (Sweden, Finland and Denmark) Baltic (Estonia, Lithuania and Latvia) and CEE markets (Czechia and Slovakia) below zero during several hours of the day. Notably, 22 hours of that day registered negative prices in Germany. Wind generation covered a considerable share (70%) of the German consumption during that day.
- 2022 negative prices reached to pre-pandemic levels (2017-2019), which numbered at 555 in the bidding zones under observation, a decrease of 42% compared with 2021 and 70% with the exceptional year of 2020.
- The Belgium zone recorded the highest number of negative hourly prices (112) in 2022, followed by the Netherlands (85), Germany (69), the integrated Irish zone (51) and Danish west (DK1) zone (38). The Belgium zone recorded a decrease of 30% in the occurrence of negative hourly prices in 2022 compared with 2021, while the Netherlands registered an increase of 21% in the same period. High energy commodity prices supported the decrease of the occurrence of negative prices on wholesale electricity markets in 2022. However, as Europe potentially starts to move away from unprecedented energy prices in 2023, the higher level of penetration of variable renewables will accentuate the new challenges to the grid balance and the need for more flexibility in the European power system.

Figure 28 – Number of negative hourly wholesale prices on selected day-ahead trading platforms

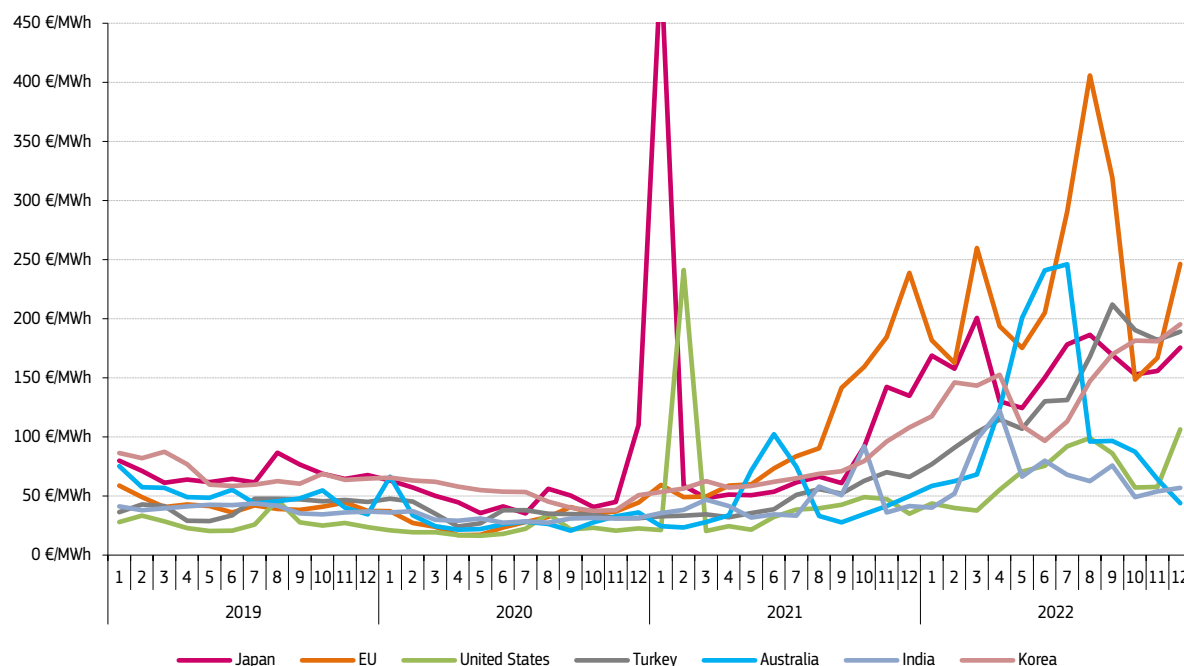


Source: Platts, ENTSO-E. For Austria, the EXAA market is used prior to October 2018, and the EPEX market is used afterwards.

- Figure 29** 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 effect of the Russian war in Ukraine and associated sanctions. In the U.S., wholesale electricity prices increased in most of the analysed regional wholesale markets, with California leading the surge in prices in Q4 2022, due to colder-than-average weather, lower supply of gas due to decreased gas volumes from a Texas pipeline, combined with dry weather. Higher demand in December, due to cold weather and a snowstorm at the end of the month, supported an increase in prices at the end of Q4 2022. Overall, the U.S. price benchmark increased by 68% in Q4 2022 compared with Q4 2021. In the beginning of 2023, wholesale electricity prices decreased in many U.S. markets due a fall in Henry Hub prices and milder weather. However, California's wholesale electricity prices remained relatively high compared to other markets. The April 2023 edition of the EIA's [Short Term Energy Outlook \(STEO\)](#) expects lower electricity demand, renewable energy growth, and lower natural gas prices (Henry Hub price should decrease by more than 50% in 2023) for Q2 and Q3 2023, which should lead to decreased power prices compared to the same periods in 2022.
- In Japan, a rise in winter demand contributed to high wholesale electricity prices during Q4 2022 (+31%). In December, snowstorms hit the northern part of the country increasing demand. Japan relies heavily on fossil-fuel power generation, and it is one of the most important LNG buyers in the global market. The Japan-Korea Marker (JKM), LNG benchmark and TTF prices were trading closely during the first months of 2023, following a decreasing trend. South Korea was equally also to increased winter demand, driving prices 97% higher in the reference quarter.
- European wholesale prices were once again, the highest of the observed economies in Q4 2022, reaching 187 €/MWh. In Australia, wholesale electricity prices registered an equivalent of 65 €/MWh (+55% year-on-year) in Q4 2022. Despite the yearly increase, prices have eased from unprecedented levels seen early in 2022. The price differential has increased between northern and southern regions of the National Electricity Market (NEM). Evening and overnight energy prices increased in both northern and southern regions of the NEM due to higher input costs and coal-fired generation offers moving to higher price bands. Conversely, daytime prices remained low due to increased solar and wind generation and lower demand, with significant incidence of negative prices in the southern mainland regions². In December, the Federal Government announced an intervention in the wholesale domestic gas and coal markets via a temporary price cap, easing prices during that month. Prices in India fell by 6% in Q4 2022.
- For the whole year of 2022, wholesale prices in the EU averaged 230 €/MWh, well above other economies such as Japan (163 €/MWh), Korea (146 €/MWh), Turkey (141 €/MWh), Australia (116 €/MWh), the U.S. and India (69 €/MWh). European prices were 235% higher than in the US.

² Australian Energy Market Operator (AEMO) Quarterly Energy Dynamics Q4 2022

Figure 29 – Monthly average wholesale electricity prices in international markets (D-A markets)

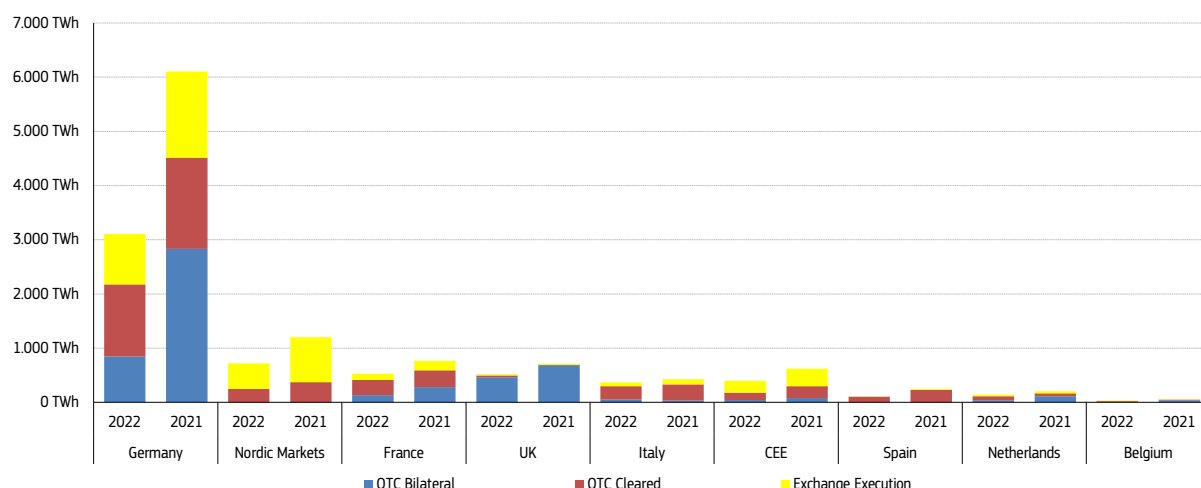


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (the latest data for Russia is not available), Energy Exchange Istanbul (Turkey) and the average of selected PJM West, ERCOT, MISO Illinois and CAISO regional wholesale hubs in the United States. BloombergNEF (India and Korea).

2.2 Traded volumes and cross border flows

- Figure 30** shows annual changes of traded volumes of electricity in the main European markets, including exchange-executed trade and over-the-counter (OTC) trade. For another consecutive quarter, most markets and regions witnessed a year-on-year decline in trading activity in 2022 (-43%). The decrease in total traded volumes (-4416 TWh) reflects the magnitude of the falling trend in trading activity in the electricity sector. The unprecedented electricity prices and increased volatility in the energy markets contributed to the drop in liquidity. Activity dropped significantly in OTC contracts (-44%) and exchanges (-40%) in the total traded volumes under observation during 2022.
- The largest annual falls in total traded volumes were registered in Spain (-56%), Germany (-49%) and Belgium (-43%). 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 43% to 5928 TWh in 2022.
- Despite falls in traded volume, Germany was by far the largest and most liquid European market, as total volumes reached 3108 TWh (equivalent to 52% of the total traded volumes under observation in 2022). Overall, total activity fell (-49%) in Germany in 2022. In Germany, the market share of exchanges experienced an increase (+4 p.p.) while the OTC contracts share decreased compared with 2021. Spain and Belgium markets registered a fall in activity of 56% and 43%, to 102 TWh and 35 TWh, respectively. Relative decreases in activity were also visible in the Nordic markets where total volumes fell (-40%) to 719 TWh. Moreover, relative decreases were also visible in the CEE market where total volumes fell by 36% to 397 TWh.
- Overall, the market share of power exchanges expanded from 30% to 32% in 2022. The only increase in exchange-based volumes of the reported markets were registered in the UK (+14%), while the largest falls were registered in Spain (-76%) and the Nordic markets (-43%). Overall, exchange-based trading volumes decreased by 1223 TWh in 2022 (-40%). The OTC segment traded 3193 TWh less of electricity 2022 compared with 2021, as a result of lower volumes changing hands in Germany, Spain and Belgium. OTC volumes reduced their share of the market to 68% in 2022, from 70% in 2021. Spain, Germany, the Netherlands and Belgium registered the largest decrease in bilateral OTC deals (-83%, -70%, -66% and -63% respectively).

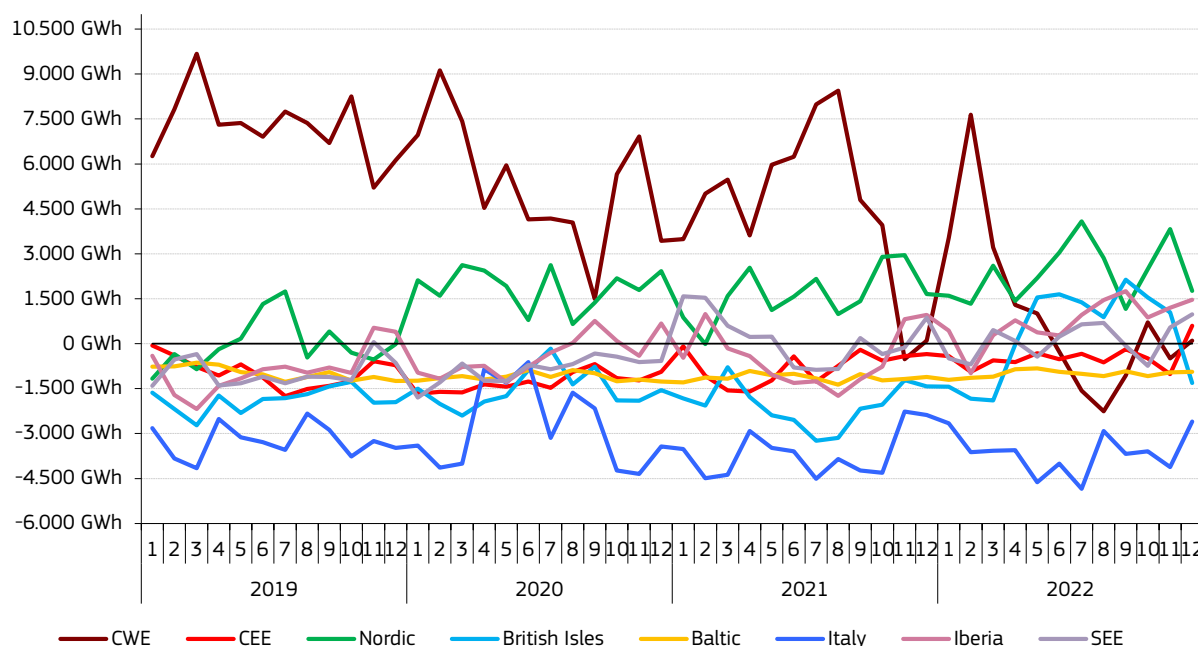
Figure 30 – Annual change in traded volume of electricity on the most liquid European markets



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

- Figure 31** 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 Q4 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, despite improving its position with regards the previous quarter, CWE registered 0.3 TWh of net exports in Q4 2022. The drop can be attributed mainly to the lower availability of nuclear power due to maintenance or due to safety protocols, even though there was an increase in availability compared to the previous quarter. This, along with lower hydropower generation and high gas prices in the main markets of CWE, resulted in a decline in export availability. Conversely, for another consecutive quarter, net flows in the British Isles changed their traditional direction (net imports) compared to Q4 2021. In Q4 2022, the British Isles recorded 1.3 TWh in net exports. The Nordic region recorded a surplus of 8 TWh in the reference quarter, 8% higher than net exports in Q4 2021. The Iberian Peninsula recorded 3.5 TWh of net exports in Q4 2022, compared with 1 TWh of net imports in Q4 2021. The trend has been supported by the subdued nuclear generation in France and the impact on prices of the 'Iberian exception'. Likewise, SEE registered 0.7 TWh of net exports, increasing its exports in comparison with Q4 2021.
- The rest of the regions ended up in deficit, mainly due to less available generation across the EU in general. Reduced nuclear availability, hydro output and high gas prices supported this situation. Italian net imports increased by 15% year-on-year to -10 TWh in Q4 2022. The CEE region's net position (-1 TWh) improved by 31% in Q4 2022 compared to Q4 2021.

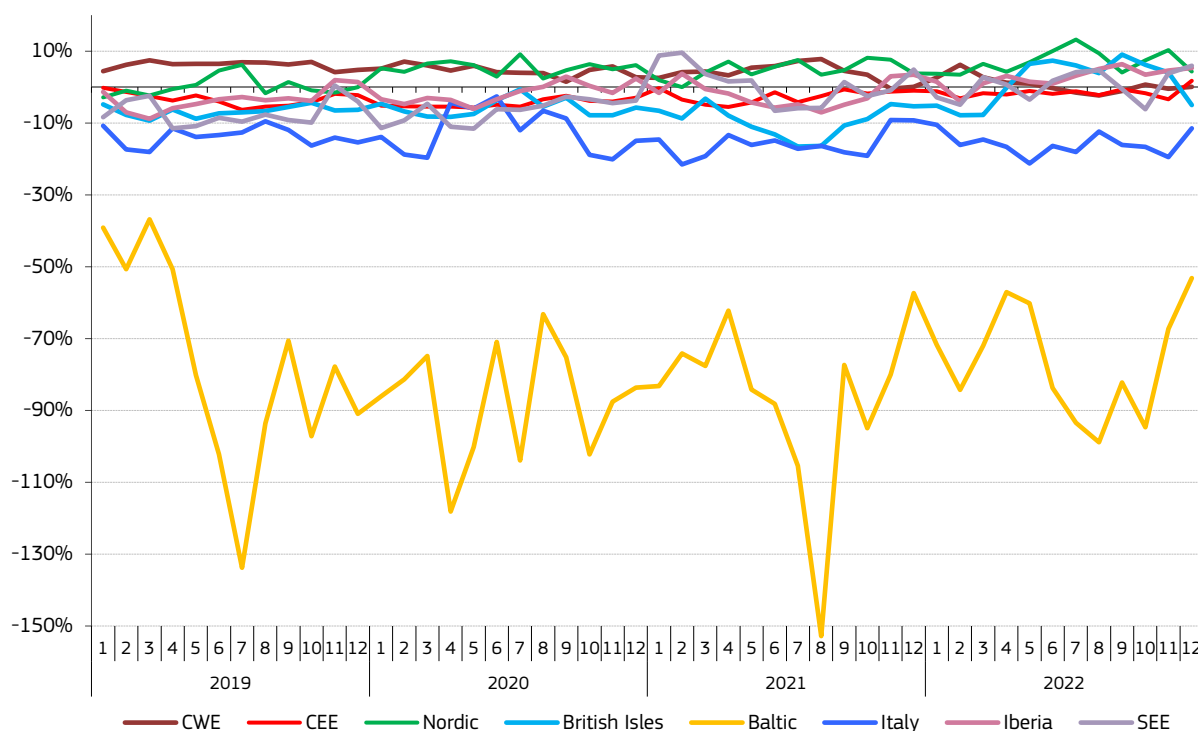
Figure 31 – European cross-border monthly physical flows by region



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), British Isles (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 32** 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 in the negative territory in Q4 2022. Net imports (3 TWh) reached about 72% of domestic generation, which is still an improvement of 20 p.p. compared with Q4 2021. Italy became the second largest importer relative to its domestic generation (16%). For the rest of the regions, net imports (or exports) did not exceed 8% of domestic generation.

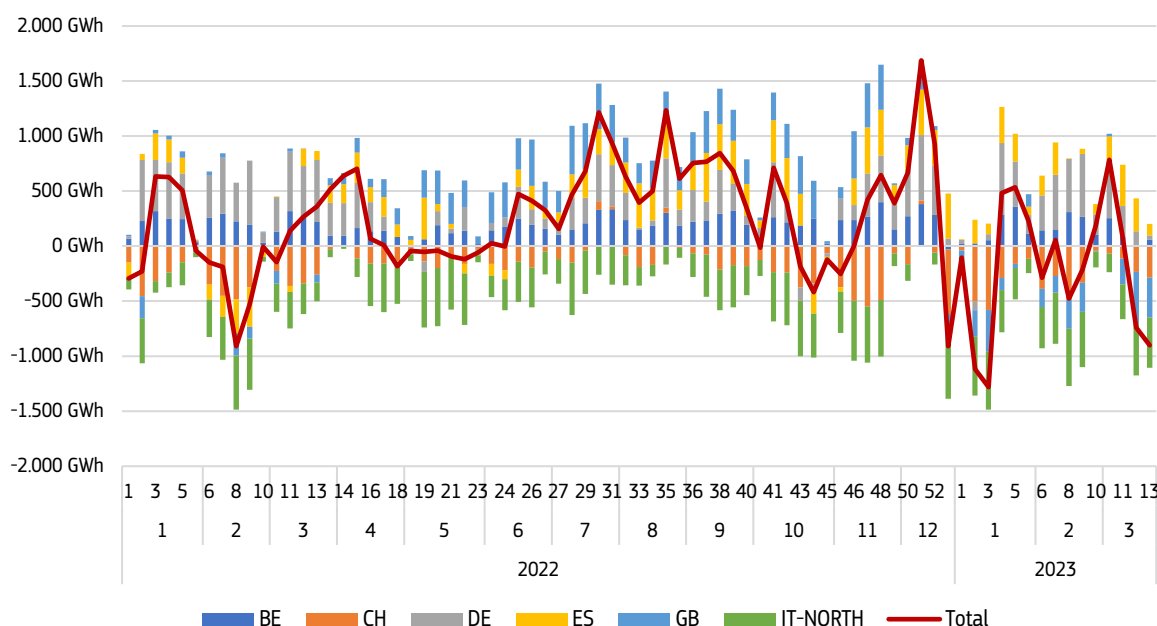
Figure 32 – The ratio of the net electricity exporter position and the domestic generation in European regions



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

- **Figure 33** compares France's net cross border scheduled flows from neighbour markets during in 2022 and first weeks of 2023. Positive values indicate flows going into France (net imports). The low availability of the French nuclear fleet caused a reversal of traditional position of France as net exporter in the region. In 2022, France imported electricity from all neighbouring bidding zones, except from the North of Italy. Net imports of France in 2022 recorded 16 TWh, a staggering difference compared with the net exports registered during 2021 (-43 TWh). During the first thirteen weeks of 2023, the situation improved as the availability of nuclear fleet increased. As a result, France became a net exporter during this period, with 2.7 TWh of net exports. However, this was still lower than the equivalent period in 2021, which were 7.8 TWh of net exports. Nevertheless, it was still an improvement compared to the same period in 2022, when France had only 40 GWh of net imports.

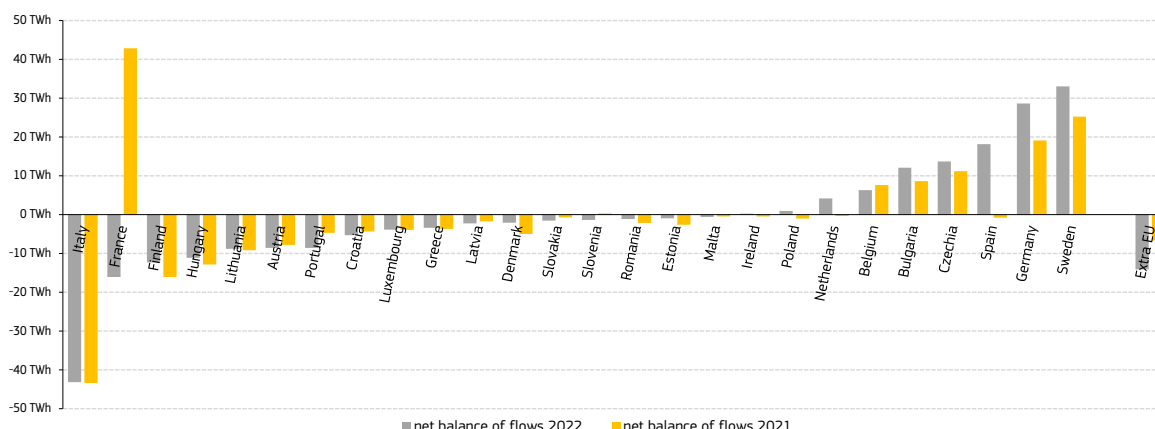
Figure 33 – French cross-border weekly scheduled flows



Source: ENTSO-E

- **Figure 34** compares net balances of physical electricity flows among EU Member States in 2022 and 2021. The energy crisis fuelled by tightness in the global energy commodity markets and by the disruption in markets caused by the Russian war in Ukraine, supported by a decline in nuclear availability and a drought that impacted hydropower output throughout the regions of the EU. As a result, the net trading position was less balanced than previous years.
- Unlike other years, France, historically the largest exporter of electricity in the EU, saw its net flows fall by 59 TWh in 2022, compared with 2021 (16 TWh of net imports in 2022 versus 43 TWh of net exports in 2021). This was driven mainly by the lower availability of the French nuclear fleet throughout 2022. In 2022, Sweden became the primary net exporter for the EU, thanks to a discount in wholesale electricity prices due to nuclear and hydro generation vis-à-vis Finland, the Baltic countries and other continental Europe markets. Sweden's net exports amounted to 33 TWh, 31% higher than in 2021. The list was followed by Germany, as net exports rose to 29 TWh in 2022. Germany became the second net exporter in the EU due to a decrease in demand, an excess supply of wind, solar, and coal. The surplus of generation of these technologies was able to compensate for the gap left by the closed nuclear power plants in 2021. As Germany will retire its three remaining nuclear reactors (1.3 GW Emsland, 1.4 GW Isar 2 and 1.3 GW Neckarwestheim 2) by mid-April 2023, the country is expected to potentially decrease its net exports in the short-term future. Spain ended 2022 as a net exporter, registering 18 TWh of net exports to other countries, a significant increase in comparison with the 1 TWh of net imports in 2021 (+19 TWh of flows changing direction). Spain was in the third place of net exporter countries in 2022. This was made possible by several factors, including the Iberian exception, which supported a discount in Spanish wholesale electricity prices vis à vis France. Thus, Spain increased its exports to France, which faced difficulties with its nuclear power plants, as gas-fired and renewable generation (mainly solar) increased in 2022. Czechia and Bulgaria saw their surpluses improve due to increasing domestic lignite output.
- Italy remained practically unchanged in its net deficit by at 43 TWh, as domestic generation remained at a similar extent to consumption. Finland, Hungary and Lithuania registered fewer net imports in 2022, as consumption fell more than domestic generation. The beginning of commercial generation of Olkiluoto 3 nuclear power plant in Finland (16 April 2023) will considerably improve Finland's its condition of net importer of electricity.

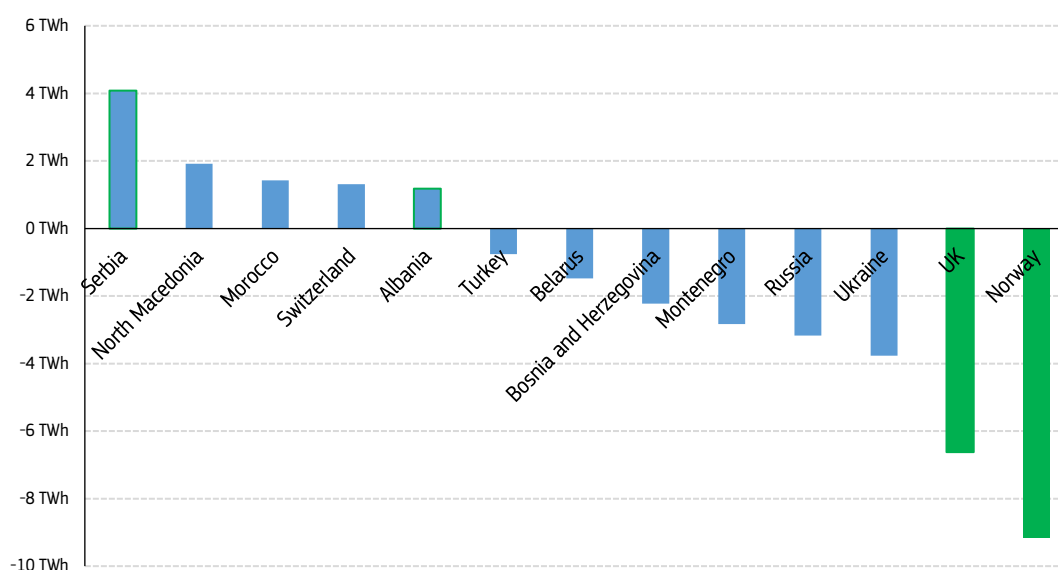
Figure 34 – Member States' net physical export/import positions within the EU in 2022 and 2021



Source: Physical Flows ENTSO-E, TSOs, Eurostat

- **Figure 35** shows netted electricity exchanges with EU neighbours in 2022. Unlike previous years, Great Britain became EU's second biggest import market with 7 TWh of net outflows from the island, a total of 31 TWh which changes direction in comparison with 2021 (UK registered net imports of 24 TWh). This was possible mainly due to the situation of the French nuclear fleet which increased flows from the UK to France, combined with lower demand in the UK and high levels of gas-fired generation.
- Norway retained its position as main net exporter to the EU, despite a decrease of 41% of net exports in 2022 (+9 TWh). Subdued hydro generation due to a drought, despite rising wind output, was responsible for the decline in exports as prices increased considerably in the southern bidding zones of the country, resulting in imports from Sweden, Denmark and particularly the UK. Russian net exports to the EU plunged by 70%, as from mid-May Russia no longer sold electricity with Finland and Baltic countries. Net imports of physical flows from Ukraine registered almost 4 TWh in 2022. Commercial exchanges of electricity between Continental Europe and Ukraine/Moldova started in June 2022, after the successful synchronisation of the power systems. Ukraine halted exports to Continental Europe after the massive Russian attacks of their energy infrastructure in October. Since then, the TSOs of Continental Europe have regularly increased the capacity available for trading. [ENTSO-E](#) has indicated that on 18 April 2023, the trade capacity has been increased to more than 1 GW.
- Exchanges with countries not applying similar level of carbon pricing resulted in net import of 6 TWh (a decrease of 73%). Serbia imported more from the EU than exported in 2022, while Bosnia and Herzegovina was a net exporter to the EU in 2022.

Figure 35 – Extra-EU electricity physical exchanges in 2022 – netted



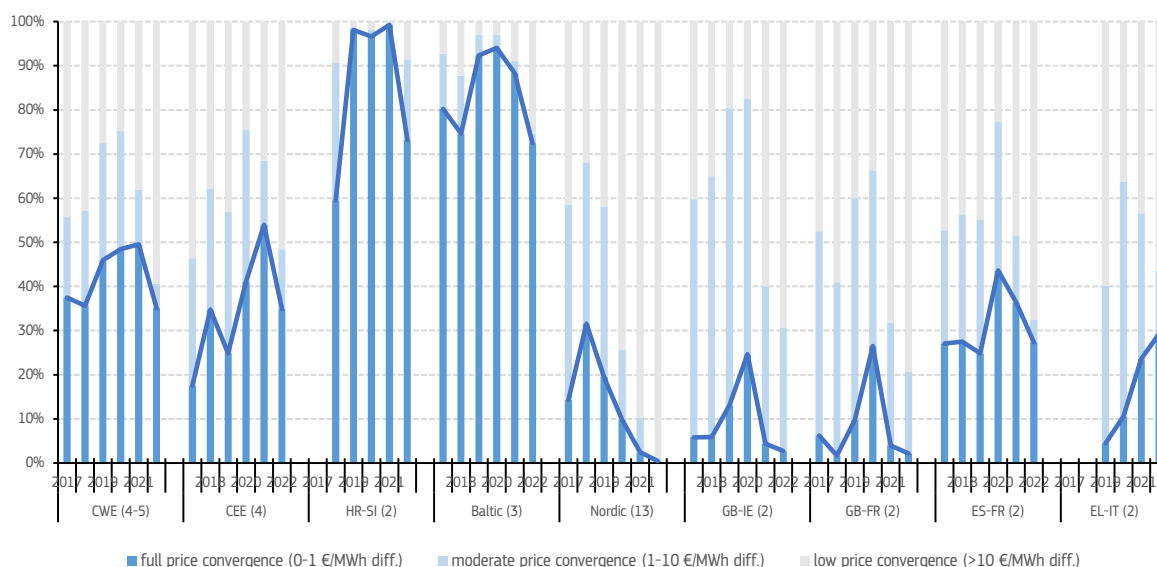
Source: Physical Flows ENTSO-E, TSOs, Eurostat. Negative values indicate net imports to the EU. Green colour denotes neighbours with similar or identical levels of carbon pricing.

3 Focus on developments in annual wholesale prices

3.1 Day-ahead price convergence

- **Figure 36** illustrates the degree of price convergence in day-ahead markets within selected European regions, expressed in percentages of hours in a given year. Price convergence provides an indication of the level of market integration. It is important to note that achieving complete price convergence (i.e. when the difference between hourly prices in all bidding zones is lower than 1 €/MWh) is not a goal in itself because it would demand investing excessively in network infrastructure. Longer-term drivers are market coupling initiatives or the expansion of inter-connection capacities. In the short term, fluctuations in convergence may also be caused by factors not necessarily related to the level of market integration, such as changes in the amount of cross-zonal capacity designated by TSOs for commercial purposes, long-lasting outages of transmission lines, significant shifts in the power mix or in consumption patterns. Several of these one-off factors influenced developments in convergence in 2022.
- Overall, market coupling supported day-ahead prices convergence throughout European markets, providing some relief from price spikes observed in 2022. However, the energy crisis emphasised certain structural disparities between markets, which resulted in significant declines in full price convergence. Despite this, the available transmission capacity acted as a buffer against more severe price spikes in the EU markets.
- In June 2022, the Core Flow-Based Market Coupling (Core FB MC) project announced its successful go-live. The aim of the Core FB MC to facilitate the development and implementation of a flow-based day-ahead market coupling across the entire Core capacity calculation region (Core CCR) within the Single Day-Ahead Coupling (SDAC) framework. As a part of the Core FB MC project, the market coupling between Croatia and Hungary was also implemented. The Flow-Based Market Coupling Mechanism is a significant development in the transition to sustainable energy. It improves the European power grid's capacity to handle fluctuations in variable renewable energy sources. Core comprises BE, CZ, DE, FR, HR, HU, LU, NL, RO, AT, PL, SK, SI with an estimated annual electricity utilisation of 1500 TWh.
- In the CWE region (the only region where flow-based market coupling has been applied since 2015) the number of occurrences of full price convergence decreased considerably (from 50% to 35% of hours). As mentioned earlier, the impact of the energy crisis, combined with the lower availability of the French nuclear fleet and subdued hydro generation, supported a divergence of prices between FR and its neighbours. In particular, Germany's renewable generation, combined with its remaining coal-fired fleet, were able to mitigate the spikes in prices in comparison with France.
- In Central Eastern Europe (CEE), full price convergence fell to 35% of hours (from 54% in 2021). The three Member States in the Baltic region remained highly convergent in 2022, although the full convergence of prices fell from 88% in 2021, to 72% in 2022. A rise in price divergence between the different Baltic bidding zones was accentuated by an increased difference in day-ahead prices between the EE and the LT-LV zones. Full price convergence fell slightly to 3% across the British Isles (from 4% in 2021). The two islands, linked by two interconnectors, were decoupled in 2021 which translated into an explicit system of trading where the British day-ahead order books were no longer coupled with other European markets. This halted the rise in convergence since the market coupling between Great Britain and the Irish Integrated Single Electricity Market in 2018. This situation has also contributed to cease the positive trend of rising convergence between Great Britain and France. The full price convergence between Great Britain and France fell from 27% in 2020 to 4% in 2021 and further into 2% in 2022. In the context of the energy crisis, the lower nuclear availability in the French market increased the French premium and led to a fall in price divergence between the two markets, which further intensified the previous effect. Great Britain was a net exporter of electricity to France over most of 2022.
- The decrease in convergence between Spain and France in 2022 (27% in 2022) can be explained mainly by the lower availability of the French nuclear fleet, which increased the price premium over Spain. Moreover, the "Iberian exception" had a significant impact as well, as it supported a further decrease in price convergence during the second half of 2022. Italy and Greece have been coupled only since the middle of December 2020. Since then, convergence levels have been increasing year-on-year, with hourly prices nearly identical 29% of the time in 2022. The Nordic registered another year of significant drop in convergence levels in 2022. This marked a continuation of a trend visible since 2018, driven by growing trade imbalances of the four Scandinavian countries.

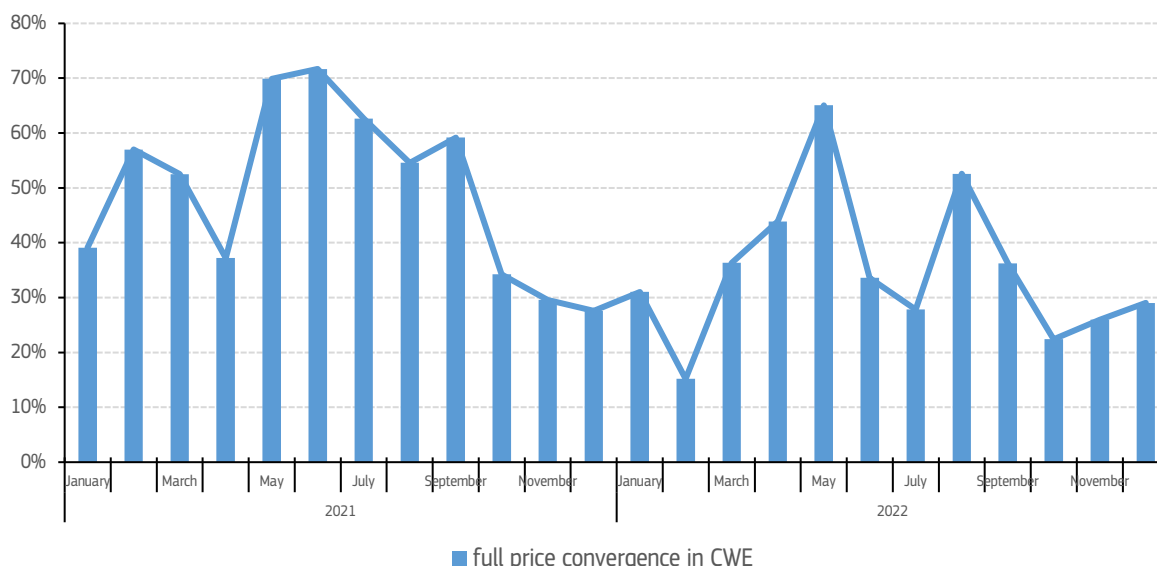
Figure 36 – Price convergence on day-ahead markets in selected regions as percentage of hours in a given year



Source: ENTSO-E, OTE, Nord Pool, Platts. The numbers in brackets refer to the number of bidding zones included. The CWE region comprises of BE, FR, NL and DE-LU-AT zones until October 2018, and separate DE-LU and AT zones since then. The CEE region includes CZ, SK, HU, RO bidding zones. The Baltic region includes EE, LV, LT bidding zones. The Nordic region includes 13 bidding zones of Norway, Sweden, Finland and Denmark.

- **Figure 37** demonstrates that price convergence is subject to seasonal fluctuations and that it changes from month to month. In the case of the CWE region, lower price convergence is observed during winter months when electricity consumption increases, and the grid is under greater stress due to higher loads. Winter months of 2022 are a case in point. However, convergence levels were also abnormally low in other months of 2022, mainly as the result of the energy crisis, fuelled by lower French nuclear generation. In turn, Germany's increased seasonally stronger wind and solar generation, had greater influence in prices in the context of the tightness of energy markets in Europe.

Figure 37 – Monthly full price convergence in the CWE region in 2022 and 2021



Source: ENTSO-E

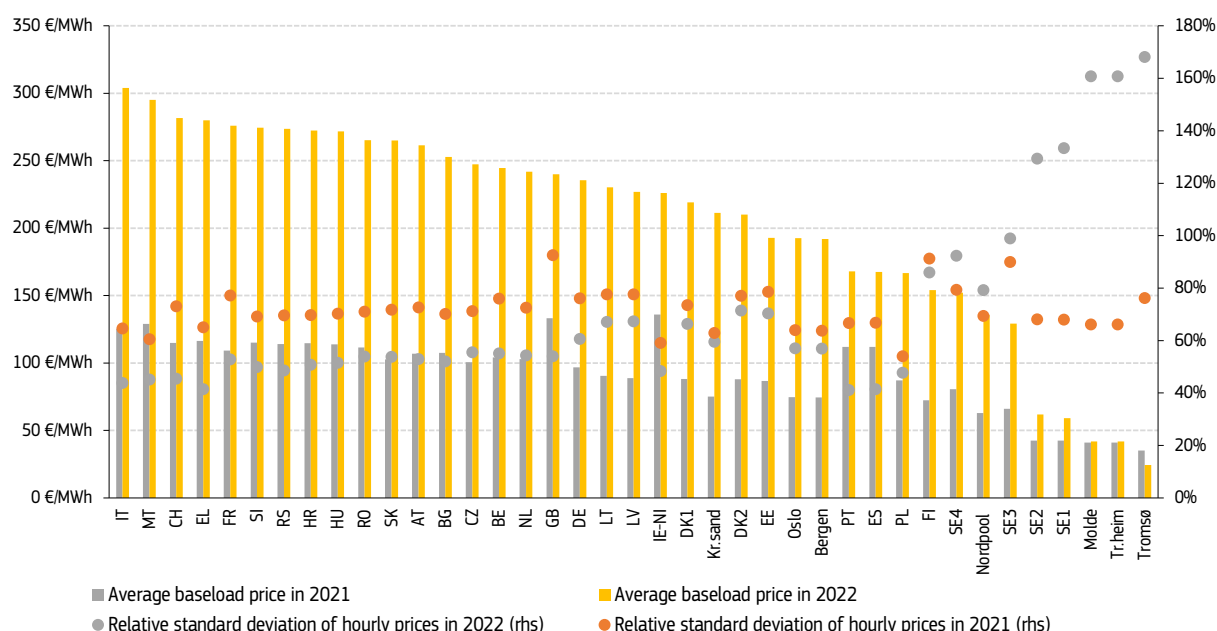
3.2 Average annual price levels and volatility

- **Figure 38** maps annual changes in average day-ahead baseload prices and in hourly price dispersion across European day-ahead markets. 2022 was a particular year due to the turmoil in energy commodity markets. The universal increase in the price of baseload electricity observed in 2022 can be attributed to higher fuel costs, fuelled by the

Russian invasion to Ukraine, combined with the subdued hydro and nuclear generation. In 2022, gas prices at TTF were on average traded 161% higher than in 2021, while emission allowances increased their price by 50% compared to the previous year. However, wholesale prices did not rise to the same extent. The highest prices in Europe were registered in markets dependent on gas for a large share of their electricity generation. Italy, with more than half of their electricity generation coming from gas, became the most expensive European market (304 €/MWh) in 2022. Italy also experienced a considerable yearly increase in prices (+142%).

- Southern Norwegian bidding zones, Slovakia, Latvia, Lithuania and France (+180% to +150%), registered the largest yearly increase in prices. Likewise, Italy, Greece, Croatia, Hungary; markets which largely rely on gas generation were also situated on the high end of the spectrum. Conversely, markets with large shares of hydro reservoir generation, registered the lowest prices in Europe. The Norwegian northern bidding zones Trondheim (NO3) and Tromsø (NO4) experienced the lowest prices in Europe (41 €/MWh and 24 €/MWh, respectively). Likewise, northern zones of Sweden registered also prices at the lower bound of the table. Iberian markets experienced lower increases in prices (+50%) than other markets, due to the implementation of the 'Iberian exception', from mid-June 2022.
- Markets at the higher end of the spectrum are typically markets that have a significant presence of gas-fired power plants in their generation mix (IT, MT, EL), or in the so-called energy islands which are relatively isolated areas dependent on imports (MT, IT) (sometimes a combination of both). Markets with spare coal and lignite generation capacity in their energy mix (PL, DE, CZ, BG) were able to weather to a certain extent the impact of the price increase. Gas prices undermined the competitive advantage of gas-fired power plants in Europe, improving comparative levels of coal generation (despite high carbon prices) intensifying the switch from gas to coal through most of 2022. The lowest prices were observed in the Nordic region, displaying also high levels of difference in prices.
- Most markets experienced higher levels of price volatility in 2022 than in 2021 (measured as relative standard deviation of hourly prices and plotted on the right-hand scale of the chart). This could be linked to the turmoil in the global energy commodity markets as a result of the Russian war in Ukraine and the subsequent events reducing the inflows of Russian gas to Europe. These factors, combined with a drought that reduced the hydrogeneration levels and lower generation from the nuclear fleet, brought prolonged periods of very high and volatile prices into the market. However, volatility in 2022 did not reach the peak levels that were observed in some of the Nordic markets in 2021. Volatility can greatly influence asset profitability in the electricity sector. For storage technologies, for instance, the greater the absolute spread between minimum and maximum prices in a day, the more they can earn by buying low and selling high.

Figure 38 – Changes in average baseload prices and hourly price volatility in European day-ahead markets between 2022 and 2021



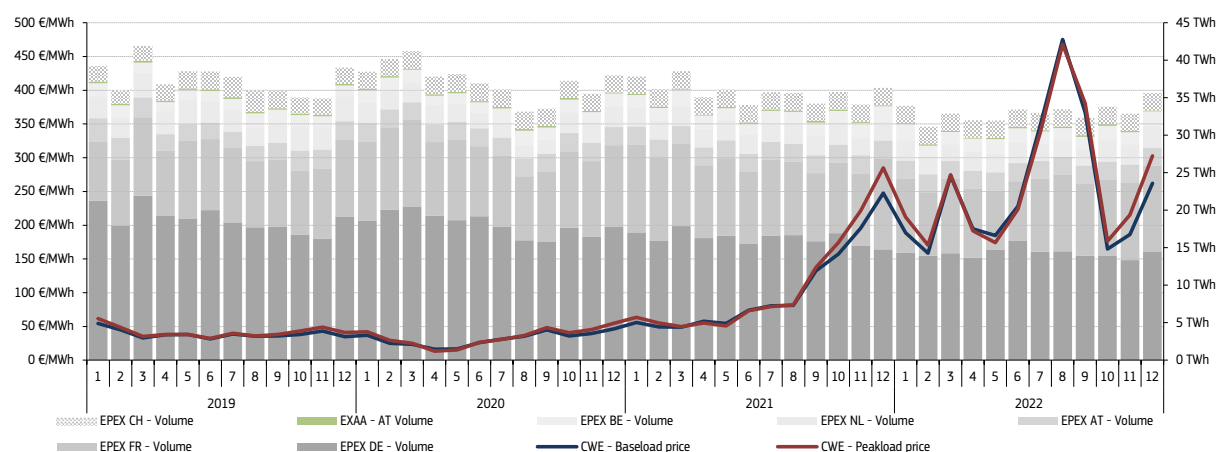
Source: ENTSO-E, OTE, Nord Pool, Platts. Italy is represented by the national average (PUN), the rest of the markets under observation correspond to bidding zones. Ireland has a common bidding zone with Northern Ireland (ISEM). Prices in Great Britain are represented by the N2EX power market.

4 Regional wholesale markets

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

- Compared to Q4 2021, average wholesale baseload electricity prices in Central Western Europe (CWE) increased by only 2% to 204 €/MWh in the reference quarter. Meanwhile, average peakload prices increased by 2% to 231 €/MWh.
- In France, nuclear generation availability drastically decreased vis à vis historical levels, despite increasing towards the end of the year. An unprecedented number of outages and some delay in the return dates of multiple reactors, due to corrosion problems or scheduled maintenance have taken the toll on the availability of the fleet. Among other factors, the reduced nuclear fleet availability kept French future contracts in premium over Germany (see **Figure 18**).
- In Germany, the government passed a regulation in September 2022 extending the life of hard-coal power plants (6.9 GW), enabling the return into the market until 31 March 2024, as a temporary emergency measure to support power availability in winter. Moreover, Lignite plants (total capacity of 1.9 GW) in the reserve were enabled to start operating in October. The country had previously planned to end the coal reserve by end of April 2023. The drop in power demand in Q4 2022 (-9%, see **Figure 4**) was the primary factor behind the fall in coal-fired generation in Germany during the reference quarter.
- In addition, to secure the security of supply during the winter season, Germany extended the use of the three remaining nuclear reactors (Isar-2, Neckarwestheim-2 and Emmsland) until mid-April 2023. As part of the scheduled nuclear phase-out plan, these plants were expected to cease operation at the end of 2022. Germany already closed three reactors at the end of 2021.

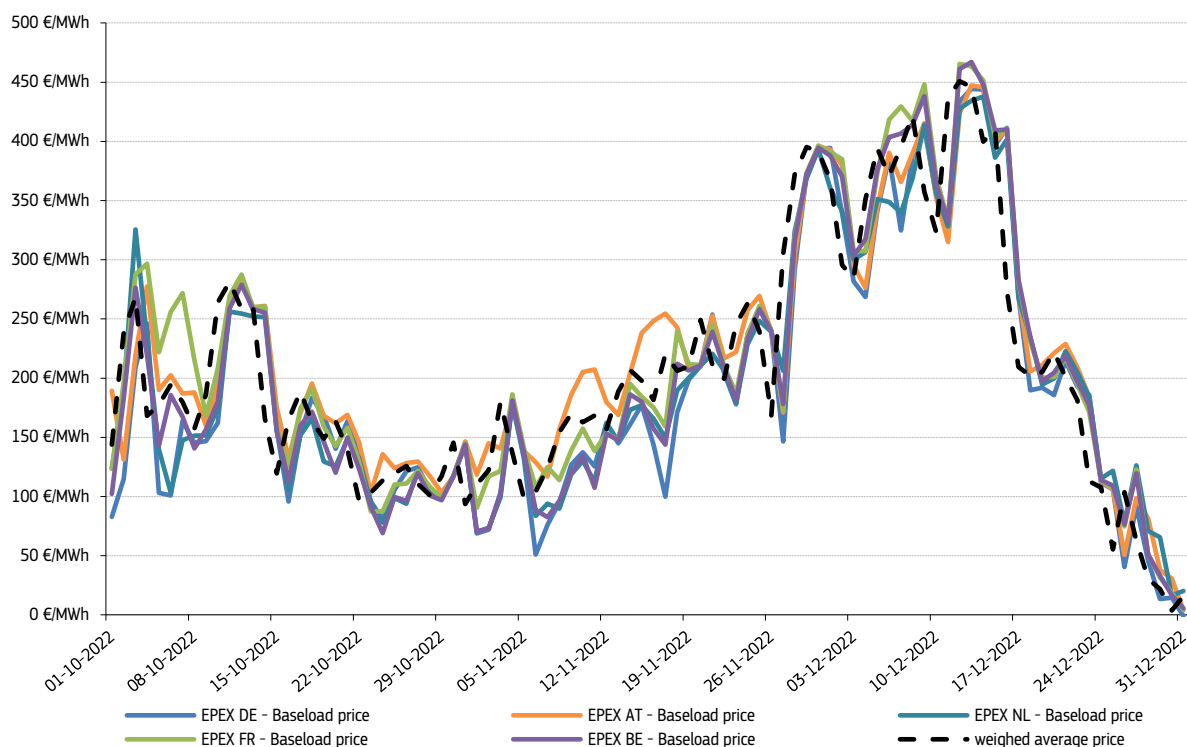
Figure 39 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



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

- **Figure 40** shows the daily average day-ahead prices in the region in the reference quarter. Daily average prices in CWE reached new highs in Q4 2022; however, not as high as the all-time peaks registered during Q3 2022. On 13 December, CWE prices rose 451 €/MWh following the corresponding increase of gas prices on the main European hubs and colder temperatures pushing demand up.

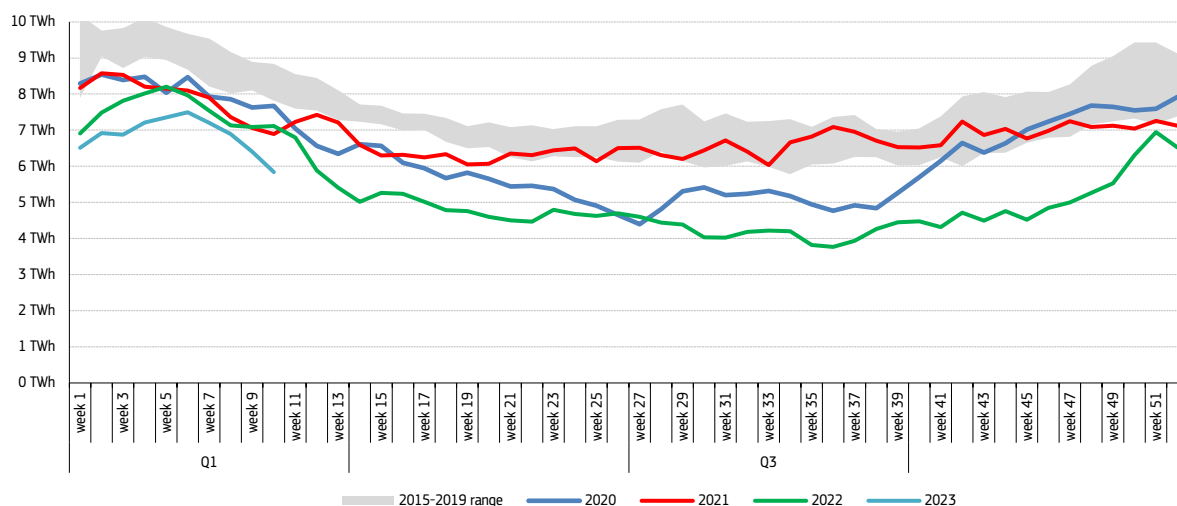
Figure 40 – Daily average power prices on the day-ahead market in the CWE region



Source: S&P Platts.

- As shown in **Figure 41**, French nuclear output was down by 26% (-23 TWh) year-on-year in Q4 2022. However, nuclear generation rose from 4.5 TWh in the first week of October 2022 to 6.9 TWh during the last week of December. Nuclear generation kept increasing into Q1 2023, reaching a high of 7.5 TWh in the second week of February, albeit below historical levels. Since then, generation has been falling through the rest of Q1 2023. The French nuclear output in 2022 (279 TWh) was the lowest since 1998. In February 2023, EDF confirmed its nuclear availability for 2023 (300-330 TWh), as the fleet experienced a high number of outages combined with scheduled maintenance in 2022.
- In Belgium, Doel 3 was the first nuclear reactor to be shut down as part of the phase-out plan in Q3 2022. The Belgium federal government had initially planned to decommission the existing nuclear capacity (6 GW) by 2025. Moreover, Tihange-2 (1 GW) was shut down at the end of January 2023. 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 41 – Weekly nuclear electricity generation in France

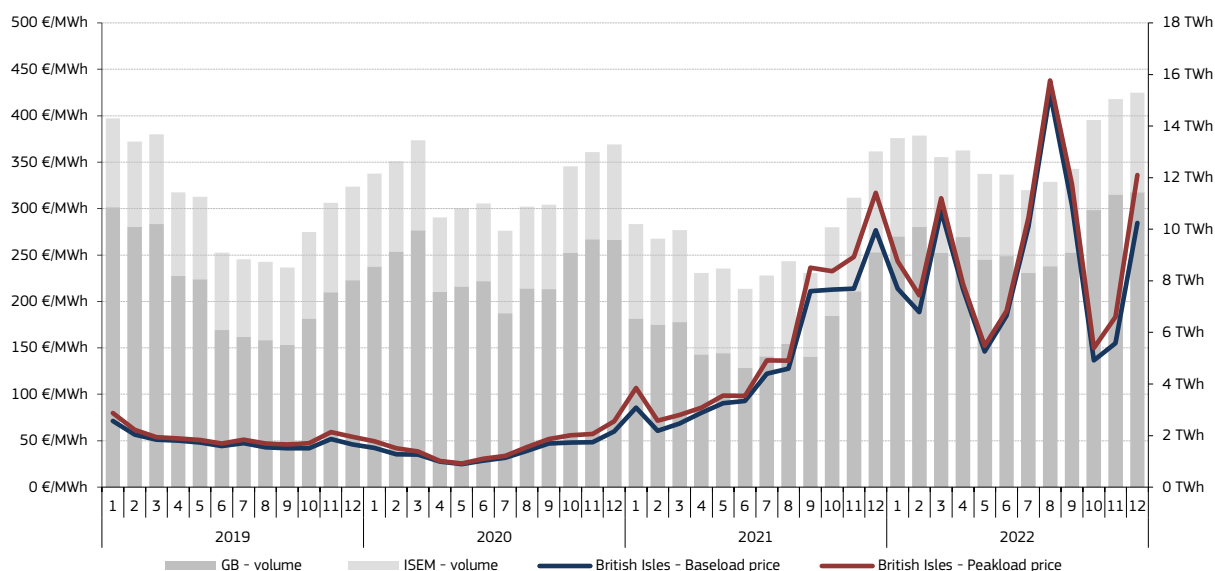


Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- **Figure 42** illustrates monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market of Ireland. Following the all-time highs in Q3 2022, monthly averages for both baseload and peakload power eased in October, but it rose again in November and December. In Q4 2022, lower wholesale electricity prices than in the continent, supported for a third quarter the change of traditional direction of flows between the British Isles and the continent. Q4 2022 saw again the British Isles acting as a net exporter to mainland Europe. Compared to Q4 2021, the average baseload price on the British Isles fell by 18% to 192 €/MWh during Q4 2022 and falling by 43% from Q3 2022.

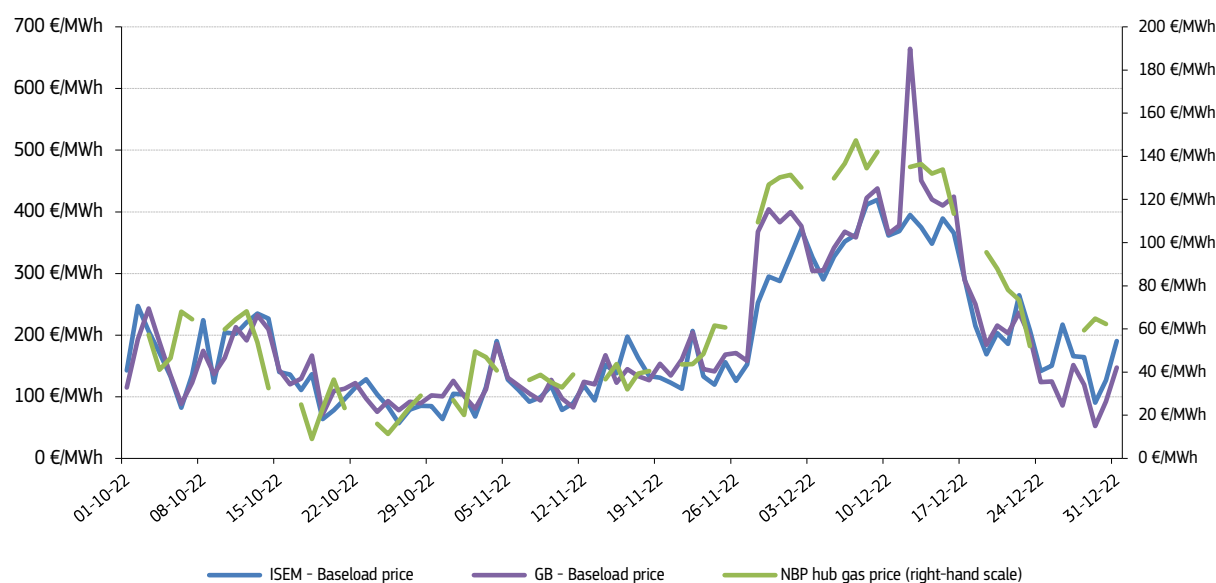
Figure 42 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 43** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices experienced strong volatility and reached new highs in December 2022, in line with other European markets. The highest value in Great Britain was registered on 12 December, driven by NBP prices, a rise of demand due to a cold snap and wind lulls, recording a new high of 664 €/MWh.

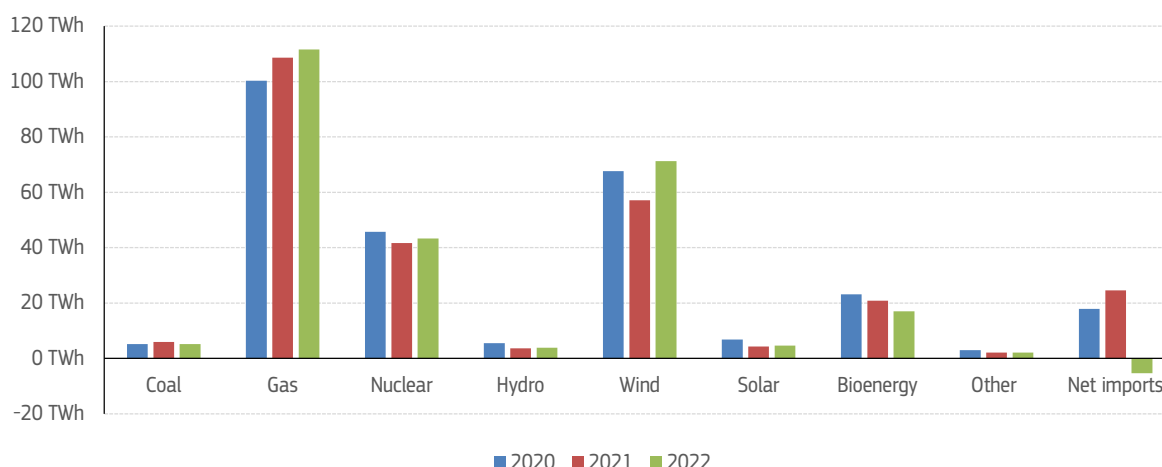
Figure 43 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool NZEX, SEMO

- **Figure 44** shows the impressive increase of electricity net exports during 2022, changing UK's traditional net importer position. UK also registered significant increases in gas and wind (both onshore and offshore) generation between 2021 and 2022. The renewable share rose from 35% in 2021 to 37% in 2022, supported by a surge in wind output (+25%). Nuclear generation was 4% higher in 2022. The share of net imports from the continent compared with total generation fell from 10% in Q3 2021 to -2% in 2022 (net exports). The position of coal dropped significantly (-13%). Gas generation registered a slight increase of 3% compared with 2021. Gas-fired and wind generation remained the largest share of generation mix (43% and 28%, respectively) during 2022.
- Two nuclear power plants ended generation between 2021 and 2022 (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 now expected to come online in 2027.

Figure 44 – Evolution of the UK electricity mix in 2020, 2021 and 2022

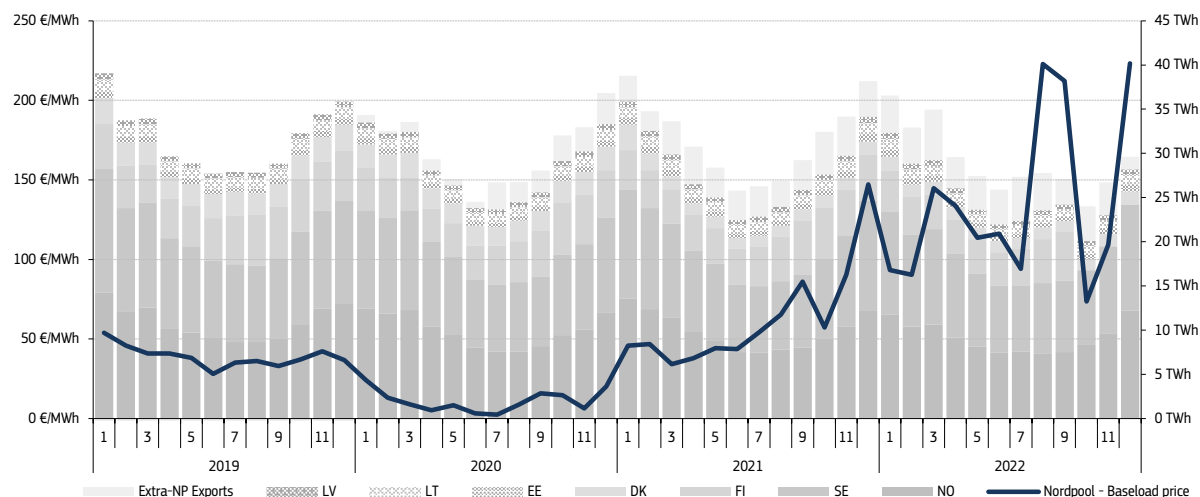


Source: BEIS. Positive values of cross-border flows indicate net imports

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

- As shown in **Figure 45**, Nordic prices reached a new all-time high of 223 €/MWh during December 2022 (slightly higher than the previous record in August 2022). Compared to Q4 2021, the average system baseload price surged by 38% from 98 €/MWh in the equivalent reference quarter.
- In Finland, the delayed commercial operation of Olkiluoto-3 nuclear power plant started on 16 April 2023. Olkiluoto-3 will significantly improve Finland's position, especially after Russian exports of electricity were suspended to Finland on 14 May 2022.

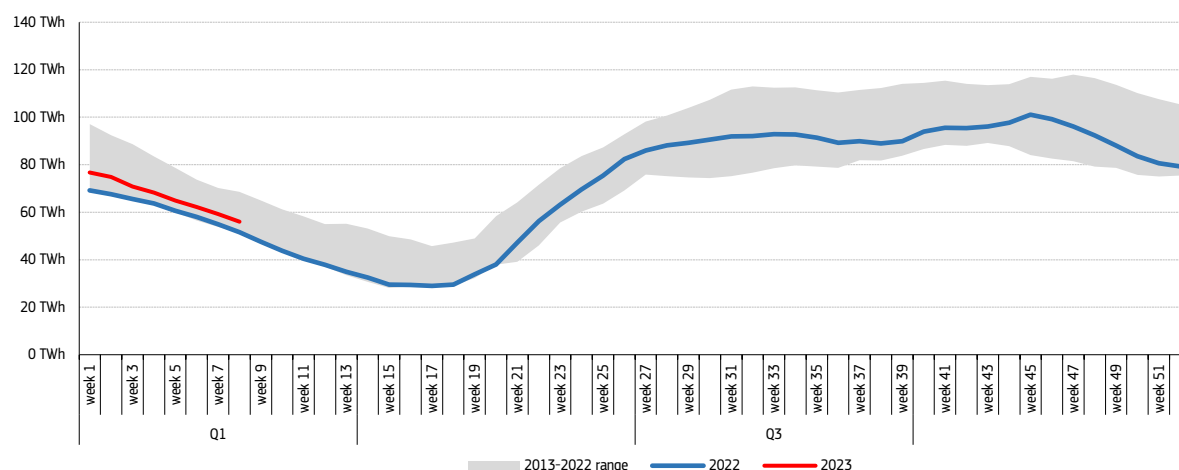
Figure 45 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 46** shows the weekly evolution of the combined hydro reservoir levels in the Nordic area (Norway, Sweden and Finland) in 2022 compared to previous nine years. After a dry summer, hydro stocks started to increase staying within the historical range in Q4 2022, albeit closer to the lower end of the range. Hydroelectric stocks reached a quarterly high of 101 TWh during the first week of November. Since then, stocks have fell to above 80 TWh, during the last week of December 2022, aligning with expected seasonal levels during the rest of the winter. Overall, Nordic hydropower stocks recorded a 14% improvement in Q4 2022 compared to Q4 2021.

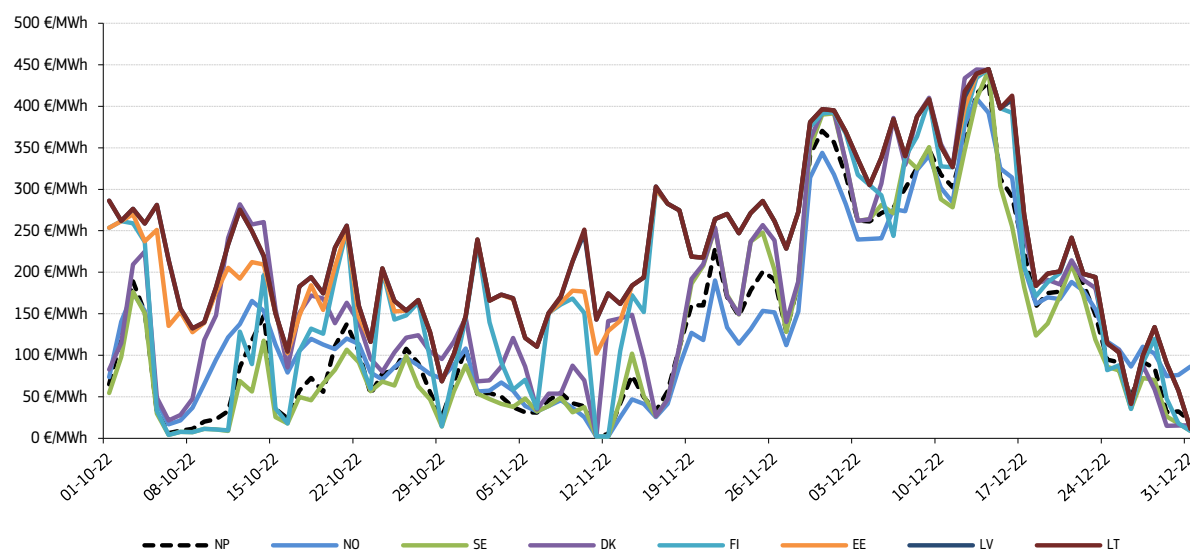
Figure 46 – Nordic hydro reservoir levels in 2022, compared to the range of 2013-2022



Source: Nord Pool spot market

- **Figure 47** shows that average daily prices across Northern Europe continued to display an unprecedented degree of divergence and volatility throughout Q4 2022. The highest daily regional price registered in the reference quarter reached an all-time high at 444 €/MWh on 14 December, whereas the lowest daily regional price registered was at 4 €/MWh on 6 October. The highest spike was recorded in Finland and the Baltic markets on 14 August (445 €/MWh).

Figure 47 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

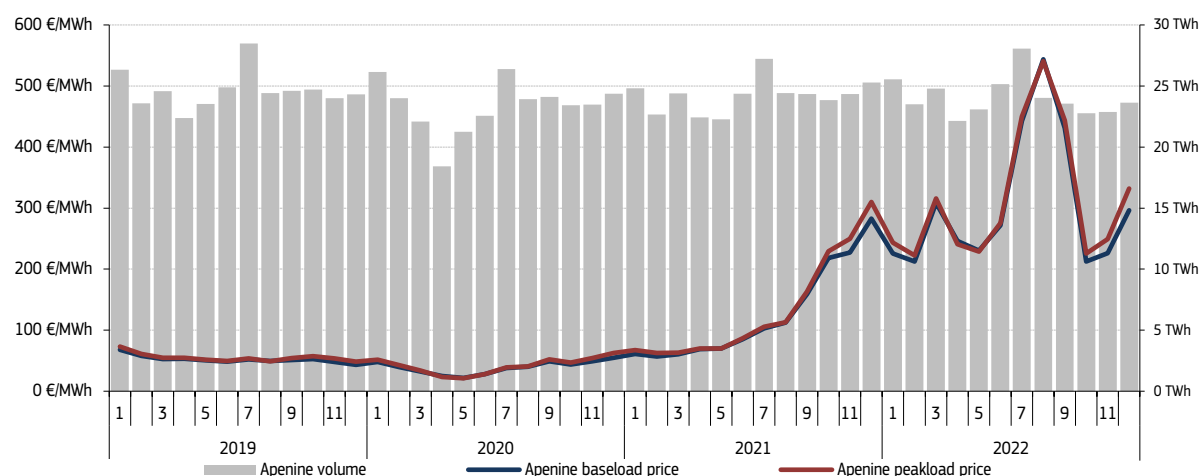


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Following unprecedented highs in the previous quarter (Q3 2022), the Italian monthly average baseload electricity prices (**Figure 48**), fell to 269 €/MWh in Q4 2022. The average baseload price was only 1% higher compared to Q4 2021. Trading volumes recorded a fall of 6% with respect to the previous fourth quarter. Meanwhile, average peak-load prices increased by 2% to 263 €/MWh.

Figure 48 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy

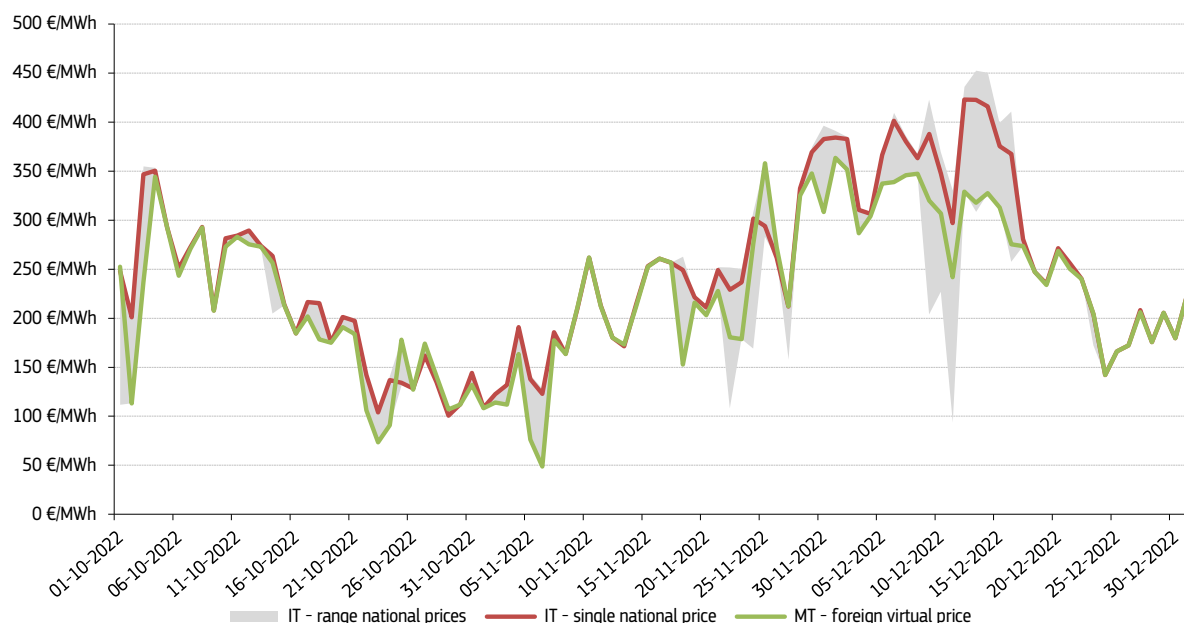


Source: GME (IPEX)

- Figure 49** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The national average stayed mostly between 180 and 300 €/MWh during the reference quarter. Prices reached an all-time high value at 423 €/MWh on 12 December, due to high gas prices in Europe.
- Italy is one of the largest producers of electricity from gas in the EU (gas-fired generation represented 57% of the total generation in Italy during Q4 2022). Rising commodity prices, especially gas, played an important role in the surge of prices in 2022.
- 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 has formed the upper boundary of the band of regional prices. However, as visible in **Figure 49**, during most of Q4 2022, prices in the Maltese area were not in the upper bound of regional prices. Moreover, at times, they were positioned at the lower end instead. On the other hand, the Sardinian zone has been

forming the lower boundary, quite far away from the Italian single national price (PUN), supported in part, by the isolated effect of the island zone with respect to the continent.

Figure 49 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

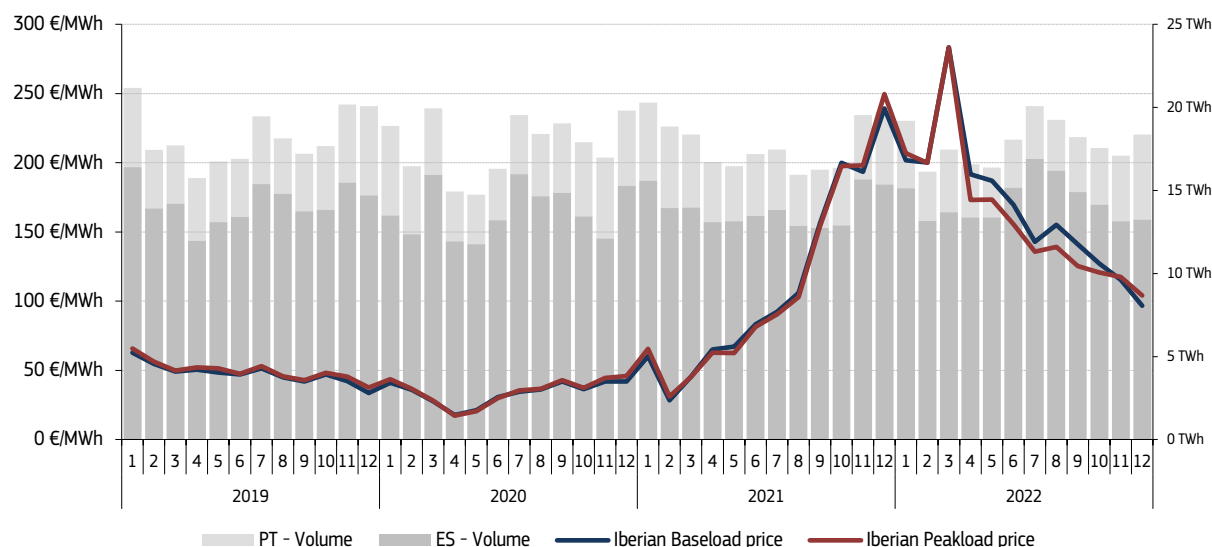


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- **Figure 50** reports on monthly average baseload and peakload contracts in Spain and Portugal. Since the start of the ‘Iberian exception’ in mid-June, prices have been falling. Compared to Q4 2021, the average baseload price fell by 46% to 113 €/MWh in Q4 2022. Peak prices decreased by 47% to 114 €/MWh. Trading activity registered a fall of 5% compared with the previous Q4.

Figure 50 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula

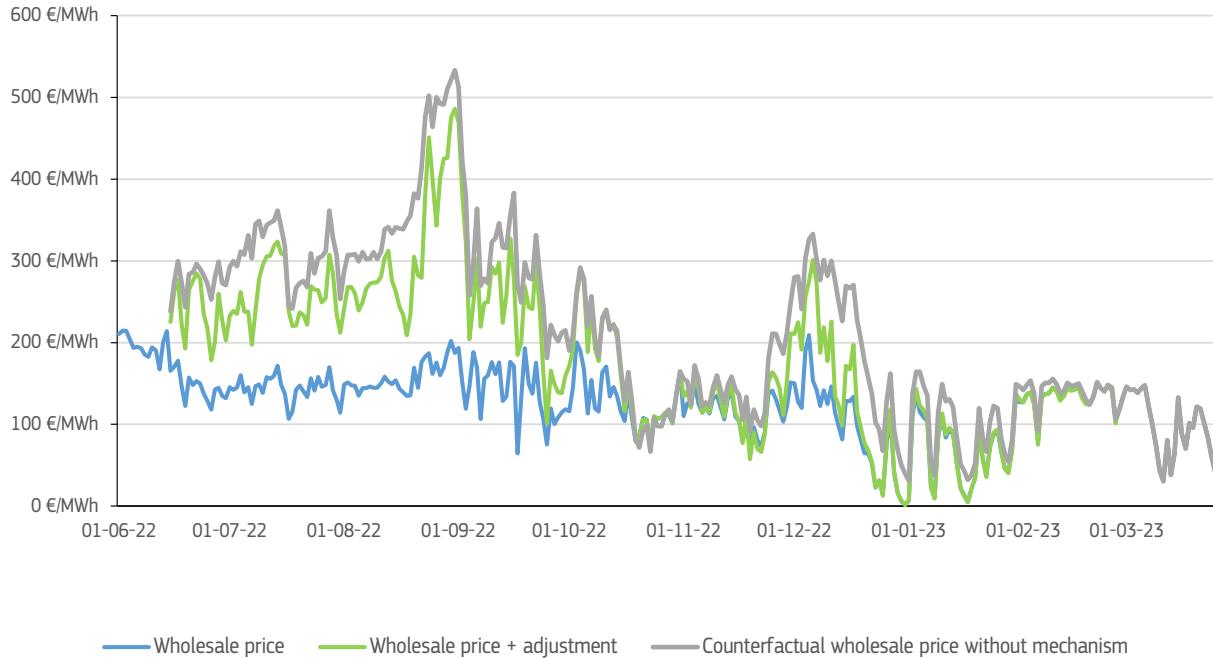


Source: Platts, OMEL, DGEG

- **Figure 51** reports on the developments in wholesale prices since the start of the Iberian mechanism (15 June 2022) up to end of March 2023. Overall, since the start of the exception, the wholesale electricity price has averaged 121 €/MWh, registering a 42% decrease in comparison with the average counterfactual wholesale price without the

mechanism. Also, final consumers with tariffs linked with the wholesale price have paid an average compensation of 53 €/MWh, thus these consumers have benefitted by 17% from the measure. The measure has rarely been activated during 2023 (due to prices lower than the subsidy price) and it was de facto inactive during March 2023. The extension of the measure for the next 12 months is in the process of approval.

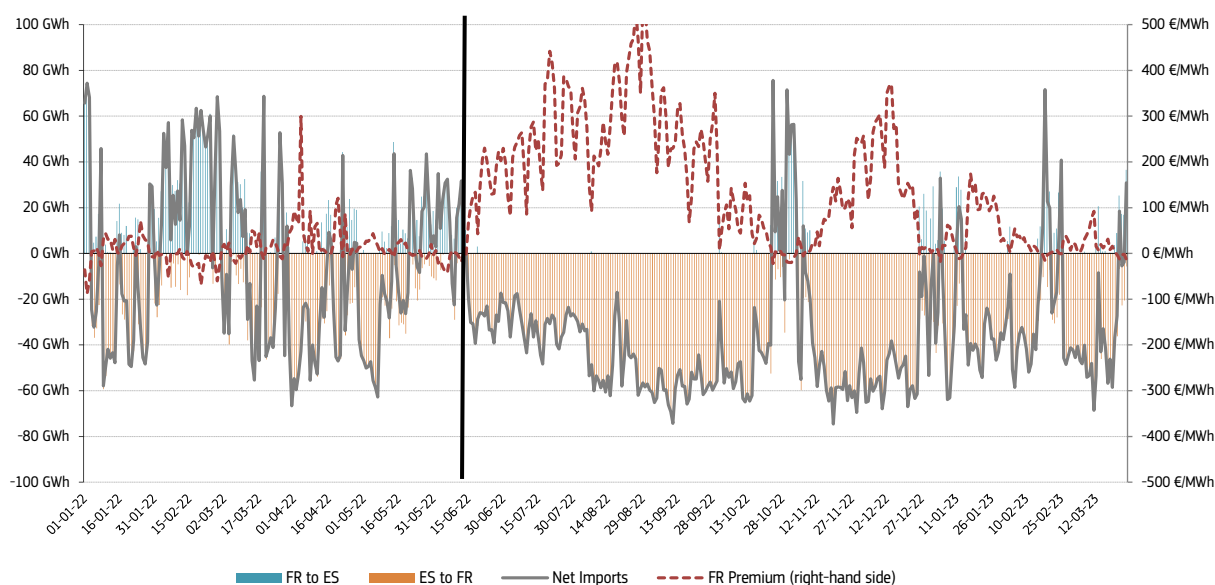
Figure 51 – Iberian market day-ahead electricity prices



Source: OMIE, DGEG

- **Figure 52** shows daily electricity flows between France and Spain and price differentials between the two bidding zones from January 2022 to end of March 2023. Since the introduction of the measure and along with the reduction of the traditional French premium, exports from France to Spain have been severely reduced, while flows from Spain to France have risen. In general, the subdued nuclear availability of the French nuclear fleet has made electricity prices higher in France. Thus, changing France's traditional net exporter into a net importer role, not only from Spain but also from other Member States and the United Kingdom (see **Figure 33**). However, certain periods of lower demand and mild weather during Q4 2022 and Q3 2021 have supported a return of net imports from France.

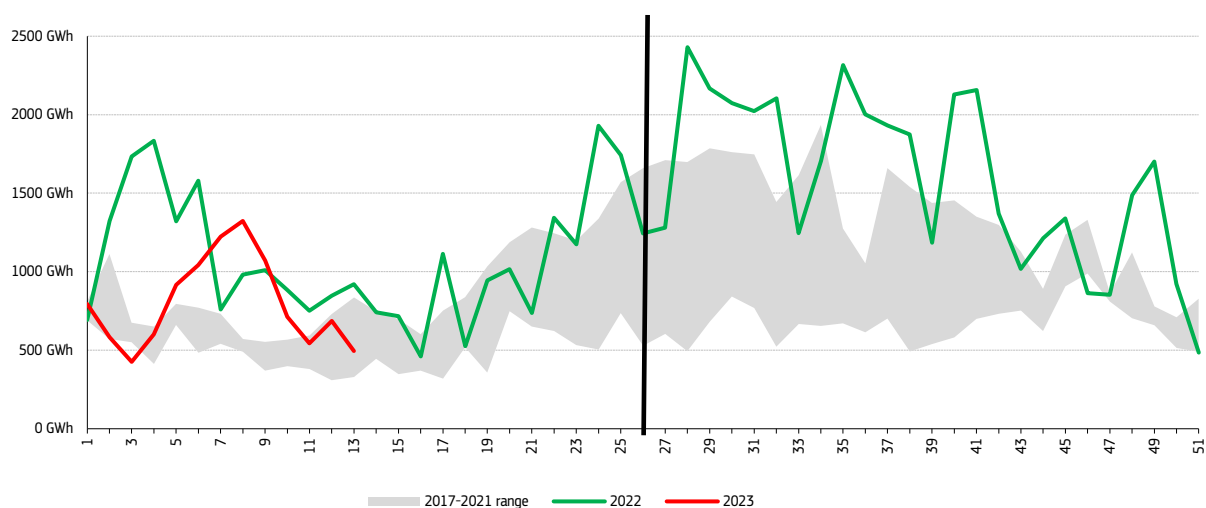
Figure 52 – Daily electricity import balance for Spain and France and price differentials between them in 2022 and 2023 (March)



Source: ENTSO-E

- **Figure 53** reports the evolution of gas-fired generation in Spain during 2022 and 2023 (January – March) compared to a range of the previous five years (2017–2021). From 15 June 2022 to end of December 2022, gas-fired generation rose by 47% 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). Gas-fired generation levels fell by 24% in Q1 2023, compared with Q1 2022. The increase in gas-fired generation in the second half of 2022 should be put in the context of 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 53 – Weekly gas-fired electricity generation in Spain

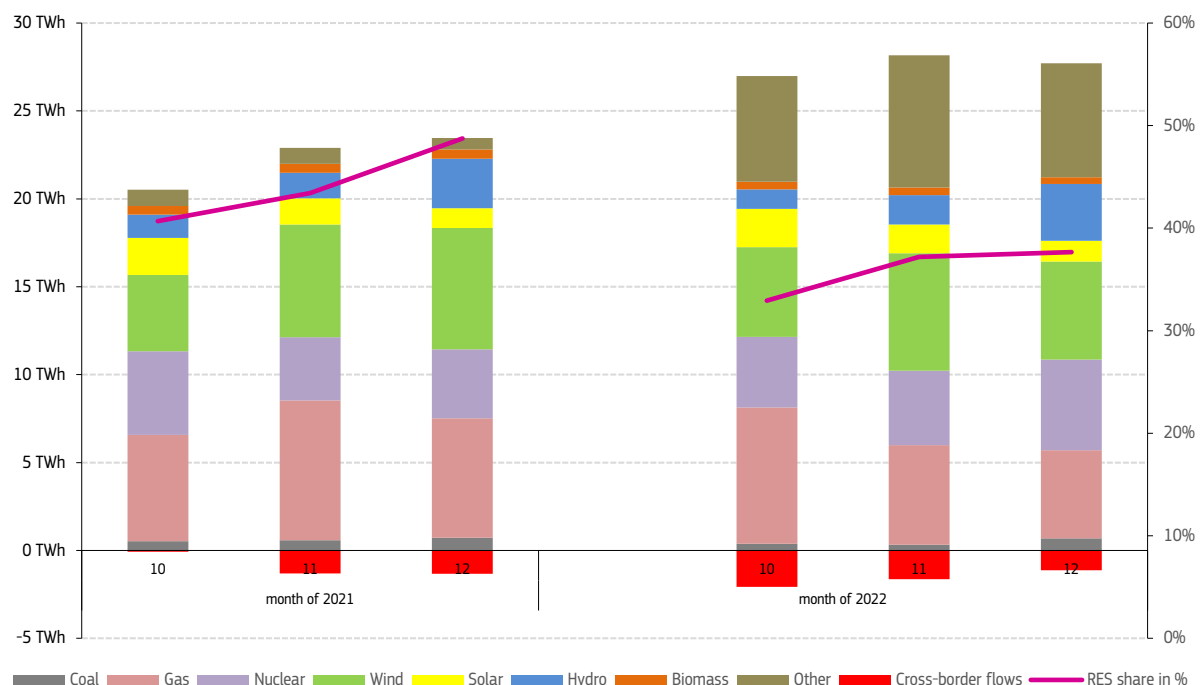


Source: REDEE

- **Figure 54** displays the evolution of the monthly electricity generation mix in Spain during the fourth quarter of 2022, as well as during the same period of the previous year. Net generation increased by 24% year-on-year. The share of renewable electricity sources fell to 36% in Q4 2022 from an average of 44% in Q4 2021. However, solar generation still managed to increase by 6%. Gas generation fell by 11% (-2 TWh) compared with Q4 2021, covering a share of 22% of the total generation in Q4 2022. The reduced remaining coal capacity registered a 23% decrease

in output (-0.5 TWh) year-on-year in Q4 2022. Nuclear generation increased its output by 9% and covered a share of 16% of the total generation. In Spain, net exports accounted for 6% of the total generation during the fourth quarter of 2022.

Figure 54 – Monthly evolution of the electricity generation mix in Spain in Q4 of 2021 and 2022

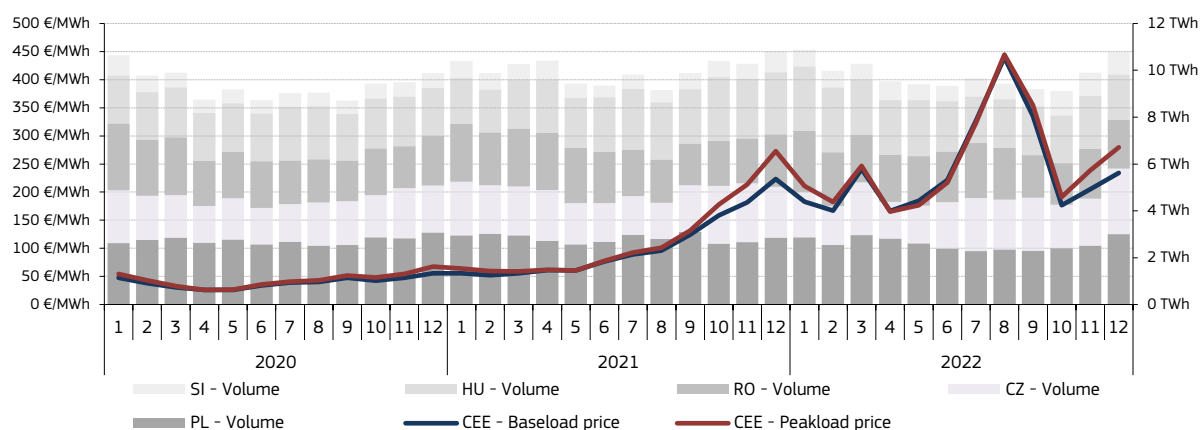


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- **Figure 55** shows the evolution of average monthly prices for baseload power in Central Eastern Europe in Q4 2022. When compared to Q4 2021, the average baseload price in the reference quarter rose by 9% to 205 €/MWh. Price in Q4 2022 fell by 42% in comparison with the average in the previous quarter (Q3 2022). Traded volumes in the reference quarter fell by 7% compared to the previous Q4.

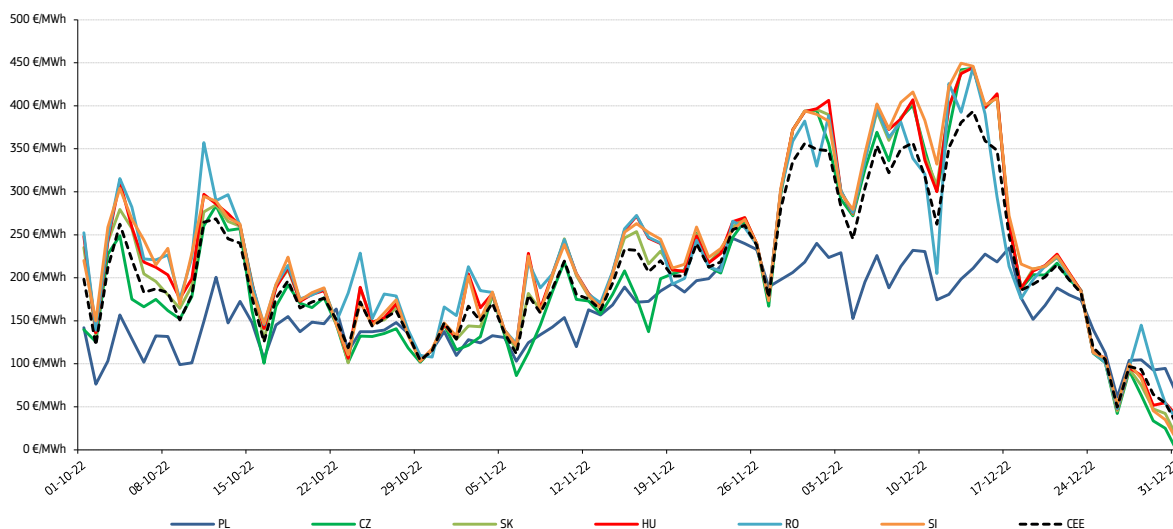
Figure 55 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 56** shows that daily average baseload prices in the markets (CZ, HU, RO, PL, SK, SI) registered high volatility during Q4 2022. CEE prices moved mostly between 150 and 255 €/MWh in Q4 2022. In December, prices rose until they reached a quarterly peak on 14 December (393 €/MWh). The Polish market decreased its discount towards CEE prices from an average -149 €/MWh in Q3 2022 to -48 €/MWh. High electricity prices also affected Member States with reduced exposure to gas, such as Poland (although to a lesser extent than markets relying on gas).

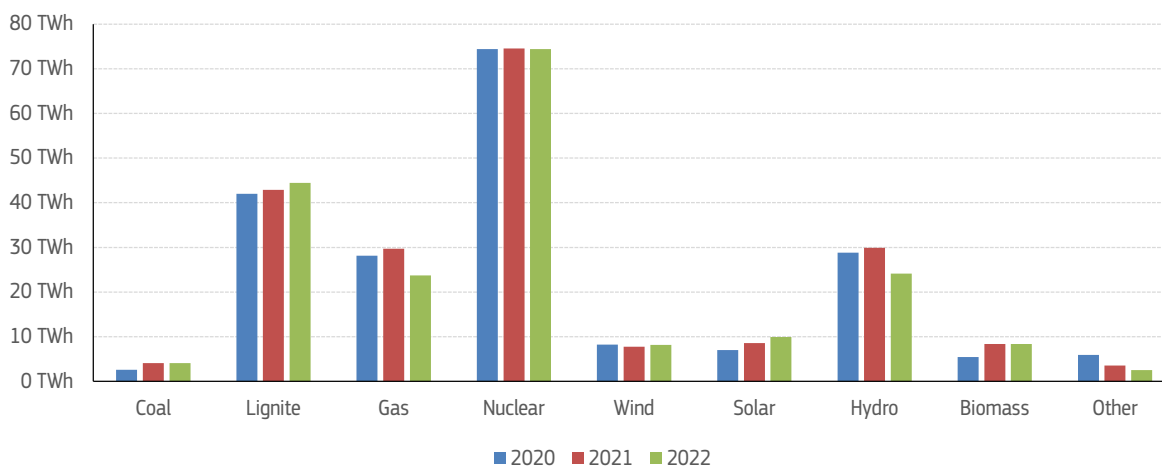
Figure 56 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 57** shows the electricity generation mix of the CEE region (excluding Poland) in the last years. Hydro-power generation fell considerably (-19%) in 2022 compared with 2021. A rise in solar (+16%) and wind (+5%) generation compensated hydro losses during 2022. However, the renewable energy share slightly dropped compared with 2021 (from 26% to 25%). In 2022, nuclear power continued to be the primary technology for generating electricity, accounting for 37% of the total generation. This percentage remained unchanged from the previous year, 2021. Nuclear power had a significant presence in all five markets.

Figure 57 – Evolution of the electricity mix in the CEE region (excluding Poland) in 2020, 2021 and 2022



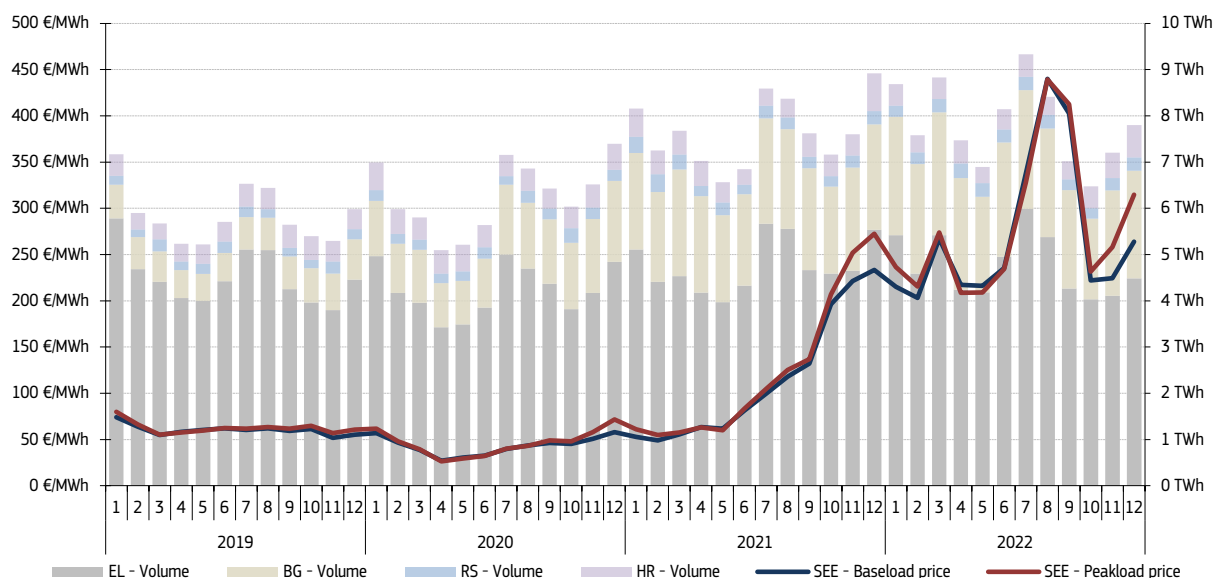
Source: Eurostat, ENTSO-E.

- 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 70% in 2022 compared to 71% in 2021. Renewables increased their share from 18% in 2021 to 22% in 2022, thanks to booming solar generation (+109%) and the increase in wind (+16%), despite a drop in hydro (-3%) and biomass (-3%) generation. Gas decreased its share in the mix from 9% in 2021 to 7% in 2022, underlining the limited short-term potential for fuel switching. Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations.

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

- **Figure 58** shows the average quarterly baseload price rose by 9% year-on-year to 236 €/MWh in Q4 2022, 40% lower than the all-time highs of Q3 2022. The average quarterly peakload price rose 10% above Q4 2021 levels to 268 €/MWh. Marginal costs of gas generation in countries like Greece, with high levels of gas-fired generation, supported elevated energy prices.

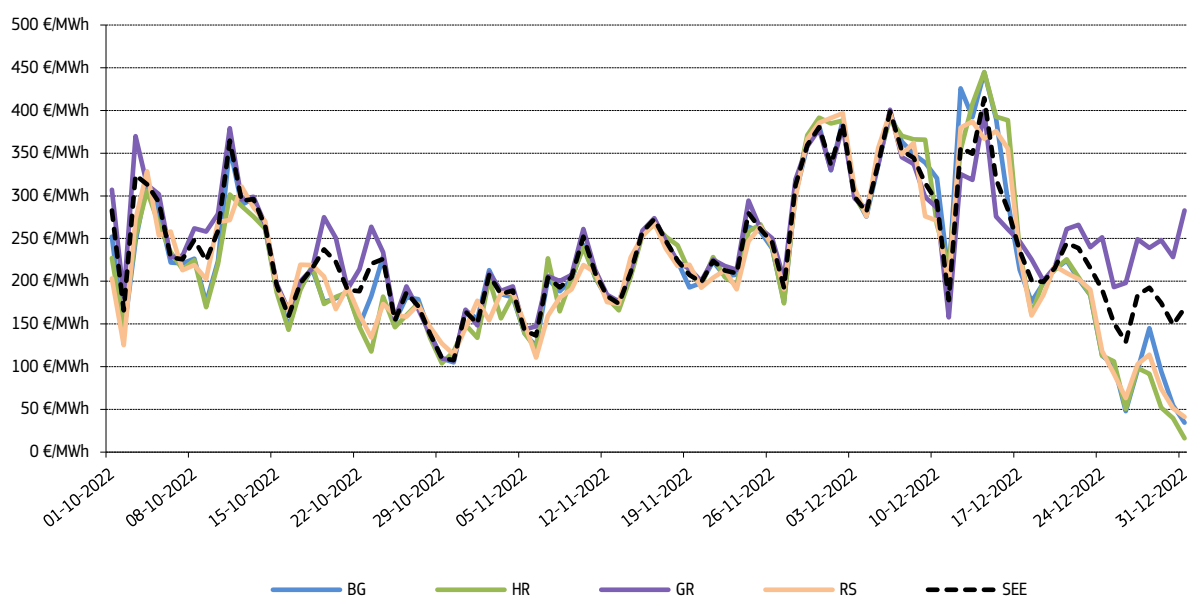
Figure 58 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- As shown in **Figure 59**, Greek day-ahead prices remained at the upper bound of the South-Eastern Europe markets in Q4 2022, registering a notorious divergence from the rest of the markets in the second half of December. Prices increased throughout the quarter, line with the rest of Europe, reaching a peak of 414 €/MWh on 14 December. Prices started to decline in second half of December, on the drop of gas prices combined with lower demand (Greek prices being the exception as explained above).

Figure 59 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia

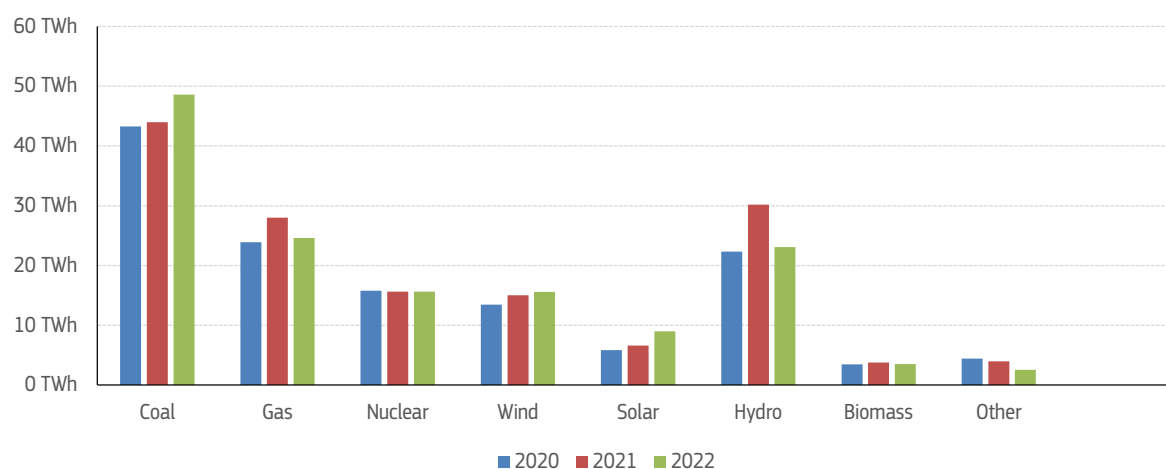


Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 60** shows the combined electricity generation mix of the SEE region in the last years. In 2022, coal and lignite generation increased by 11% its year-on-year output (+5 TWh). Gas output fell by 12% (-3 TWh), while nuclear generation remained practically unchanged. Hydro output experienced a setback of 7 TWh compared with

2021. The share of coal and lignite in the regional mix increased from 30% in 2021 to 34% in 2022. Renewable penetration fell from 38% in 2021, to 36% in 2022, on subdued hydro generation in the region (-23% on yearly basis), despite an increase in solar (+36%) and wind (+4%) output.

Figure 60 – Evolution of the electricity mix in the SEE region in 2020, 2021 and 2022



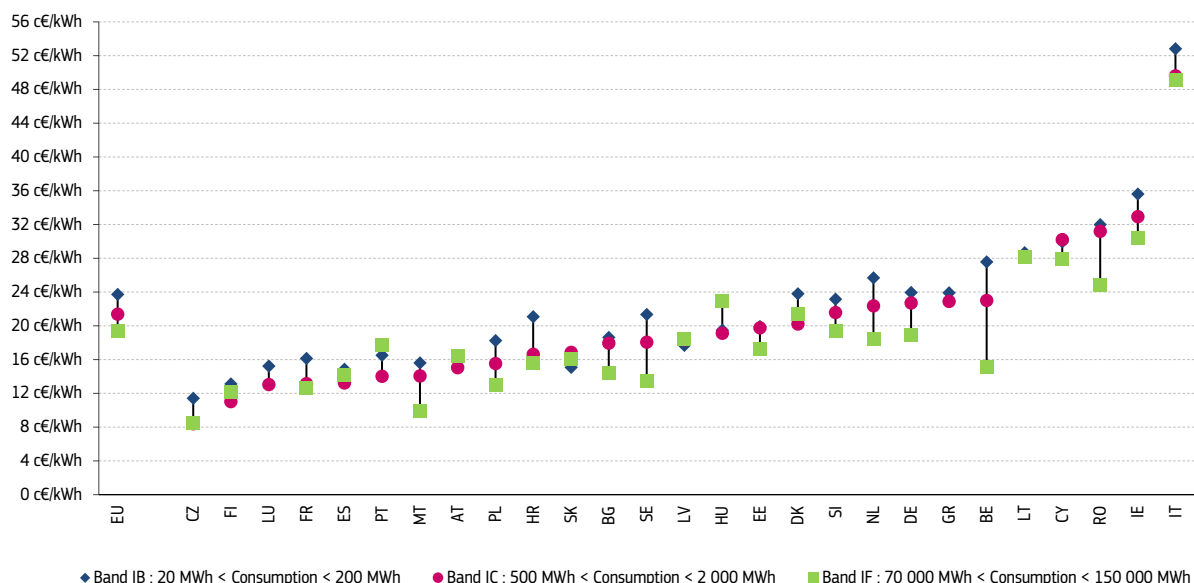
Source: Eurostat, ENTSO-E

5 Retail markets

5.1 Retail electricity markets in the EU

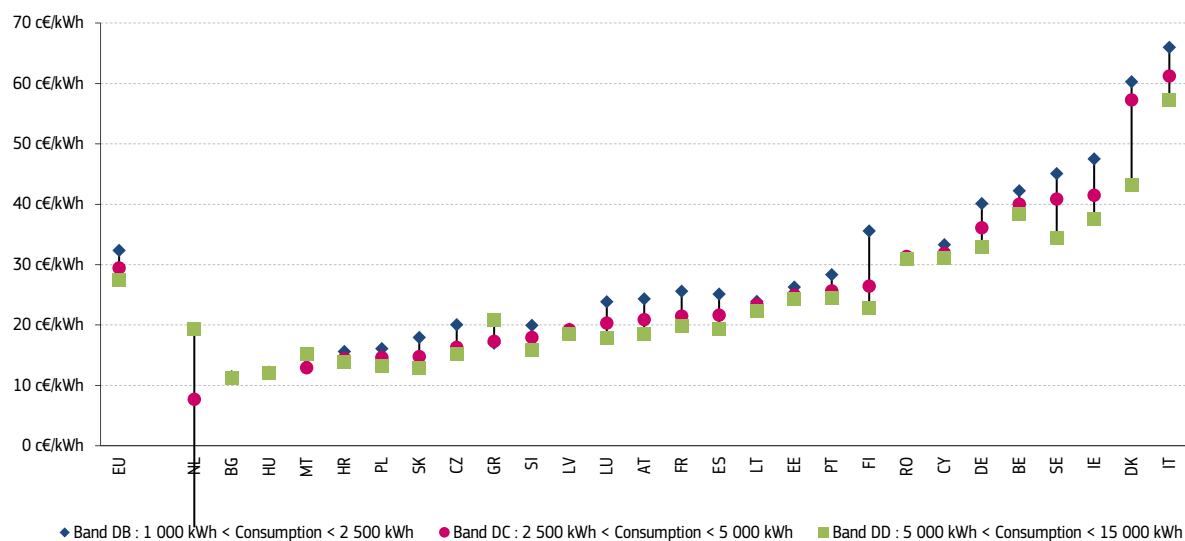
- High wholesale electricity prices resulted in rising consumer bills for households, impacting the industry sector as well. Increasing wholesale prices in 2022 put upward pressure on retail prices, as high wholesale prices were passed through into consumer contracts. Government interventions in some Member States alleviated the bill for consumers. The ease in wholesale prices registered in Q4 2022 alleviated the pressure on retail prices, but the price spikes in early December might have slowed down the recovery pace. However, further reduction could be expected as prices fell substantially during the first quarter of 2023.
- **Figures 61 and 62** display the *estimated* retail prices in December 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 first half of 2022) 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, Austrian, Slovakian and Latvian industrial prices are an exception, while Greece and the Netherlands prices are an exception for the household consumers.
- Smaller industrial consumers (band IB) were estimated to pay the highest prices in Italy (52.8 c€/kWh) and Ireland (35.6 c€/kWh), followed by Romania and Cyprus (32.0 and 29.9 c€/kWh respectively). The lowest prices in the same category were estimated to be in Czechia (11.5 c€/kWh) and Finland (13.1 c€/kWh). The ratio of the largest to smallest reported price was close to 5:1. Compared to December 2021, the average estimated EU retail price for the IB band rose by 33% to 23.7 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 (49.1 c€/kWh), followed by Ireland and Lithuania (30.4 and 28.1 c€/kWh). Czechia and Malta (8.5 and 10.0 c€/kWh) were assumed to have the lowest prices, with Finland and France (12.2 and 12.7 c€/kWh) coming close behind. The ratio of the highest to lowest price for large industrial consumers was above 5:1 for this consumer type. Compared to December 2021, the average estimated EU retail electricity price for the IF band rose by 55% to 19.4 c€/kWh. It is pertinent to note that the Italian price estimations were significantly impacted by the high HICP levels for electricity during the fourth quarter of 2022, which could plausibly account for the sharp rise in the estimated prices.
- In the household segment, Italy (57.3 c€/kWh) was estimated to have the highest electricity price for large consumers (band DD), followed by Denmark (43.2 c€/kWh), and Belgium (38.4 c€/kWh) in the third place. The lowest prices for big households were estimated for Bulgaria (11.2 c€/kWh), Hungary (12.0 c€/kWh) and Slovenia (12.9 c€/kWh). Compared to December 2022, the average estimated EU retail electricity price for the DD band rose by 19% to 27.4 c€/kWh. In the case of small households, Italy was estimated to have the highest prices (66.0 c€/kWh), followed by Denmark (60.3 c€/kWh) and Ireland (47.5 c€/kWh); while Bulgaria (11.5 c€/kWh), Hungary (12.0 c€/kWh) and Malta (14.7 c€/kWh) were on the other side of the price spectrum. In the Netherlands, a price of -13.5 c€/kWh was estimated for small size consumers, connected to government subsidies and allowances. Compared to December 2021, the average estimated EU retail electricity price for the DB band rose by 14% to 32.4 c€/kWh.

Figure 61 – Estimated industrial electricity prices, December 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 62 – Estimated household electricity prices, December 2022 – all taxes included

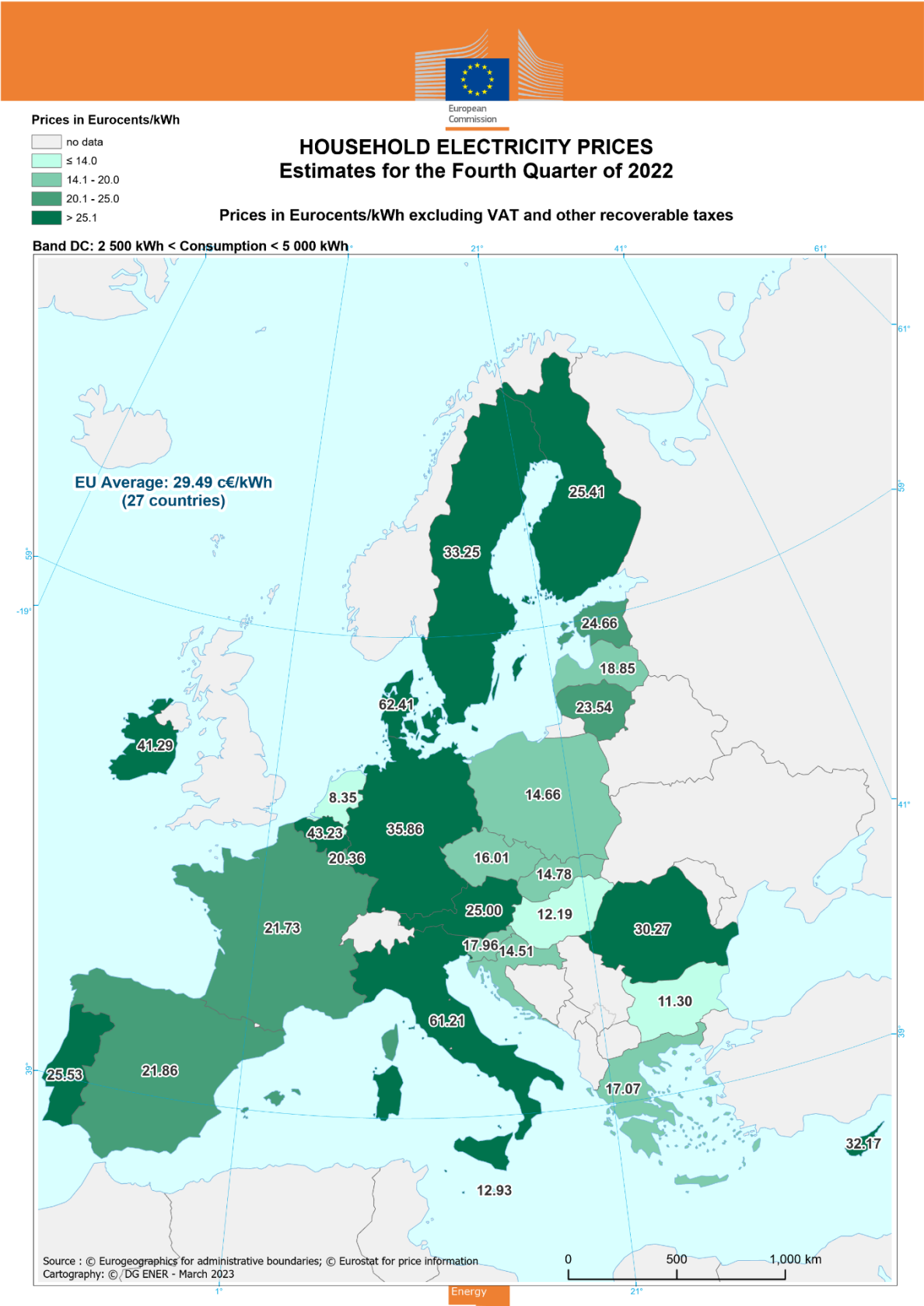


Source: Eurostat, DG ENER

- Figures 63 and 64** display the **estimated** electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the fourth quarter of 2022. In the case of household prices, Denmark topped the list (62.4 c€/kWh), followed by Italy (61.2 c€/kWh) and Belgium (43.2 c€/kWh). The Netherlands was estimated to have the lowest quarterly prices (8.4 c€/kWh). Bulgaria (11.3 c€/kWh) and Hungary (12.2 c€/kWh) followed the list of Member States with the cheapest estimated household electricity prices. The EU average increased by 21% to 29.5 c€/kWh in the reference quarter compared to Q4 2021. The largest year-on-year increases in the household category were estimated in Italy (+138%), Romania (+95%) and Denmark (+70%). Year-on-year falls were estimated for the Netherlands (-52%), Spain (-30%) and Greece (-24%). See **Figure 65** for more details on household prices in EU capitals.

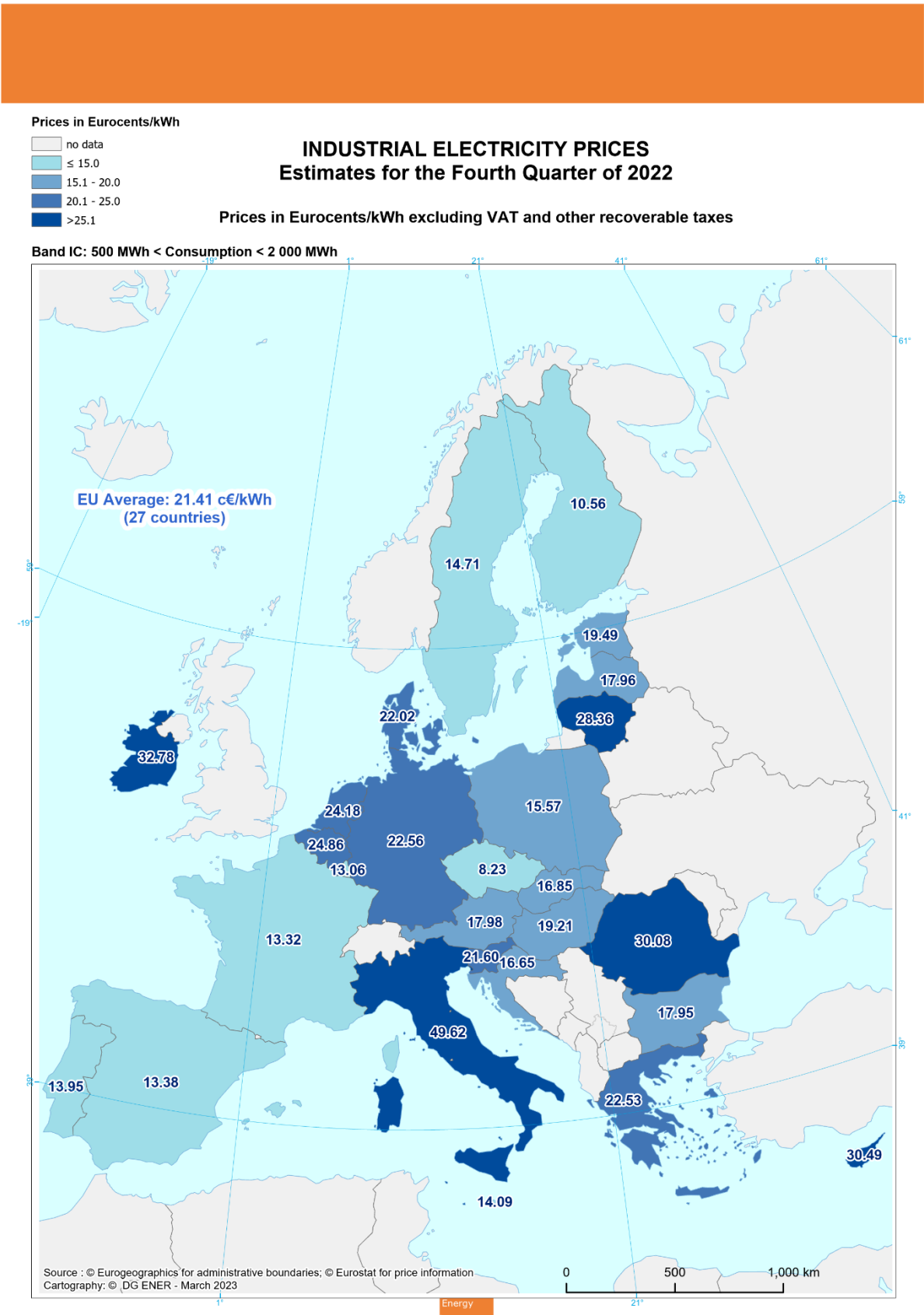
- In the case of mid-sized industrial consumers, Czechia was assessed to have the most competitive price in Q4 2022 (8.2 c€/kWh), followed by Finland and Luxembourg (10.6 and 13.1 c€/kWh, respectively). Meanwhile, Italy (49.6 c€/kWh), Ireland (32.8 c€/kWh) and Cyprus (30.5 c€/kWh) stood at the other end of the spectrum. At 21.4 c€/kWh, the average retail price for industrial customers in the EU in the reference period rose by 43% compared to Q4 2021. Italy (+146%), Romania (+140%) and Lithuania (+103%) marked the largest year-on-year increases in the industrial consumer category. Year-on-year falls were estimated for Spain (-17%), Greece (-12%) and Czechia (-5%).

Figure 63 – Estimated household Electricity Prices, fourth quarter of 2022



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

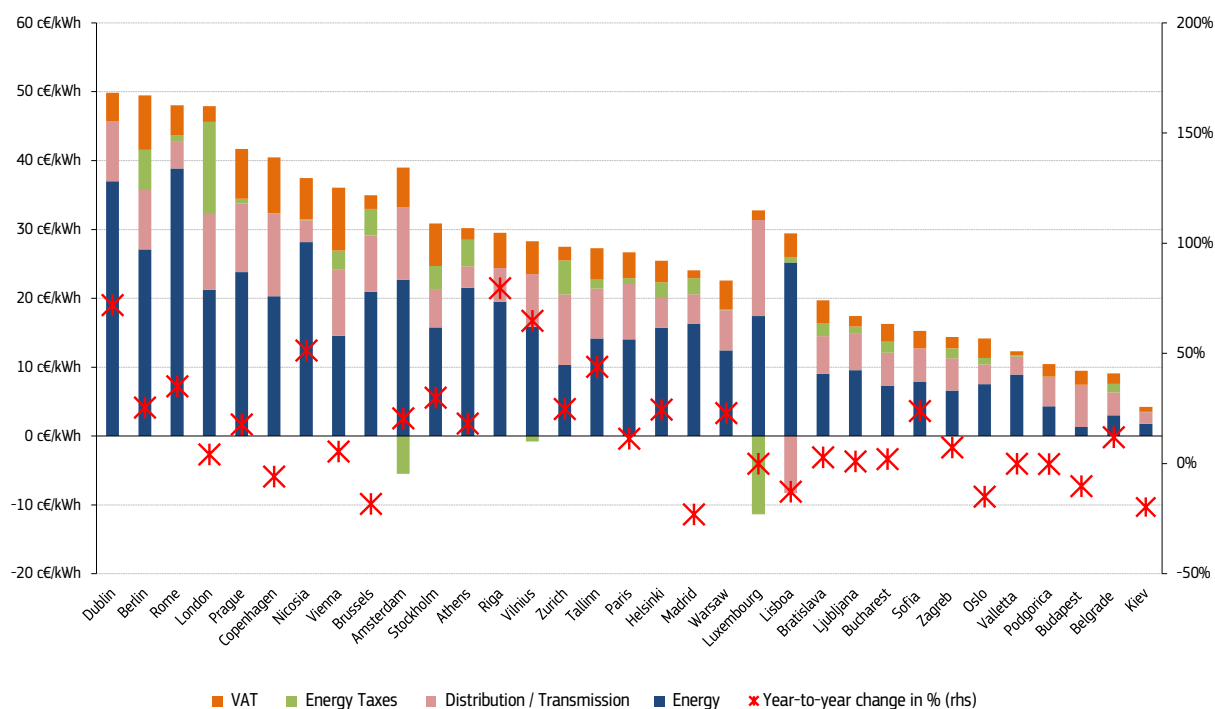
Figure 64 – Estimated industrial Electricity Prices, fourth quarter of 2022



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

- **Figure 65** shows retail electricity prices for representative household consumers in European capital cities, and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). Retail electricity prices for household costumers in EU capital cities were up by 17% in February 2023, compared to the same month in 2022. However, prices in February registered a fall for the fourth consecutive month, as a result of lower wholesale prices. The highest prices were observed in Dublin, Berlin and Rome (49.9, 49.5 and 48.0 c€/kWh, respectively). In February 2023, the energy component share now surpasses 50% of the total retail price in 21 EU capitals, up from 15 in February 2022. The energy component share is highest in Rome (81%) and Nicosia (75%). Amsterdam, Vilnius, Luxembourg, and Lisbon, represent a special case as explained below. The lowest prices among EU capitals were recorded in Budapest (9.5 c€/kWh), Valletta (12.3 c€/kWh) and Zagreb (14.4 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. A peak in retail prices for electricity consumers was registered in October 2022. Since then, retail electricity prices have been falling, despite a temporary rise in wholesale prices in December 2022, which was not able to reverse the overall decreasing trend in retail prices.
- The highest levels of the energy component in Europe were reported in Rome, Dublin and Nicosia (38.9, 37.0 and 28.1 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 (Budapest, Kyiv and Belgrade). The EU average for the energy component was 17.5 c€/kWh (up from 13.8 c€/kWh in February 2022).
- The highest network charges were recorded in Luxembourg (14.0 c€/kWh), Copenhagen (12.0 c€/kWh) and London (11.2 c€/kWh) where they accounted between 23%-30% of the total price. The lowest network fees were collected in Lisbon (-8.3 c€/kWh see explanation below), Kyiv (1.7 c€/kWh) and Valletta (2.6 c€/kWh). The EU average in the reference quarter was 6.1 c€/kWh (up from 5.3 in November 2021).
- Besides London (13.2 c€/kWh), the highest energy taxes were paid by households in Berlin (5.8 c€/kWh) and Zurich (2.0 c€/kWh). Luxembourg, Amsterdam and Vilnius stood at the other end of the range, registering negative values for taxes (see explanation below). While Riga, Sofia, Dublin and Budapest recorder practically zero energy taxes collected by local authorities. The average energy tax component stood at 0.7 c€/kWh (down from 1.5 c€/kWh in February 2022). Varied VAT rates applied to electricity, ranging from 5% in Madrid, Valletta and London to 25-20% in Vienna, Budapest and Copenhagen, also contribute to differences in household prices across Europe. Member States continue to implement measures 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 62**, and contributed to the unusual effect in which the lower the consumption, the lower the price per kWh. Similarly, consumers in Vilnius and Luxembourg receive a tax refund in their energy tax. Lisbon consumers receive a refund for the use of energy infrastructure, following a reduction in network access tariffs.

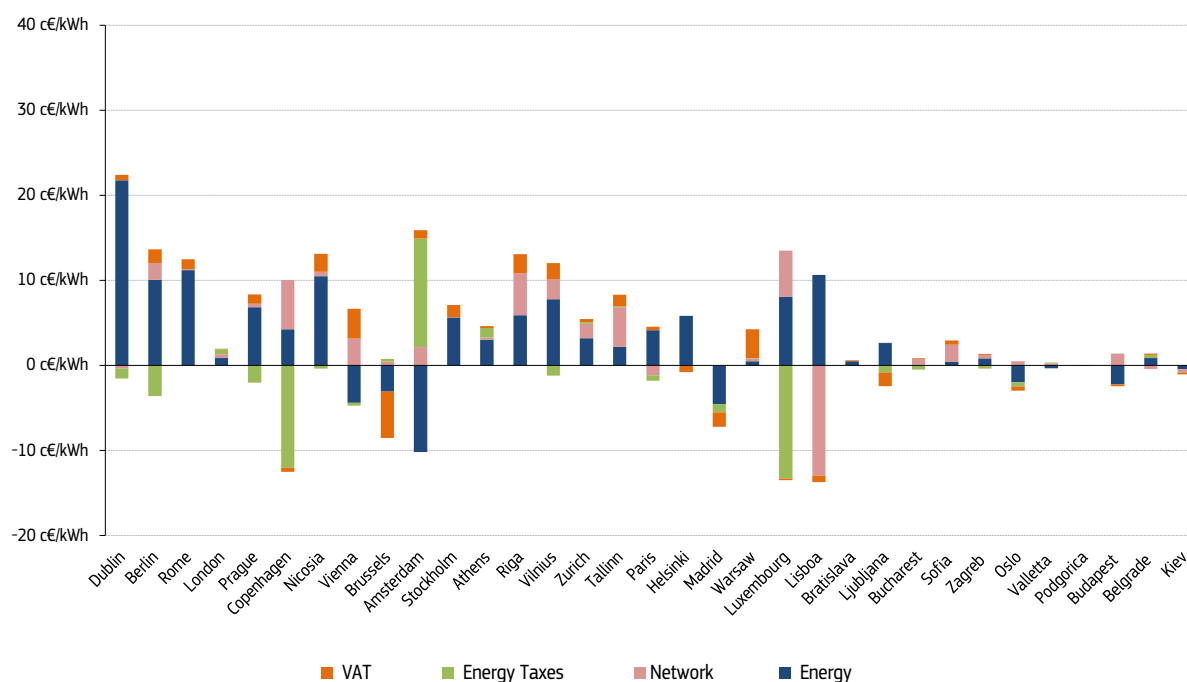
Figure 65 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, February 2023



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increase in relative terms in Europe in February 2023 was observed in Riga (+80%), Dublin (+72%) and Vilnius (+65%). As shown in **Figure 66**, rising prices were driven by higher wholesale prices than a year before in practically every EU capital. Seven of the twenty-seven EU capitals reported prices lower or unchanged, compared to the same month of the previous year, with Madrid (-23%), Brussels (-18%) and Lisbon (-13%) posting the largest relative drops. Households in these capitals benefited mainly from a reduction in the energy component.

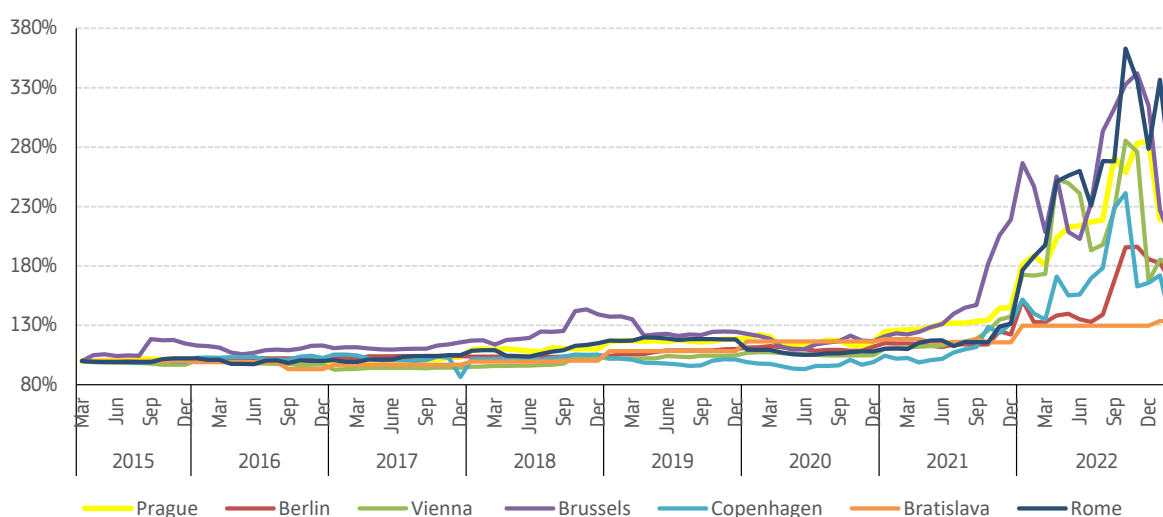
Figure 66 – Year-on-year change in electricity prices by cost components in the European capital cities comparing February 2023 with February 2022



Source: Vaasaett

- **Figure 67** compares how household retail prices in selected EU capitals changed in relative terms over the last seven years. The biggest increase in February 2022 (+254%) was registered in Rome. Prague followed with a 222% increase since February 2015, followed by Brussels (+202%) and Vienna (+182%). Retail prices for households in Copenhagen, were roughly the same as until the second half of 2021. However, prices sharply increased until October 2022, falling since then to +132% in February 2023 (compared with February 2015) marking the smallest increases of the selected capitals.

Figure 67 – Relative changes in retail electricity prices in selected EU capitals since 2015



Source: Vaasaett

Glossary

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

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

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

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

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

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

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

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

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 State 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.