



Quarterly Report

on European Electricity Markets

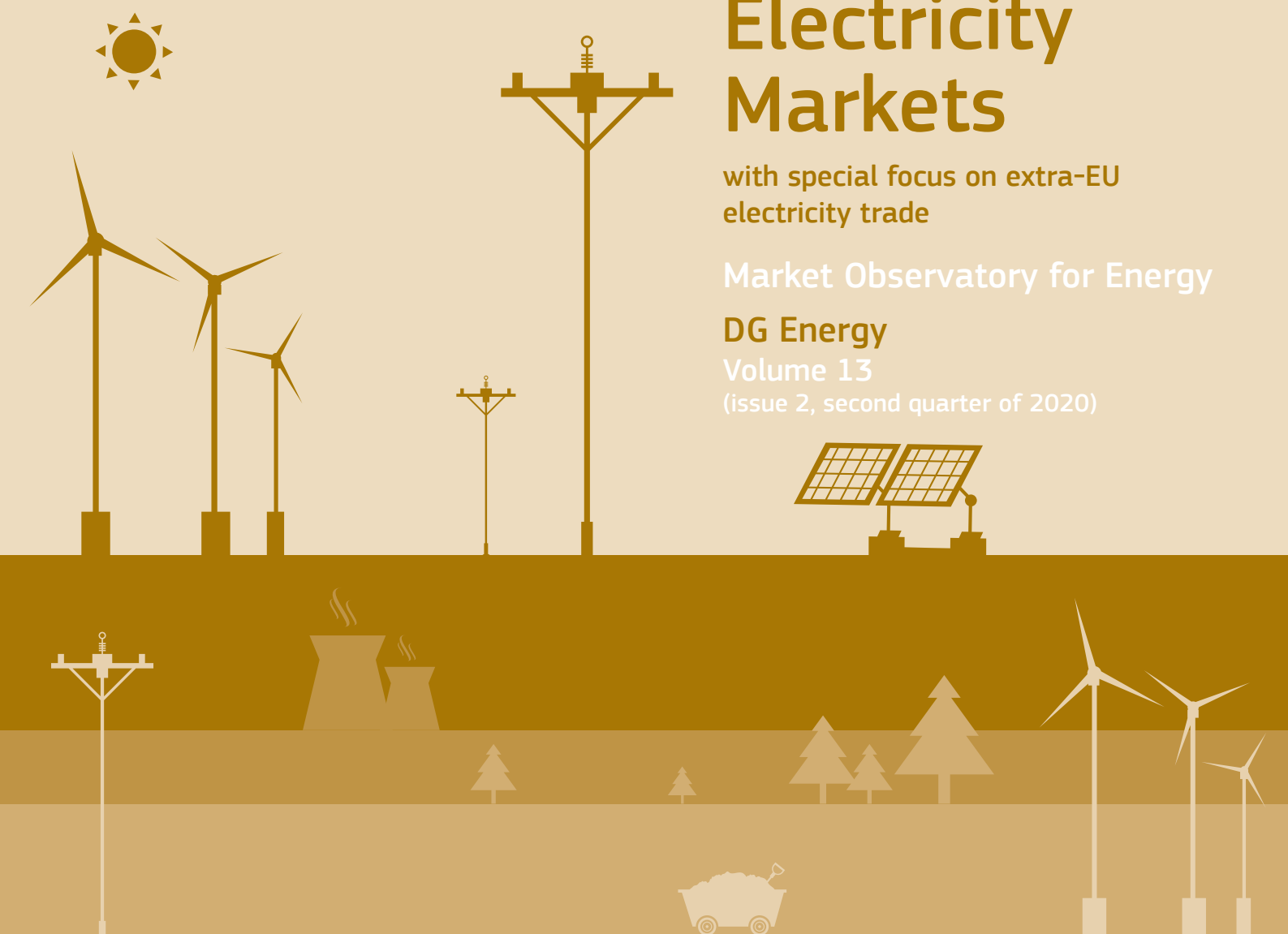
with special focus on extra-EU
electricity trade

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HIGHLIGHTS OF THE REPORT

- The coronavirus pandemic made the second quarter of 2020 an exceptionally challenging period for the electricity markets. Widespread lockdown measures suddenly reduced energy demand and radically changed the behaviour of hundreds of millions of Europeans. Electricity consumption dropped by 11% in the EU27 compared to Q2 2019, staying only slightly behind the record braking fall in economic activity in the reference quarter. Wholesale power prices decreased by 30-50% and reached levels not seen in more than a decade. Extremely low power demand coupled with changes in generation structure made the task of balancing the electricity system more difficult for grid operators. However, despite increased volatility and fluctuating liquidity, the internal market withstood the turmoil and the energy system proved its resilience in the face of the crisis. In the course of summer, electricity consumption gradually recovered and returned to normal levels only by September.
- The reference quarter witnessed dramatic changes in the structure of power generation. Fossil fuels were the main losers of the demand shock and, at the same time, were squeezed by rising solar generation which accounted for 9% of the EU27 power mix. Coal generation bore the brunt of the pressure, falling by 34% year-on-year (-32 TWh). Gas suffered losses as well (-13 TWh) despite continued coal-to-gas switching. Nuclear generation was also severely affected and fell by 17% year-on-year (-30 TWh), especially in countries with large capacities such as France and Sweden. Thanks to recovering hydro output and record high solar generation, renewable energy sources had another successful quarter, expanding by 11 TWh year-on-year and reaching a 43% share in the power mix, their highest quarterly figure to date. Thanks to their near-zero generation costs, renewables were the least affected by the pandemic and were able to capture a larger slice of a shrunken consumption pie.
- The shift away from fossil fuels caused the carbon footprint of electricity generation in the EU27 to fall by 25% year-on-year in the reference quarter, according to preliminary estimates. Counting in the 22% decrease from Q1 2020, the power sector is on track for another double-digit reduction in CO₂ emissions in 2020, after a [15% annual drop in 2019](#).
- The pandemic challenged grid operators who had to manage increased volumes of intermittent renewable energy in a low-demand environment with fewer thermal power plants online to call upon for grid stability tasks. Overall, networks coped with the situation well and proved their ability to handle high levels of renewable penetration, which at times crossed 60% in Italy, 70% in Spain, and approached 80% in Germany. However, high occurrence of negative prices, which tripled compared to Q2 2019, has accentuated the need for more storage and flexibility in the European power system in both directions. It has also intensified the search for market instruments that would put a proper value on storage and flexibility.
- As a result of falling demand, rising renewable generation and very low gas prices, day-ahead electricity prices plunged across the continent, bottoming out in April at extreme lows. A gradual recovery followed as power demand slowly rose and also thanks to the resilience of the carbon market. Nevertheless, day-ahead electricity prices were still 30% lower in July and August 2020 than in the same period last year. Forward electricity prices, which are important for consumers as most suppliers buy electricity well in advance of delivery, were less affected by the pandemic. The benchmark year-ahead contract remained 20% lower on average in the first eight months of 2020 compared to the same period of the previous year.
- In spite of the restrictions related to tackling the pandemic, demand for electrically chargeable passenger vehicles (ECVs) stayed strong between April and June. More than 129,000 new ECVs were registered in the EU27 in Q2 2020, a 53% increase compared to the same period last year. Rising interest in cleaner mobility coincided with sharply reduced sales of diesel and petrol cars and drove the market share of ECVs to record 7.2% in Q2 2020 (up from 2.4% in Q2 2019). This compares to a 4.3% ECV share in China and to 1.4% observed in the United States during the same period.
- The EU27 balance of electricity trade with countries not part of the EU ETS or its equivalents improved markedly in the first six months of 2020, ending up with a 3 TWh deficit on the back of lower imports from Russia and Ukraine. The UK, which is still part of the EU ETS and imposes an additional carbon levy of roughly 20 €/t, became EU's single most important export market in H1 2020, attracting more than 10 TWh of net imports from Belgium, France and the Netherlands.

EXECUTIVE SUMMARY

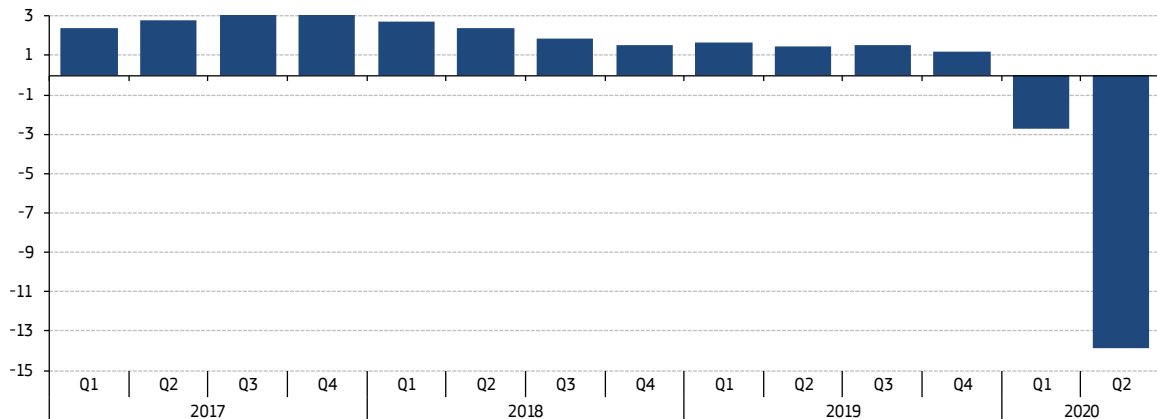
- Electricity consumption in the EU27 declined by 11% year-on-year in Q2 2020, dragged down by covid-related measures restricting social and economic activity. The demand shock was severe in all major economies, with Spain and Italy (both -14%) being hit the hardest, and France (-13%) and Germany (-11%) trailing only slightly behind. Declines were registered across all Member States. The biggest occurred in Cyprus (-17%), the smallest was recorded in Sweden (-1%).
- Prices of coal and gas in the spot market slid to their rock bottom in the course of April and May and rebounded slightly towards the second half of the reference period, as the decline in economic activity tied to lockdown restrictions eased and later gave way to a gradual and uneven recovery. Coal and gas prices on the forward curve kept declining as well, albeit at a slower pace, on the back of darkening economic outlook. Extremely low gas prices together with recovering CO2 prices cemented the advantage of gas vis-à-vis its dirtier fossil competitor in the generation mix and contributed to the continued substantial decline in coal-fired electricity generation.
- The carbon market went through volatile swings during the lockdown period as the uncertainty surrounding the effects of the coronavirus on the economy caused a temporary fall in liquidity. By the end of June, the carbon market recouped all its losses and reached even higher levels in July and August. Its resilience in the face of the pandemic contributed significantly to continually high levels of coal-to-gas switching and reduced coal-fired generation in Q2 2020. The average CO2 spot price was 21 €/t in Q2 2020 (down by 7% compared to Q1 2020). In July and August 2020, the average CO2 spot price reached 27 €/t.
- Highlighting the decline of coal in the European power sector, thermal coal imports into the EU27 plunged by 47% year-on-year to 10.6 Mt in Q2 2020, the lowest quarterly amount on record. The estimated EU27 import bill for thermal coal amounted to €0.75 billion in the reference quarter, 56% lower compared to Q2 2019 and exceeding the year-on-year decline in imported volumes due to lower prices of the commodity.
- The structure of generation in the reference quarter was influenced mainly by a large fall in consumption and rising solar generation, which combined to significantly restrict the space left for fossil fuels in the power mix. As a result, the share of electricity generated by burning coal, gas and oil declined from 35% in Q2 2019 to 31% in Q2 2020. This was the lowest quarterly figure on record. Falling power prices and rising renewable penetration seriously challenged the position of lignite-fired power plants in the merit order. Lignite-based generation fell by 35% year-on-year (or 18 TWh), while hard coal-fired generation declined by 34% year-on-year (or 14 TWh) in Q2 2020. Gas generation saw its share of the mix unchanged at 19% in the reference quarter, but lost 13 TWh in absolute terms year-on-year.
- The share of renewables (hydro, biomass, wind and solar) jumped from 37% to 43% year-on-year during Q2 2020. The main drivers behind the increased presence of renewable power were very good volumes coming from hydro sources (up 4 TWh thanks to increases in France, Sweden and on the Iberian Peninsula) and record high solar output, which rose by 21% year-on-year (or 9 TWh) thanks to increases from Germany (+2 TWh), Spain (+2 TWh), the Netherlands (+1 TWh), Italy (+1 TWh) and France (+1 TWh). Polish solar PV output surged by 160% year-on-year to 0.7 TWh in Q2 2020.
- The European Power Benchmark of nine major markets averaged 19 €/MWh in the reference quarter, down 52% compared to Q2 2019. The cheapest baseload power prices were observed in the Nordic region which benefited from record high hydro generation from reservoirs overflowing with melting snow. Even though wholesale prices were falling across different regional markets in Q2 2020, divergence levels were high. This was due to the fact that the decline in prices was uneven and its extent was influenced by several factors such as the severity of lockdown measures, weather conditions and the level of renewable penetration. For instance, average monthly Nord Pool system prices moved between 3 and 8 €/MWh in the reference quarter, while they were three to four times higher in Greece.
- At 648, the number of hours with negative wholesale prices in Q2 2020 was almost three times larger in observed bidding zones than in the previous Q2. The highest numbers of falls into negative territory were concentrated into April and May when the effect of lockdown restrictions was weighing heavily on power demand, which in turn reduced manoeuvring space for conventional generators.
- Average retail prices continued to decrease across all consumer groups in Q2 2020. Falling European wholesale prices witnessed over the last 18 months have started to pass through to retail markets. Retail prices for households moved increasingly in the same direction, reaching their highest level of convergence on record in June.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the economic impact of the containment measures imposed towards the end of Q1 2020 to combat the spreading of the coronavirus was even more pronounced in Q2 2020. According to an estimate published by Eurostat in September, seasonally adjusted GDP in the EU27 shrank by 13.9% year-on-year between April and June 2020. This was by far the sharpest decline since the time series began in 1995 and demonstrates the scale of economic and social disruption brought on by the pandemic. A contraction of output was observed in each Member State. The highest declines were reported in Spain, France and Italy.

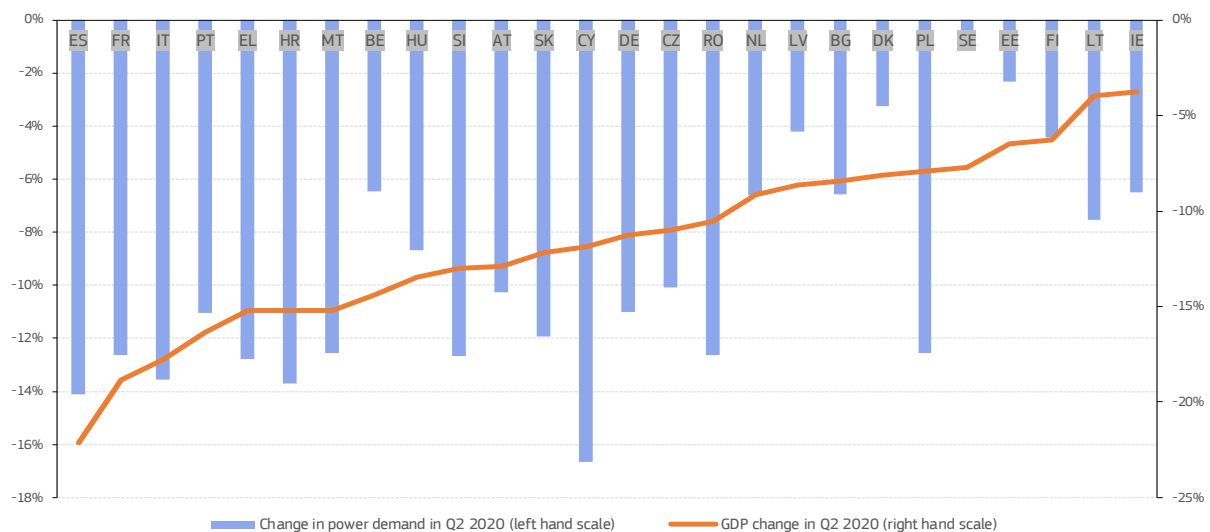
Figure 1 – EU27 GDP annual change (%)



Source: Eurostat

- According to Eurostat figures, the consumption of electricity in the EU27 fell by 11% year-on-year in Q2 2020, driven down by covid-related restrictions on economic and social activity. As large populations spent more time at home household electricity consumption increased, but this could not compensate for a considerable fall in the demand from the commercial and industrial sectors. As demonstrated by **Figure 2**, the largest falls in power demand were generally observed in Member States undergoing the steepest GDP contractions and vice versa. However, there were several exceptions such as Cyprus, Romania and Poland, where power consumption decreased relatively sharply compared to the overall performance of the economy. Belgium and Sweden, on the other hand, saw relatively mild reactions of power consumption compared to the scale of their recession. This points to different roles electricity supply plays in the most affected sectors of each Member State and also to varied forms of response to the pandemic. 15 Member States experienced a year-on-year fall in power consumption of 10% or more in Q2 2020, which is unprecedented in modern times.

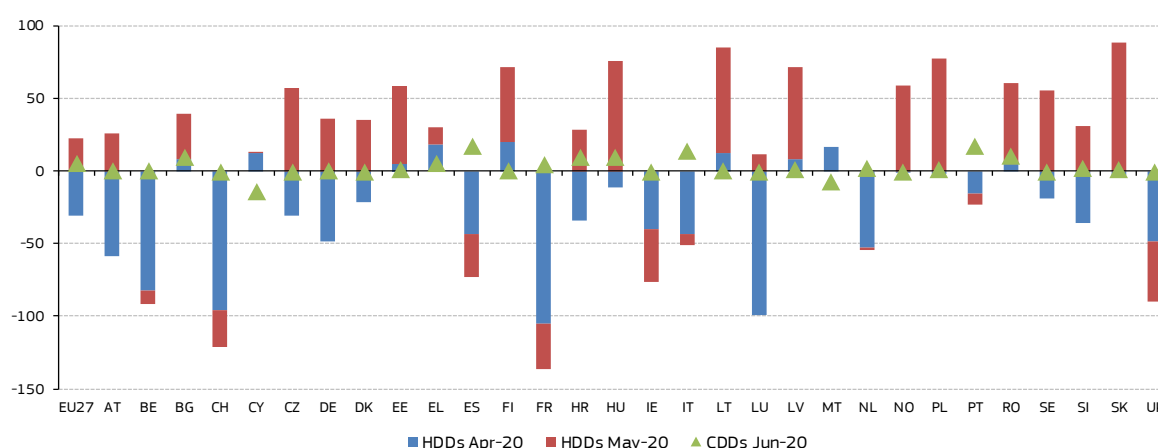
Figure 2 – Annual change in power demand and GDP in Q2 2020



Source: Eurostat

- **Figure 3** illustrates the monthly deviation of actual Heating Degree Days (HDDs for April and May) and Cooling Degree Days (for June) from the long-term average (a period between 1978 and 2018) in Q2 2020. EU-wide, the first two months of the reference quarter had 8 HDDs below average, which means that temperatures did not move far off from their usual levels. A relatively warmer April was to a large extent compensated by a colder May. Notable exceptions included France where higher-than-usual temperatures were recorded in both months. This further dampened electricity demand, which was already under pressure from lockdown measures. Power consumption in France is especially sensitive to temperature deviations, as a large part of local household heating is dependent on electricity. Only negligible differences in temperatures compared to long-term averages were recorded in June. The effect on cooling demand was thus minimal.

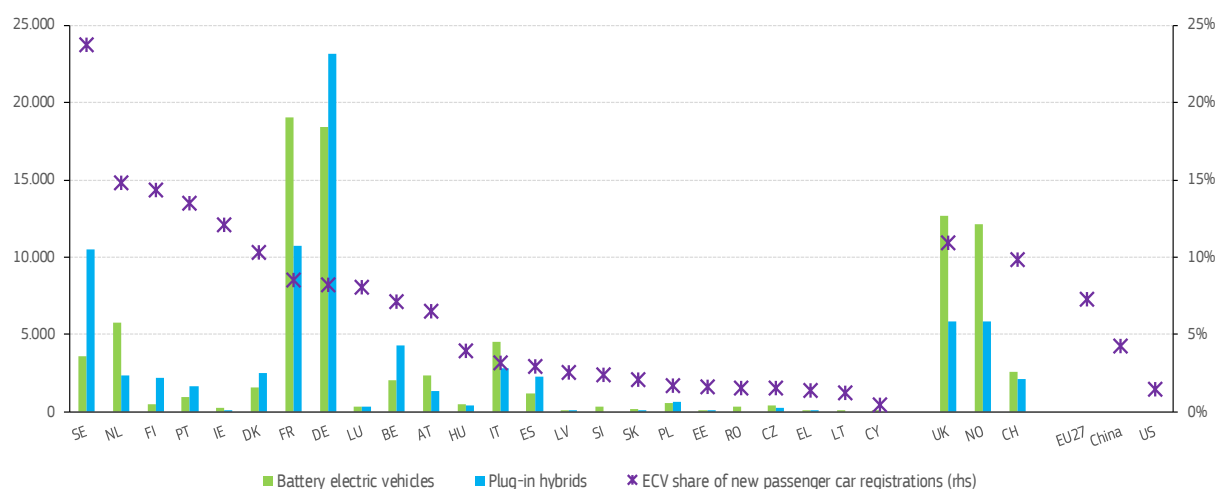
Figure 3 - Deviation of actual heating and cooling days from the long-term average in April-June 2020



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

- **Figure 4** testifies to the robustness of the demand for electrically chargeable passenger vehicles (ECVs) in European countries throughout the most critical months of the pandemic, and also to the effectiveness of government support policies aimed at incentivizing ECV purchases. More than 129,000 new ECVs were registered in the EU27 in Q2 2020. While this was 23% less than in Q1 2020 when sales were not so much affected by covid-related restrictions, it still represents a 53% increase compared to the same period last year. The good performance was mainly driven by the plug-in hybrid segment (+134% year-on-year to 66,000), while demand for battery electric vehicles grew at a more moderate clip (+13% year-on-year to 63,000). Increased interest in cleaner mobility coincided with sharply reduced sales of diesel and petrol cars and drove the market share of ECVs to record 7.2% in Q2 2020 (up from 2.4% in Q2 2019). This compares to a 4.3% ECV share in China and to 1.4% registered in the United States. The highest ECV penetration was observed in Sweden where one in four new passenger cars sold could be plugged. The Netherlands came in second with a 15% ECV share, followed by Finland, Portugal and Ireland. Germany retained the position of the largest individual market in absolute terms with more than 40,000 newly registered ECVs. More than half of Member States offer a direct purchase incentive for ECVs, usually in the form of grants, subsidies, tax reductions, scrappage schemes or income tax credits.

Figure 4 – Electrically chargeable passenger vehicle (ECV) registrations in selected countries in Q2 2020



Source: ACEA, CPCA, BloombergNEF

- ECV users' preferences for charging location depends on a range of factors, such as access to a driveway at home, availability of public charging infrastructure, pricing applied by operators or driving habits. Charging at home is the most popular option as it is often most convenient and cheapest, with prices essentially mirroring regular electricity tariffs for households. A survey of 12 European countries revealed that off-peak tariffs are available in most of them, although the uptake tends to be low in some cases. As of August 2020, dedicated ECV tariffs were available only in Spain, France and the UK, which shows a large opportunity to cater to the needs of a rapidly growing pool of ECV users. In terms of the price differential between the regular tariff and the off-peak tariff, a substantial variation across markets can be observed. As shown in **Figure 5**, off-peak prices could be as much as 40% lower compared to average prices, offering substantial savings and an incentive to adapt charging behaviour. Countries with the highest difference include Australia, France, Spain and the UK. Fully charging an average-size battery with a 350km range in France in off-peak hours costs approximately 6 EUR, which compares with roughly 19 EUR in the fuel bill for the same range in an average conventional vehicle.

Figure 5 – Prices for charging ECVs at home in selected countries



Source: Trinomics (Study on energy prices, costs and their impact on industry and households, 2020, page 87)

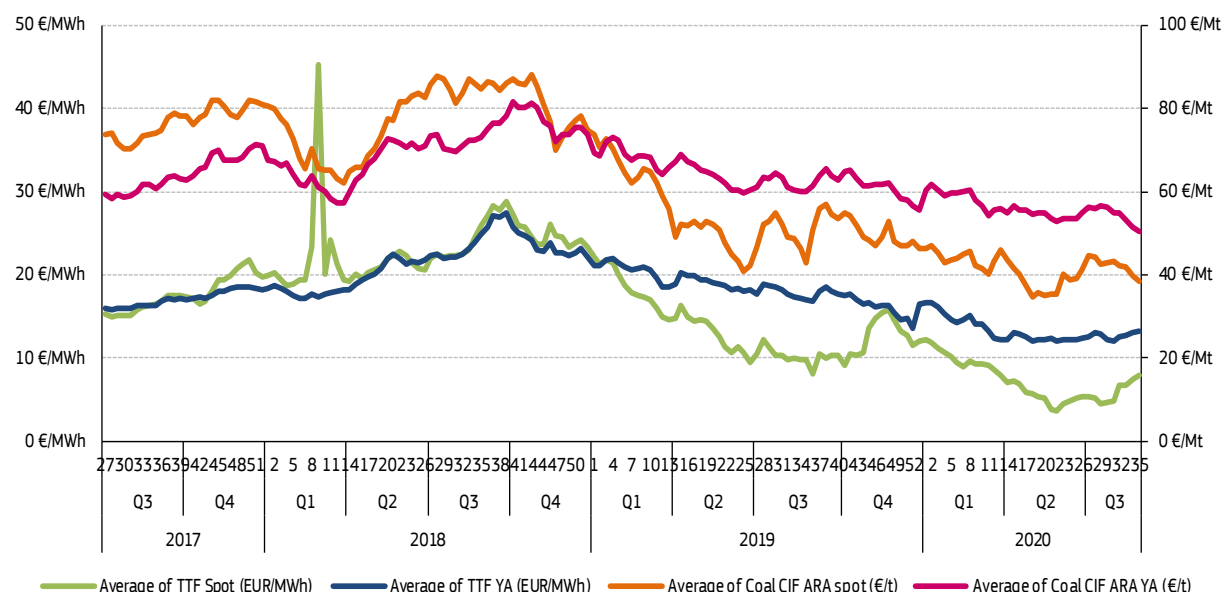
1.2 Supply side factors

- **Figure 6** reports on the developments in European coal and gas prices. Prices of both commodities in the spot market slid to their rock bottom in the course of April and May and rebounded slightly towards the second half of the reference period, as the decline in economic activity tied to lockdown restrictions eased and later gave way to a gradual and uneven recovery. Prices on the forward curve kept declining as well, albeit at a slower pace, on the back of darkening economic outlook. Extremely low gas prices together with recovering CO2 prices cemented the advantage of gas vis-à-vis its dirtier competitor in the generation mix and contributed to the continued substantial decline in coal-fired electricity generation.
- Spot gas prices (represented by the TTF day-ahead contract) were sliding continuously during the first half of the reference period, on the back of very weak demand, healthy supply and high storage levels. An all-time low of just 3.1 €/MWh was reached in on 21 May, beating a previous record low of 4.5 €/MWh from October 2006. A turnaround came just as traders started to consider the possibility of zero or negative prices as had happened in the oil market. A drop in LNG deliveries, rising gas-fired electricity generation and a spell of colder temperatures tightened the supply-demand balance and propped up prices which were hovering close to 5 €/MWh for the rest of the reference quarter. Overall, the average quarterly TTF spot price reached 5.4 €/MWh in Q2 2020 (down 45% compared to Q1 2020 and down 59% compared to Q2 2019).¹ Spot gas prices continued to gain ground in July and August amid recovering industrial demand.

¹ For more information on gas markets see Quarterly Report on the European Gas Markets, Vol. 14, Issue 2.

- Thermal coal spot prices, represented by the CIF ARA contract, were under heavy pressure of cheap gas, rising solar generation and extremely weak electricity consumption during much of Q2 2020. Stockpiles at main port terminals remained high due to low demand from generators, especially in Germany and the Netherlands. After prices dropped to a 13-year low in mid-May, a rebound took place on the back of supply disruptions at a major Russian coal port and rising spot gas prices. The average quarterly CIF ARA spot price was assessed at 38.3 €/t in Q2 2020 (down 13% compared to Q1 2020, and down 21% compared to Q2 2019). Spot coal prices remained low in July and August as coal firing at power plants continued to be largely uneconomical.
- Year-ahead gas prices remained under pressure of high LNG delivery prospects, weak commodity prices and high storage levels in Q2 2020 and, at 12.3 €/MWh, were trading on average 14% lower than in the previous quarter. Meanwhile, year-ahead CIF ARA contracts also remained depressed, averaging 54.6 €/t (-7% quarter-to-quarter).

Figure 6 – Weekly evolution of spot and year-ahead coal and gas prices



Source: S&P Global Platts

- After a precipitous fall at beginning of the lockdown period in March, the market for emission allowances, shown in **Figure 7**, recovered strongly during Q2 2020, as short-term demand weakness gave way to longer-term supporting factors. By the end of June, the carbon market recouped all of the losses suffered during the most acute phase of the pandemic, and reached even higher levels in July and August. The resilience of the carbon market in the face of the pandemic contributed significantly to continually high levels of coal-to-gas switching and reduced coal-fired generation in Q2 2020.
- CO2 prices climbed quickly above 20 €/t at the beginning of April as governments and central banks sprang into action and provided strong fiscal and monetary stimulus to the shell-shocked economy. Even though the demand from power generators and industrial emitters was expected to decline substantially due to low production volumes, buyers appeared to be keen to make the best use of a period of relatively low prices, especially in view of a possible firming of 2030 climate ambitions at EU level. Prices declined slightly in the second part of April, as the annual compliance deadline to surrender allowances to cover 2019 emissions passed, but moved decidedly upwards afterwards.
- With energy demand depending to a large extent on a recovery from the pandemic and lifting of lockdown restrictions, carbon prices have taken some direction also from the wider and more established energy and financial markets in Q2 2020. All in all, the average CO2 spot price in Q2 2020 fell by 7% compared to Q1 2020, a third quarter-to-quarter decline in a row. At 21 €/t, the average price of one allowance in the reference quarter was also 17% lower compared to the same quarter a year ago. In July and August 2020, the average CO2 spot price reached 27 €/t.

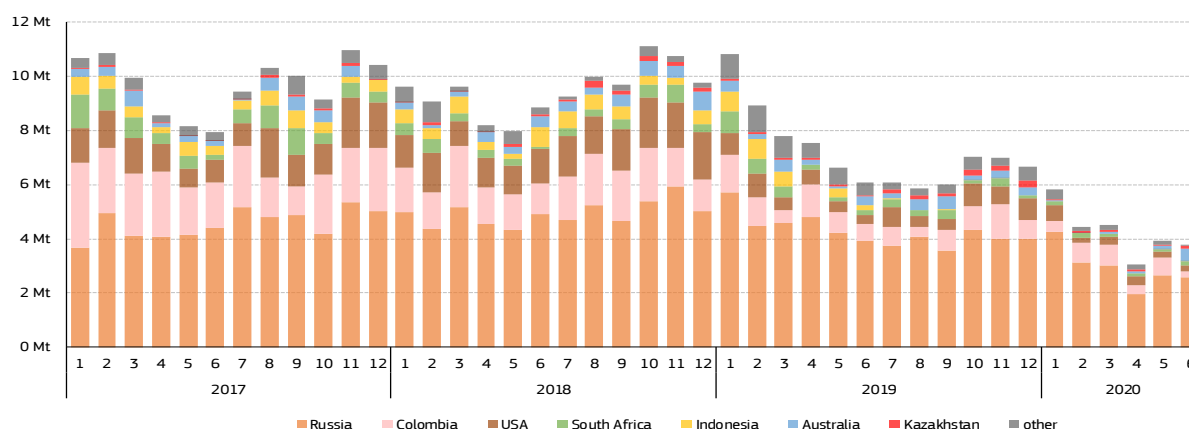
Figure 7 – Evolution of emission allowance spot prices from 2018



Source: S&P Global Platts

- **Figure 8** shows that thermal coal imports into the EU27 plunged by 47% year-on-year to 10.6 Mt in Q2 2020, the lowest quarterly amount on record. The fall was especially severe in April, at the height of covid-related restrictions on economic activity which drastically reduced electricity demand and coal burn (see **Figure 17**). The estimated EU27 import bill for thermal coal amounted to €0.75 billion in the reference period, 56% lower compared to Q2 2019 and exceeding the year-on-year decline in imported volumes due to lower prices of the commodity.
- The largest part of extra-EU thermal coal imports came from Russia which accounted for 67% of the total in the reference quarter. Russian traders dominate the rapidly shrinking European thermal coal market, as most of their rivals find it difficult to compete in the tough low-price, low-demand environment. Colombia saw its market share shrinking to 11% from 13% in the previous quarter. The position of the United States remained unchanged with a 7% share. Australian importers increased their share from 1% in Q1 2020 to 7% in Q2 2020 due to a large increase in deliveries in June. Imports from other trading partners were insignificant.
- Thermal coal shipments declined in all major EU importers in Q2 2020. Deliveries to German, Belgian and Dutch terminals (calculated together as part of one supply chain feeding German and Dutch power plants) fell by 54% year-on-year to 4.5 Mt amid low demand in Western Europe. Polish terminals saw shipments declining by 19% year-on-year in Q2 2020 to 2.0 Mt, in line with the 20% fall in hard coal generation during the same period. In the rest of the major markets, low coal generation significantly reduced imports, with Italy registering 1.4 Mt of deliveries (-25% year-on-year), Spain 0.8 Mt (-58% year-on-year) and France 0.8 Mt (-40% year-on-year). Shipments to Portugal ceased completely in April and May as generation in local coal power plants dropped by 98% in the reference quarter.

Figure 8 – Extra-EU thermal coal import sources and monthly imported quantities in the EU27



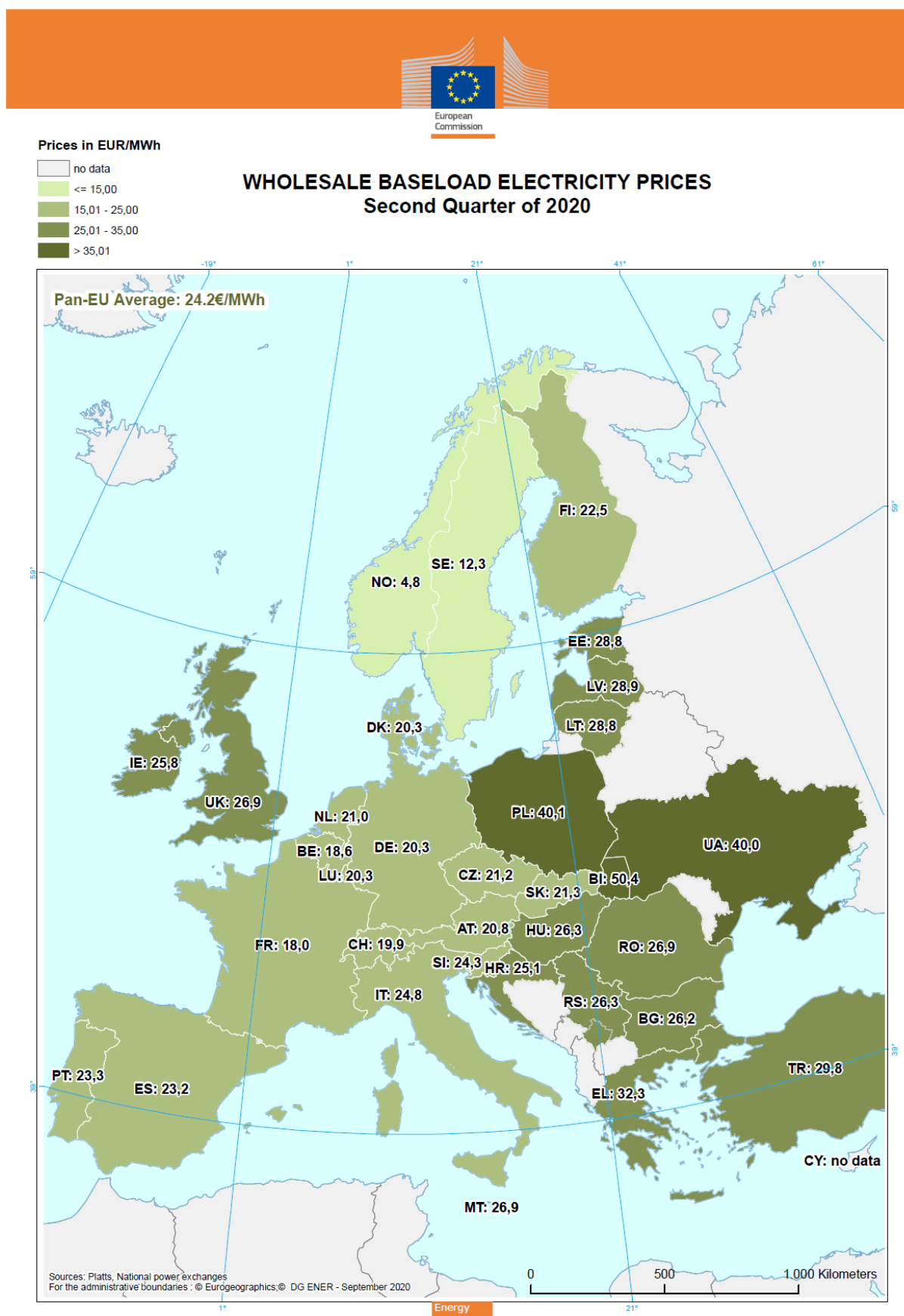
Source: Eurostat

2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q2 2020. All markets experienced substantial price drops related to lockdown measures which reduced electricity demand (see **Figure 2**). The extent of these decreases, however, varied according to local weather conditions, renewable penetration and available cross-border capacities. The cheapest baseload power prices were observed in the Nordic region where record breaking snowfall in winter forced increased hydro generation to make room for snowmelt. This was true especially for Norway where prices fell to lower single digits. Western European markets also experienced very low prices on the back of high solar PV generation and low demand. Average baseload prices in nearly all markets sank under 30 €/MWh. Greece became the second most expensive market with an average baseload price of 32 €/MWh, which was still 50% lower compared to the same period last year. Poland, on the other hand, experienced the lowest year-on-year decline in the quarterly baseload average price (-29% to 40 €/MWh) as its limited interconnection capacities and greater reliance on costly coal generation propelled it to be by far the most expensive market in the EU27 in Q2 2020.
- The pan-EU average of day-ahead baseload prices reached 24 €/MWh in the reference quarter, down 44% in a year-on-year comparison. Compared to Q1 2020, the quarterly average fell by 29% on the back of weak demand and increased solar generation.
- In an annual comparison, all markets reported lower prices in Q2 2020. The biggest year-on-year decreases happened in Norway (-87%), Sweden (-63%) and Malta (-58 %).

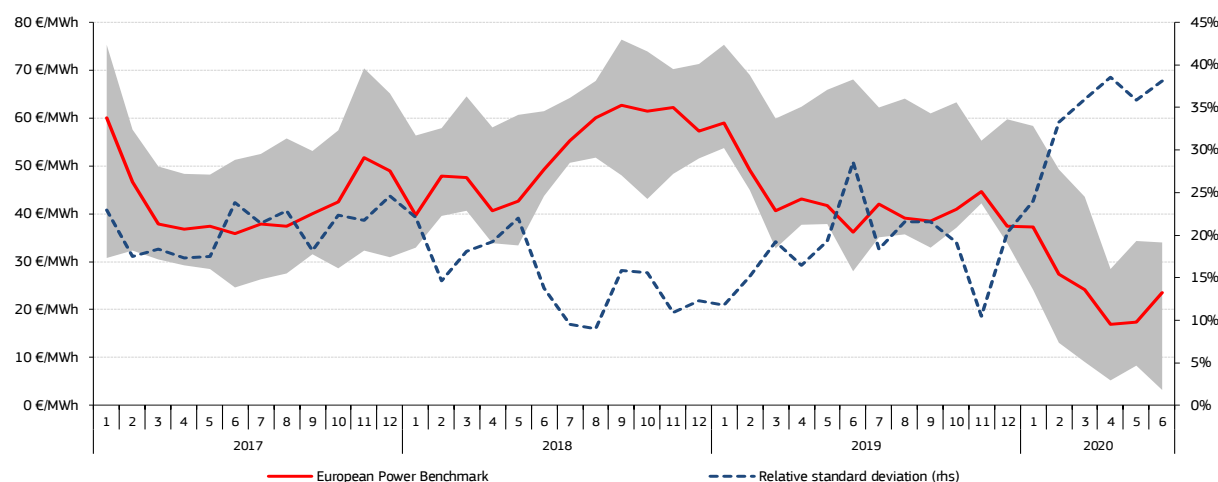
Figure 9 – Comparison of average wholesale baseload electricity prices, second quarter of 2020



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 10** shows the European Power Benchmark and, as the two lines of boundary of the shaded area, the lowest and the highest regional prices in Europe, as well as the relative standard deviation of the regional prices. Both the shaded band and the relative standard deviation metric show that divergence levels, which increased considerably at the beginning of 2020, remained elevated in the course of Q2 2020, even though wholesale prices were falling across the continent. This was due to the fact that the decline in prices was uneven and its extent was influenced by several factors such as the severity of lockdown measures, weather conditions and the level of renewable penetration. For instance, average monthly Nord Pool system prices moved between 3 and 8 €/MWh in the reference quarter, while they were three to four times higher in Greece. As a result, the relative standard deviation figure in wholesale markets under observation reached its highest level in five years in Q2 2020. Meanwhile, the European Power Benchmark fell to its lowest level on record and averaged 19 €/MWh in Q2 2020.

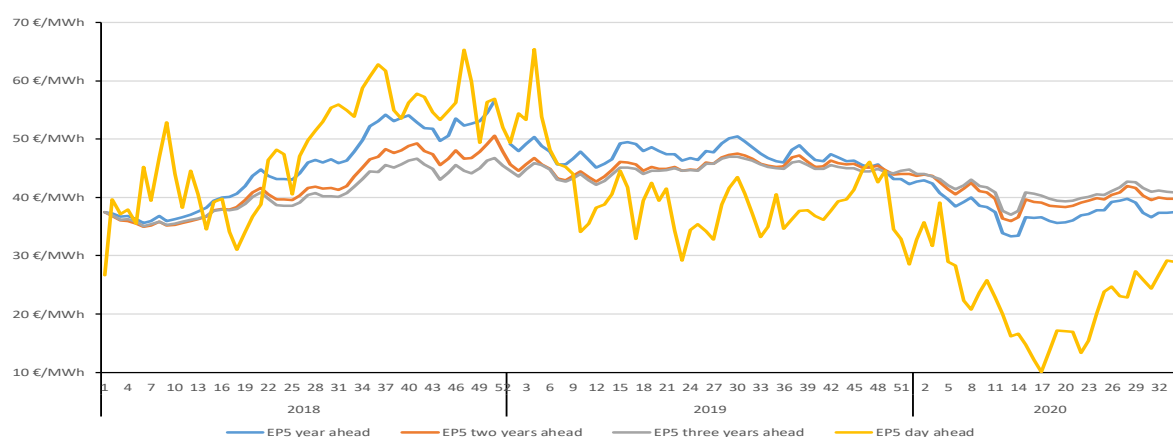
Figure 10 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



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

- In order to obtain a comprehensive picture of how European wholesale electricity prices have developed, a consumption-weighted baseload benchmark (EPS) of 5 advanced markets offering a 3-year visibility into the future was created and compared to a day-ahead (spot) equivalent. As shown in **Figure 11**, the spot market entered a period of high volatility in the wake of the pandemic. Widespread lockdown measures and restrictions on economic activity significantly reduced power consumption (see **Figure 2**), driving down spot prices. Compounding this in April was sunny weather which boosted renewable penetration in the grid and put further pressure on spot prices. The trough came around Easter when the severity of lockdowns was at its peak and spot prices hit their lowest level in more than a decade and in some markets the lowest level on record. Spot prices have been recovering since then as power demand began to return to normal levels, and also thanks to the resilience of the carbon market and rising gas prices. Nevertheless, spot electricity prices were still 30% lower in July and August 2020 than in the same period last year. Forward electricity prices, which are important for consumers as most suppliers buy electricity well in advance of delivery, were less affected by the pandemic. The year-ahead contract remained 20% lower on average in the first eight months of 2020 compared to the same period of the previous year.

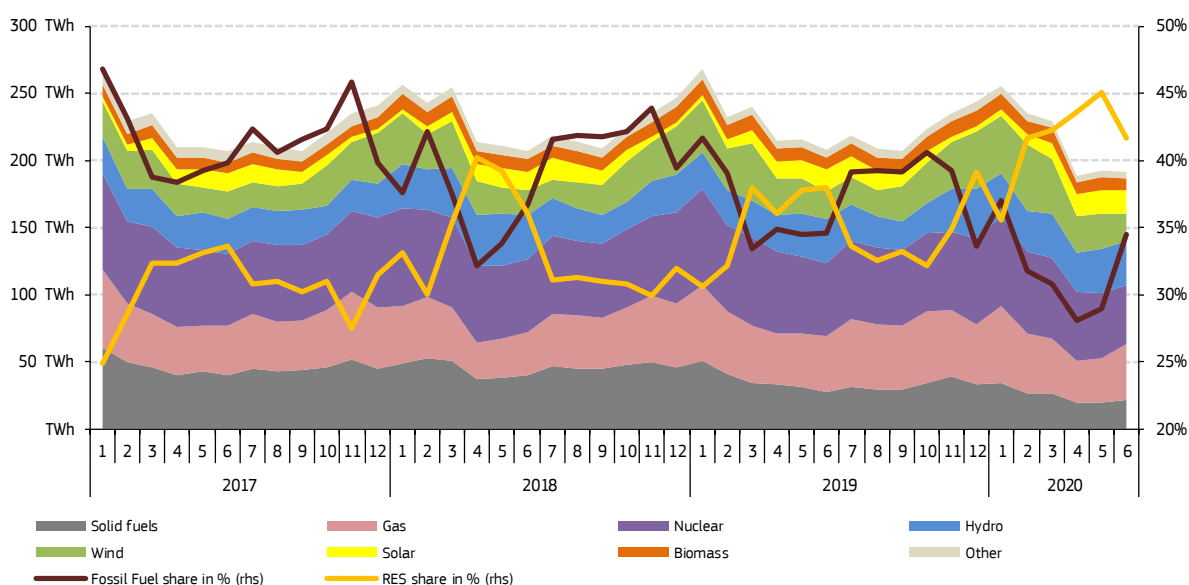
Figure 11 – Weekly spot and forward baseload prices – weighted average of 5 European markets



Source: Platts.

- **Figure 12** shows the evolution of the electricity mix in the EU27. The structure of generation in the reference quarter was heavily influenced by lockdown measures which significantly reduced power demand and, consequently, generation by conventional power plants, which have higher operational costs than their renewable peers. As a result, the share of electricity generated by burning coal, gas and oil declined from 35% in Q2 2019 to 31% in Q2 2020. This was the lowest quarterly figure on record. Nuclear generation was also measurably affected by the demand shock and its share fell to 25% in the reference quarter (from 27% in Q2 2019). On the other hand, the share of renewables (hydro, biomass, wind and solar) jumped from 37% to 43% during the same time, as green sources, boosted by rising solar generation, managed to take a larger portion of the shrunken consumption pie.
- Within the fossil fuels complex, both coal and gas suffered losses compared to Q2 2019 as sharply falling demand affected markets with a heavy presence of either fuel. Less CO₂-intensive gas generation saw its share of the mix unchanged at 19% in the reference quarter as its absolute loss of 13 TWh year-on-year copied the general decline in consumption. Solid fuels went through a sharp drop both in relative and absolute terms. Their share in the mix was reduced to 11% in the reference quarter (from 15% in Q2 2019), which translated into 32 TWh less electricity produced by burning coal and lignite in a year-on-year comparison. Renewables, in contrast, generated 11 TWh of electricity more in the reference quarter compared to the same quarter a year before.
- Between hard coal and lignite (the distinction between them is not visible in **Figure 12**), the latter tends to be more resilient in the face of changing market environment, as lignite generation traditionally displays more competitive marginal costs per unit of energy produced. This stems mainly from low production costs of the input fuel, which is usually mined in close proximity to power plants that use it. On the other hand, 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 on average 17% cheaper in Q2 2020 compared to Q2 2019. Nevertheless, low demand, falling power prices and rising renewable penetration seriously challenged the position of lignite-fired power plants in the merit order. As a result, lignite-based generation in Q2 2020 fell by 35% year-on-year (or 18 TWh), while coal-fired generation plunged by 34% year-on-year (or 14 TWh). Thus, the combined share of coal and lignite in the EU27 power mix in Q2 2020 fell below that of onshore wind.

Figure 12 – Monthly electricity generation mix in the EU27

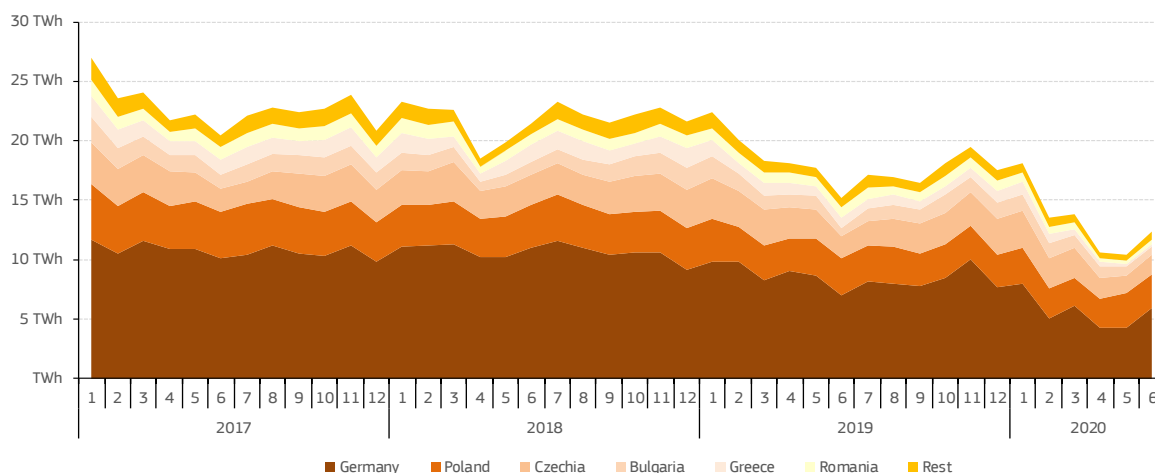


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation. Fossil fuel share calculation covers power generation from coal, lignite, gas and oil.

- The decreasing trend of electricity generation from lignite-fired power plants in the EU27 is displayed in **Figure 13**. The total monthly output dropped below 11 TWh for the first time in April and May 2020 as low demand and more economical alternatives pushed the dirtiest fuel out of the grid. In Germany, home to the largest fleet of lignite units, lignite generation fell by 41% year-on-year in Q2 2020, displaced by extremely cheap gas and rising solar penetration. In fact, the prevailing constellation of fuel and carbon costs made the most efficient lignite unit less profitable than the least efficient gas power plant. Additionally, standard clean spread models show German lignite power plants to be unprofitable on the day-ahead market since February 2020. In Poland, lignite-fired units displayed much greater resilience due to a lower number of alternative sources. Thus, lignite generation fell only by 9% year-on-year in Q2 2020, which was one of the main factors behind relatively high wholesale electricity prices in Poland in the reference period (despite a relatively high drop in consumption). The output of the Czech lignite fleet decreased by 30% year-on-year in Q2 2020 on the back of low demand. The three Member States ac-

counted for 83% of the total lignite-based generation in the EU27 in Q2 2020. The largest fall in lignite generation (-70% year-on-year) was observed in Greece where gas and onshore wind proved to be more competitive substitutes.

Figure 13 – Monthly generation of lignite power plants in the EU27

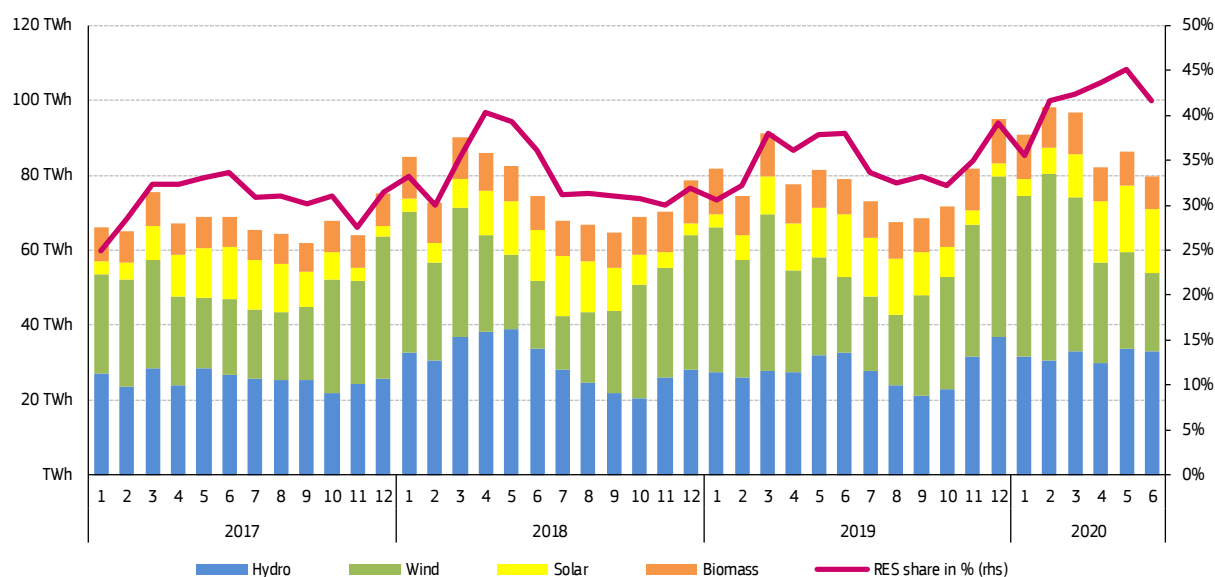


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 14** depicts the evolution of monthly renewable generation in the EU27, alongside its share in the electricity generation mix. Renewable energy sources reached another milestone in Q2 2020 as their quarterly share in the mix rose to 43%, the highest figure so far. This was more than six percentage points above the same quarter a year ago. The covid-related demand shock and a 4% year-on-year rise in renewable generation contributed to the unprecedented surge in renewable penetration. On several days in April, May and June, renewable energy covered more than half of EU's electricity demand. Interestingly, these were not exclusively Sundays when consumption usually reaches its weekly low point.
- Apart from lower demand, the main drivers behind the increased presence of renewable power in the European mix in the reference quarter were good output volumes coming from hydro sources (up 4 TWh thanks mainly to increases in France, Italy and on the Iberian Peninsula which more than compensated for dry conditions in the Balkans) and record high solar generation which increased by 21% year-on-year (up 9 TWh). Wind generation, which tends to taper off in the summer period, stayed unchanged in absolute terms in Q2 2020 compared to a year before, taking a 13% share in the power mix. Biomass-based generation declined by 9% (or 3 TWh) year-on-year, in line with the general decrease in demand.
- Thanks to good weather conditions and significant capacity expansion, solar PV performed impressively in Q2 2020 and with a 9% share in the power mix became the third biggest contributor to the total renewable output (after hydro and wind). The largest increases in solar PV generation came from Germany (+2 TWh), Spain (+2 TWh), the Netherlands (+1 TWh), Italy (+1 TWh) and France (+1 TWh). Polish solar PV output jumped by 160% year-on-year to 0.7 TWh in Q2 2020. Generation from solar panels in Hungary doubled to 0.8 TWh in the same period.
- At 43%, the combined share of hydro, biomass, wind and solar sources in the EU27 electricity generation in Q2 2020 was higher than in other major economies. The share of renewables in the US power mix in the reference quarter stood at 24%, whereas in China and India renewable energy constituted 24% and 28% of their respective total power generation during the same quarter.²

² Calculations based on the data from Energy Information Administration in the US, China Electricity Council and Central Electricity Authority in India. The Chinese figure does not include biomass.

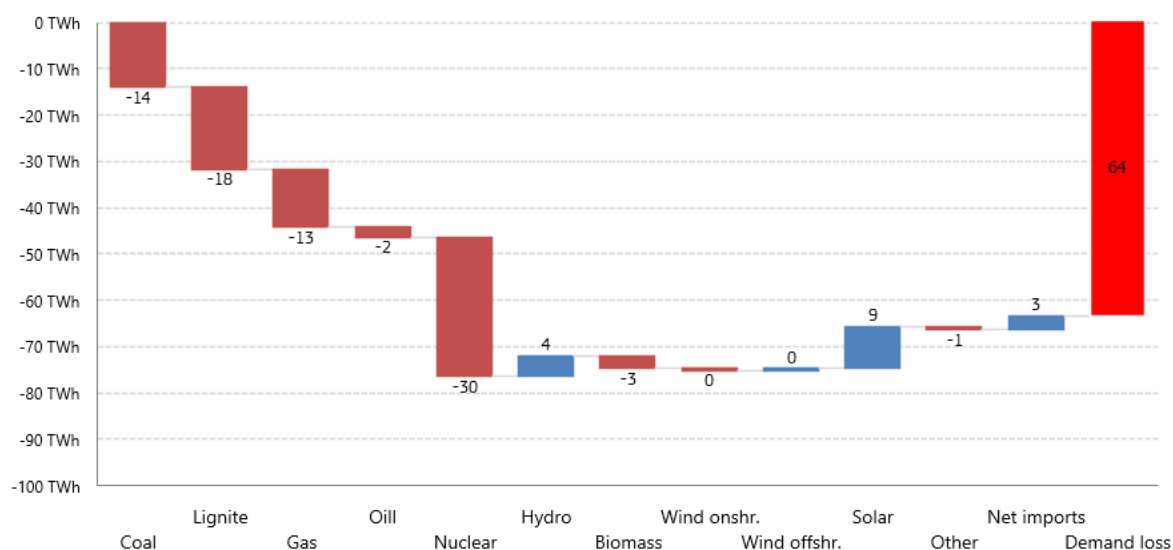
Figure 14 – Monthly renewable generation in the EU27 and the share of renewables in the power mix



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

- **Figure 15** visualises changes in the EU27 electricity generation balance in the reference quarter compared to the same quarter a year before. The space for conventional power plants' running hours was significantly restricted by two factors. First, lockdown measures dealt a substantial blow to power demand, reducing it by 64 TWh. Second, rising renewable generation removed further 11 TWh. As a result, the fossil fuels sector suffered a combined loss of 46 TWh, while nuclear generation declined by 30 TWh (mainly on account of lower volumes in France, Sweden and Belgium). Net imports from third countries increased by 3 TWh mainly due to high inflows from Norway. Based on preliminary estimates, the carbon footprint of the power sector in the EU27 dropped by 25% year-on-year in Q2 2020 due to the much lower burning of fossil fuels.

Figure 15 – Changes in power generation in the EU27 between Q2 2019 and Q2 2020

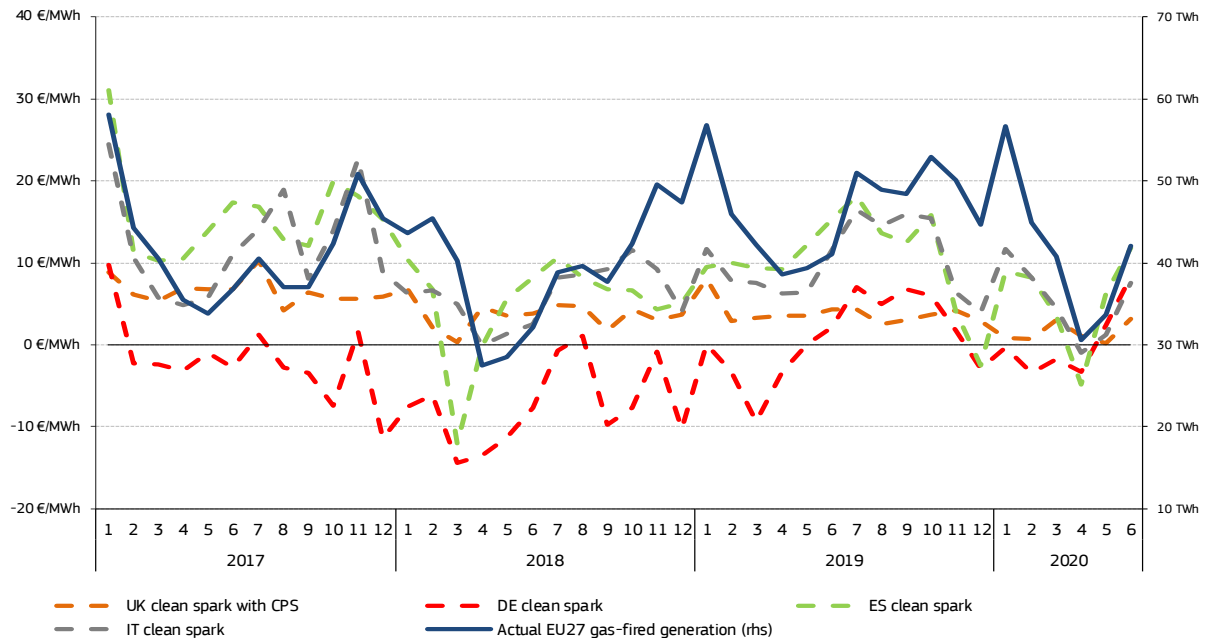


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation

- The following two figures report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at their clean spread indicators. Gas retained its competitive edge over coal in Q2 2020 on the back of the resilience of the carbon market and extremely low gas prices.
- As shown in **Figure 16**, the profitability of gas firing for electricity generation was on a rising trajectory during Q2 2020 in all four markets under observation. [Clean spark spreads](#) reached their trough and were mostly negative in April when tumbling demand pressed power prices to record lows. But gas margins gradually recovered

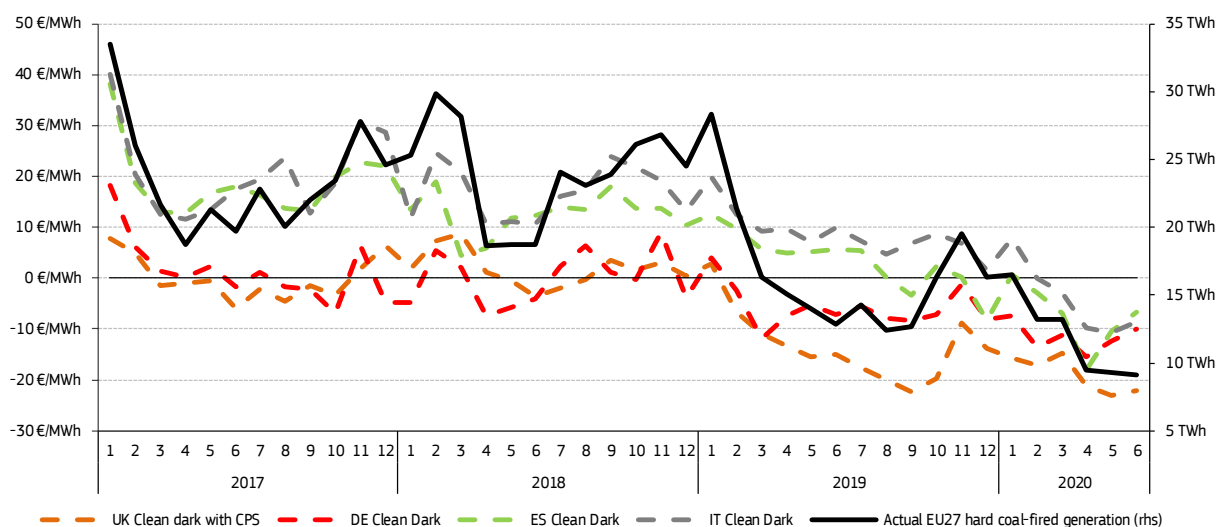
amid rising wholesale power prices and falling gas prices. By the end of the reference quarter, clean spark spreads were in double-digit territory in Spain and around 8 €/MWh in Germany and Italy. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU27 gas generation reached 106 TWh in the reference quarter, compared to 119 TWh in Q2 2019. The outlook for gas remains positive. As of September 2020, clean spark spreads in Germany were above zero for the period up until 2024. Several large mothballed gas-fired power plants are planning to re-enter the market in autumn.

Figure 16 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU27



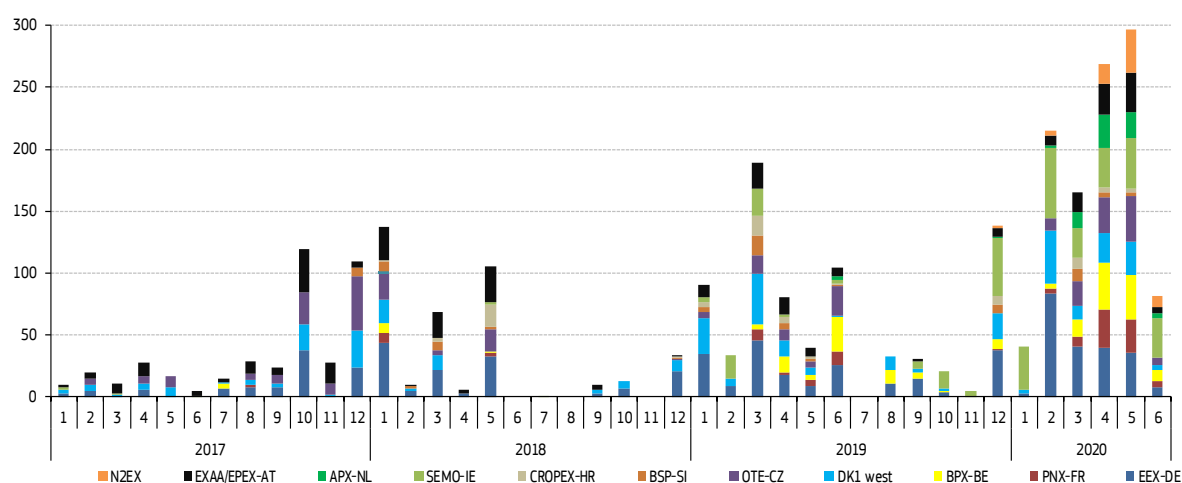
- **Figure 17** illustrates that coal generators across Europe continued to operate in a universally adverse environment in Q2 2020. [Clean dark spreads](#) in all the markets under observation remained in negative territory and mostly followed the developments in power markets. In June, rising carbon costs blunted the effect of higher power prices and put the profitability of coal firing under renewed pressure. At 28 TWh, the total coal generation in the EU27 in the reference quarter was a third lower than in Q2 2019 and the lowest quarterly figure on record. Several markets such as Great Britain or Portugal recorded coal-free weeks or even months. The pandemic has rendered many coal assets in the EU27 unprofitable and hastened their demise. Additional early retirements were announced. In Portugal, the coal-exit date has been brought forward by two years to 2021.

Figure 17 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU27



- **Figure 18** 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.
- At 648, the number of hours with negative wholesale prices in Q2 2020 was almost three times larger in the observed bidding zones than in the previous Q2. The highest numbers of falls into negative territory were concentrated into April and May when the effect of lockdown restrictions was weighing heavily on power demand, which in turn restricted manoeuvring space for conventional generators. The integrated Irish zone recorded the highest number of negative hourly prices (105) in Q2 2020 and was trailed by Germany (84) and Belgium (81). Record low electricity consumption and rising renewable generation brought more cases of negative prices even to markets which traditionally do not display many such instances, such as the Netherlands, France, Hungary and the UK. The pandemic has made balancing the grid a harder task and accentuated the need for more flexibility in the European power system in both directions. It has also intensified the search for market instruments that would find a proper value of flexibility.

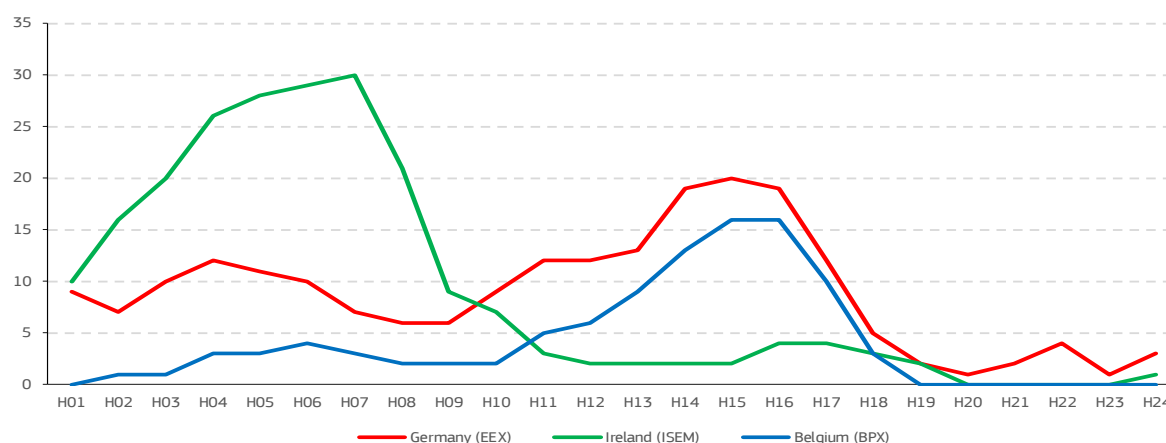
Figure 18 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- **Figure 19** displays the distribution of negative wholesale power prices throughout the day in three selected markets over the first six months of 2020. On the Irish island, negative prices occurred almost exclusively during the night when demand was low and wind generation reached high levels. In Germany and Belgium, the highest concentration of negative hourly prices is visible in the afternoon, coinciding with the peak of solar generation and a midday highpoint of power consumption. High wind generation during the night also brought several instances of prices falling below zero in both markets.

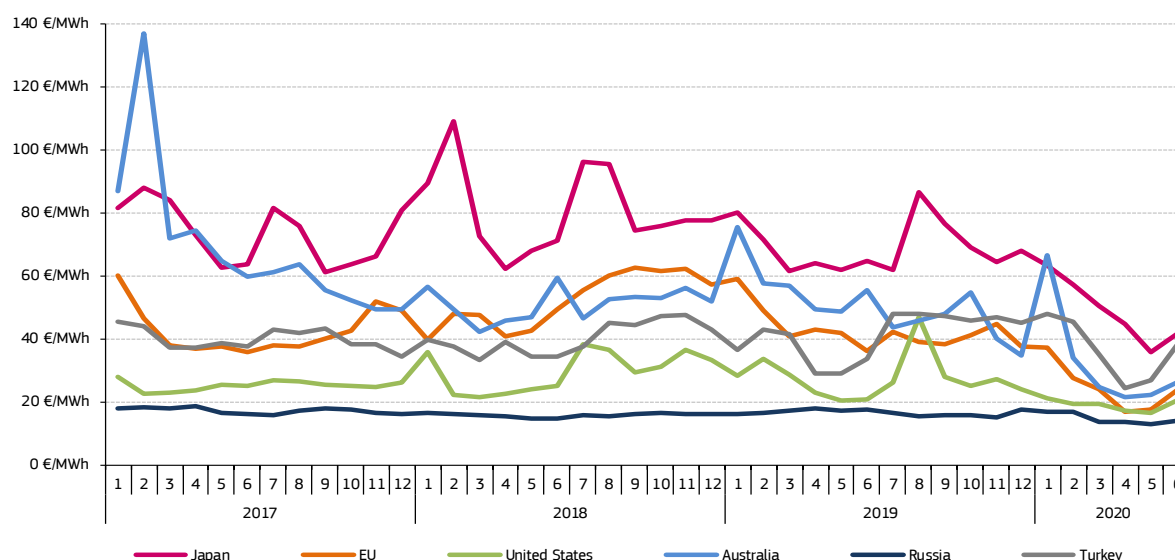
Figure 19 – Daily occurrence of negative hourly prices on selected day-ahead trading platforms in H1 2020



Source: Platts, ENTSO-E.

- **Figure 20** compares price developments in wholesale electricity markets of selected major economies. Prices sank to multi-year lows across the world in April and May, confirming the truly global impact of the coronavirus pandemic on energy markets. Japan remained the most expensive of the markets under observation, with day-ahead prices reaching 41 €/MWh on average during the reference quarter. This was a third lower than in the same period last year. Power prices in Australia registered an even steeper fall, declining by more than half year-on-year to 23 €/MWh. Europe's usual price premium over the United States disappeared for two months as the European Power Benchmark fell under 20 €/MWh for the first time and as the US power demand was relatively less affected by the pandemic. Wholesale prices fell measurably also in Russia which had the cheapest electricity (13 €/MWh) of the selected group in Q2 2020.

Figure 20 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

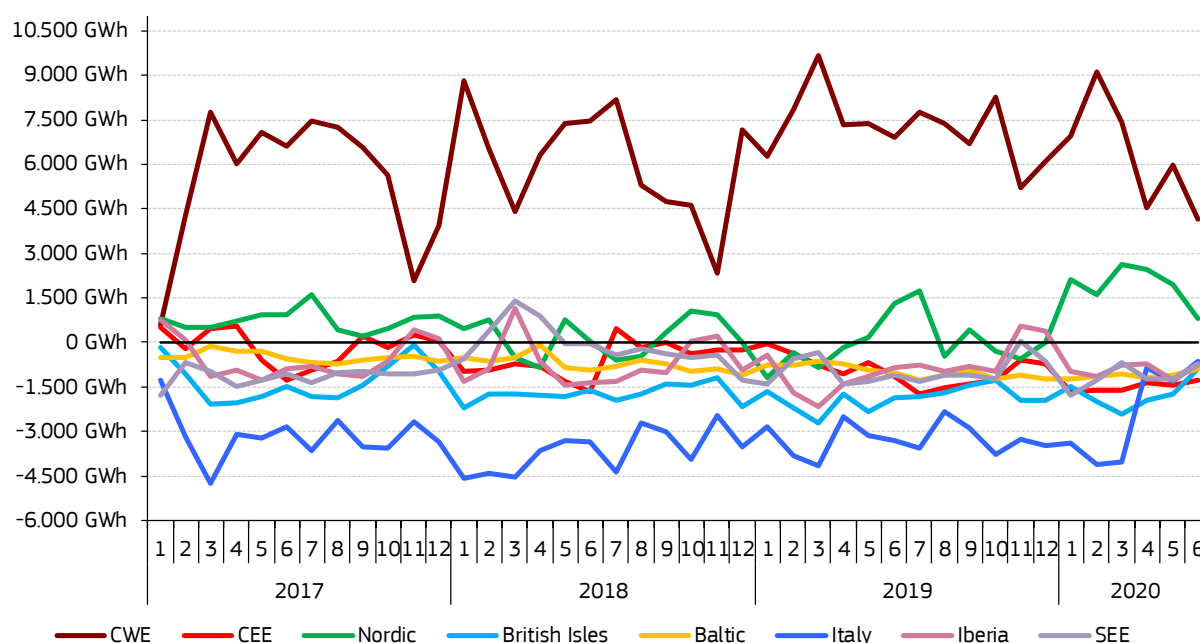


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of PJM West, ERCOT, MISO Illinois and CAISO regional wholesale markets in the United States.

2.2 Cross-border flows

- **Figure 21** reports on the regional cross-border flows of electricity. Central Western Europe retained its position of the main exporting region in Q2 2020, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. However, its net export flows decreased by a third compared to the same quarter a year before to 15 TWh. This was due to increased flows from the Nordic region (mainly Norway) and lower power demand in traditionally importing markets such as Italy or Spain.
- Italian net imports shrank by 69% year-on-year to less than 3 TWh in Q2 2020. This was the lowest figure in records going back to 2013 and sharply contrasted with the situation in the UK which experienced an even greater decrease in power demand than Italy in Q2 2020 (-14% year-on-year), and yet continued to import significant amounts of electricity from the continent. Net flows to the British Isles reached almost 5 TWh in the reference quarter (-22% year-on-year). The difference can be partly explained by the fact that power prices in Italy fell even more than in the UK in Q2 2020, as Italian renewable generation expanded in hydro, wind and solar segments and reduced the need for imports even without the effect of the pandemic. The CEE region's net position (-4 TWh) deteriorated in Q2 2020 compared to Q2 2019 despite large falls in power demand in local economies. This was mainly due to rising Polish and Romanian imports. South Eastern Europe's balance remained in negative territory (-3 TWh), but that was a slight improvement compared to Q2 2019.
- The Nordic region, where consumption levels were less affected by social distancing restrictions, saw net exports remaining at elevated levels as hydro reservoirs in Norway and Sweden had to be relieved to accommodate unprecedented snowmelt in summer. The total net surplus reached 5 TWh in Q2 2020 (up 293% compared to Q2 2019). The Iberian Peninsula reduced net imports from France and Morocco by 0.6 TWh year-on-year in Q2 2020 thanks to high hydro generation both in Spain and Portugal.

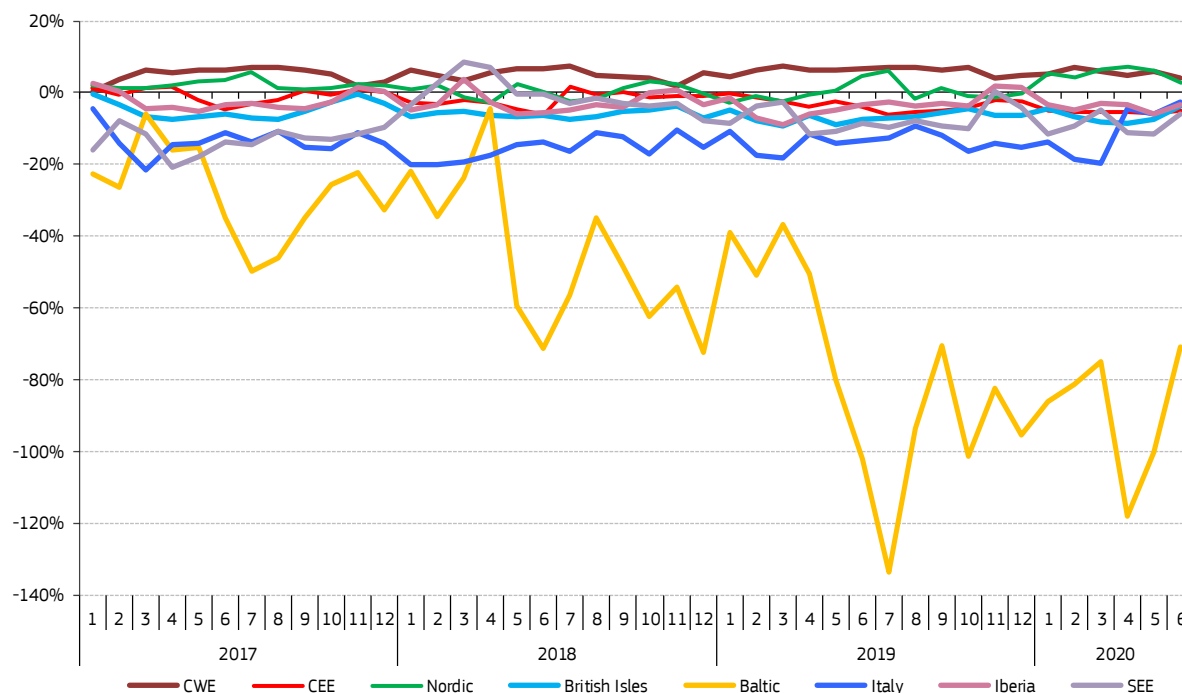
Figure 21 – European cross border monthly physical flows by region



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

- **Figure 22** 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 deteriorated in April and May, as extremely low power prices undermined the competitiveness of local power generators vis-à-vis their peers in the Nordic region. Overall in Q2 2020, net imports of electricity nearly equalled domestic generation. South Eastern Europe became the second biggest importer relative to its production (10%). For the rest of the regions, net imports (or exports) did not exceed 7% of domestic generation.

Figure 22 – The ratio of the net electricity exporter position and the domestic generation in European regions

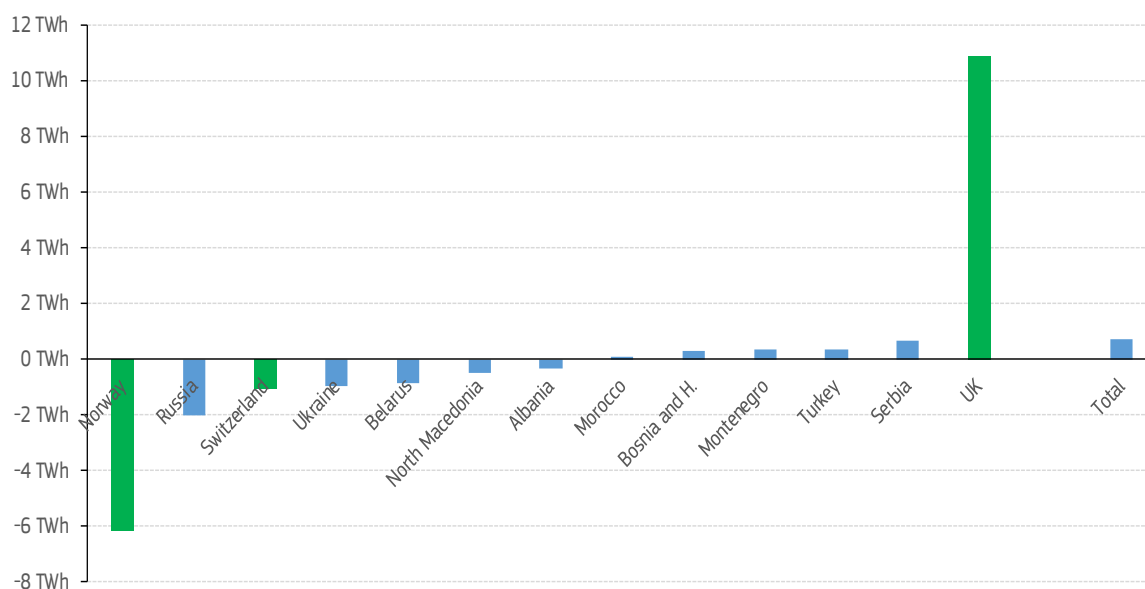


Source: ENTSO-E. Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

3 Focus on electricity trade with EU neighbours

- As shown in **Figure 23**, the EU27 trades electricity with most of its neighbours. The most important partners in terms of volumes are Norway, the UK and Switzerland. In the first two countries, generators are covered by EU ETS obligations and in the Swiss case, the local trading system is linked to the EU ETS. The significance of flows to and from other neighbouring countries varies from region to region but is limited at EU level (gross turnover at borders remained under 2% of the total EU27 consumption in 2019).
- In the first half of 2020 (H1 2020), external flows were influenced by the demand shock caused by the coronavirus pandemic. With a 6 TWh surplus, Norway became the largest net exporter to the EU27 on the back of high levels of competitively priced hydro generation from ample hydro reservoirs. This contrasted with the situation in 2019 during which Norway ran a largely balanced exchange with its interconnected partners (Denmark, Finland, the Netherlands and Sweden). A new 1,400 MW undersea power cable between Germany and Norway was finished in 2020 and is now undergoing tests. As was the case last year, Switzerland also became a net exporter vis-à-vis the EU27 by a slight margin, with most of its flows coming from hydro and nuclear sources. The UK, which is still part of the EU ETS and imposes an additional carbon levy of roughly 20 €/t, became EU's single most important export market in H1 2020, attracting more than 10 TWh of net imports, mostly from Belgium, France, and the Netherlands. Two additional links between the continent and the British zone with a combined capacity of 2,000 MW are planned to go online by the end of 2020.
- Net imports from Russia added up to 2 TWh in H1 2020, falling significantly compared to 2019 when they reached 12 TWh for the whole year. This was mainly due to much lower flows to Finland where a paper mill strike and covid-related disruptions reduced power demand. Net imports from Ukraine decreased on the back of lower demand in Hungary and reached 1 TWh in H1 2020. They totalled 4 TWh for the whole year 2019. Owing to lower consumption in the Baltics, net imports from Belarus also declined. Electricity trade with other countries was generally balanced. The total balance finished with a 0.7 TWh surplus for the first six months of 2020, making the bloc a net exporter of electricity.
- Several new interconnectors are planned between Africa and Europe. A 600 MW subsea cable linking Sicily and Tunisia, which has been included in the list of Projects of Common Interest, should allow reciprocal power exchanges from the second half of this decade. Additional two interconnectors with a combined capacity to transmit 4,000 MW are scheduled to link Cypriot and Greek power grids with Egypt and Israel from 2023.

Figure 23 – Net electricity exchanges with EU27 neighbours in H1 2020

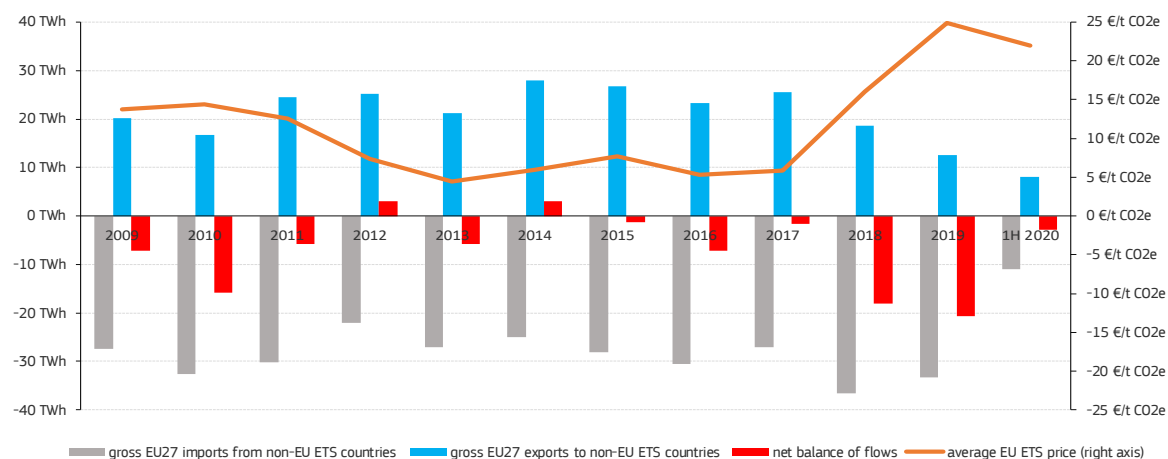


Source: ENTSO-E. The green colour denotes countries in which producers are covered by EU ETS obligations or their local equivalent.

- **Figure 24** shows the evolution of electricity trade between the EU27 and countries in which generators are not subject to EU ETS obligations or their local equivalent. It is apparent that the balance of trade swung decidedly in favour of external generators in 2018 and 2019, which can be partly traced to rising CO₂ prices in the EU ETS as higher carbon costs undermined the competitiveness of EU-based generators vis-à-vis their external peers. The CO₂ emission intensity of power generation in the countries in question is about two times higher on average than in the EU27. The negative correlation between CO₂ prices and EU27 exports to the non-ETS zone is

very high (-0.82) and is greater than the corresponding correlation between CO₂ prices and EU27 imports from the non-ETS zone (-0.58). This suggests that other important factors also influence inflows from the non-ETS zone, such as wholesale electricity prices, weather patterns, power demand or interconnection availability. The year 2020 is a case in point. The deficit in electricity trade improved significantly in the first six months mainly because of low demand in the EU27 and despite relatively high CO₂ prices.

Figure 24 – Electricity flows between the EU27 and countries not part of the EU ETS or its equivalents



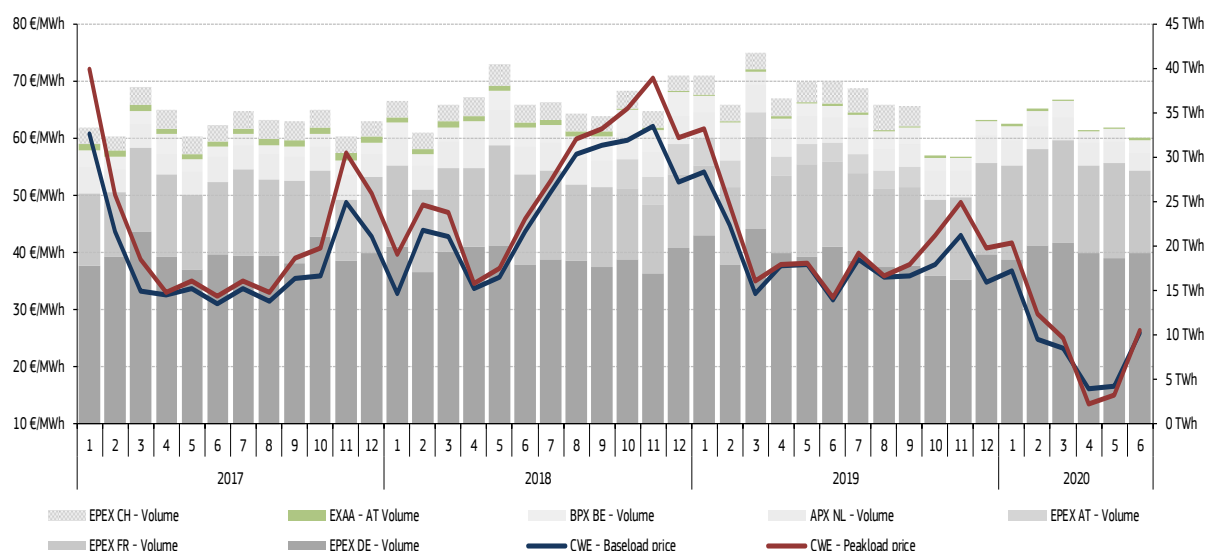
Source: ENTSO-E, Eurostat.

4 Regional wholesale markets

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

- Baseload electricity prices in Central Western Europe (CWE) dived below their peakload peers for the greater part of Q2 2020, a rare occurrence demonstrating the impact of the covid-related demand shock and high solar generation on the local wholesale market. Increased solar penetration, which often depressed prices into negative territory (see **Figure 19**), was magnified by exceptionally sunny weather in April. As consumption slumped in the wake of widespread lockdowns and renewable generation rose to new records, the regional monthly baseload average slid below 17 €/MWh in April and May, the lowest level on records dating back to 2012. Prices rose in June as demand started to gradually recover. Compared to Q1 2020, the average baseload price in the region declined by 44% to 20 €/MWh in the reference quarter. Meanwhile, average peakload prices tumbled by 75% to 18 €/MWh.
- Dramatically reduced generation of the French nuclear fleet, decreased competitiveness of coal and lignite capacities, and record high solar generation impacted production volumes and cross-border flow patterns in the region. Germany and France experienced a combined year-on-year output loss of 35 TWh in Q2 2020, mainly due to falling nuclear and coal generation. This translated into 9 TWh of less exports from the two markets compared to Q2 2019. In Belgium and the Netherlands, higher renewable and gas generation compensated for lower coal and nuclear output. Switzerland managed to keep its production levels largely intact. Austria shut down its last coal power plant in Mellach in April, becoming another Member State to abandon coal for residential heating and power generation.
- Datteln 4, the last coal-fired power plant built in Germany, started commercial operation in May. The 1.1 GW unit, the construction of which began in 2007, will deliver a portion of its output to the local rail operator as well as 380 MW of thermal capacity for district heating. The plant generated more electricity than any other coal-fired competitor in Germany in Q2 2020. It is scheduled to be closed by 2038 at the latest.

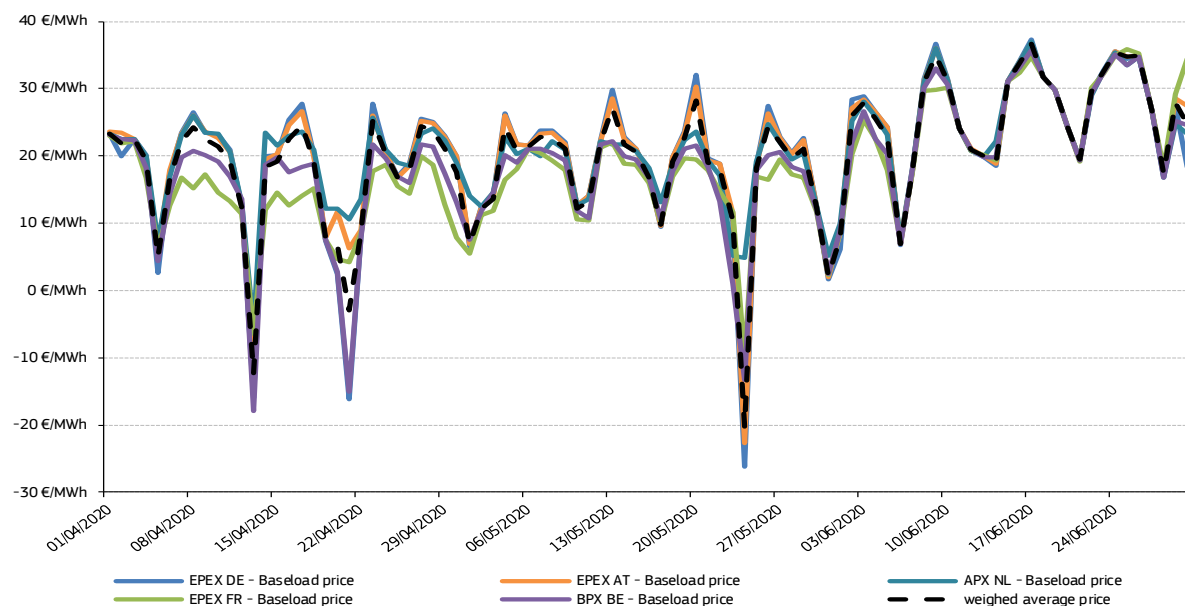
Figure 25 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



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

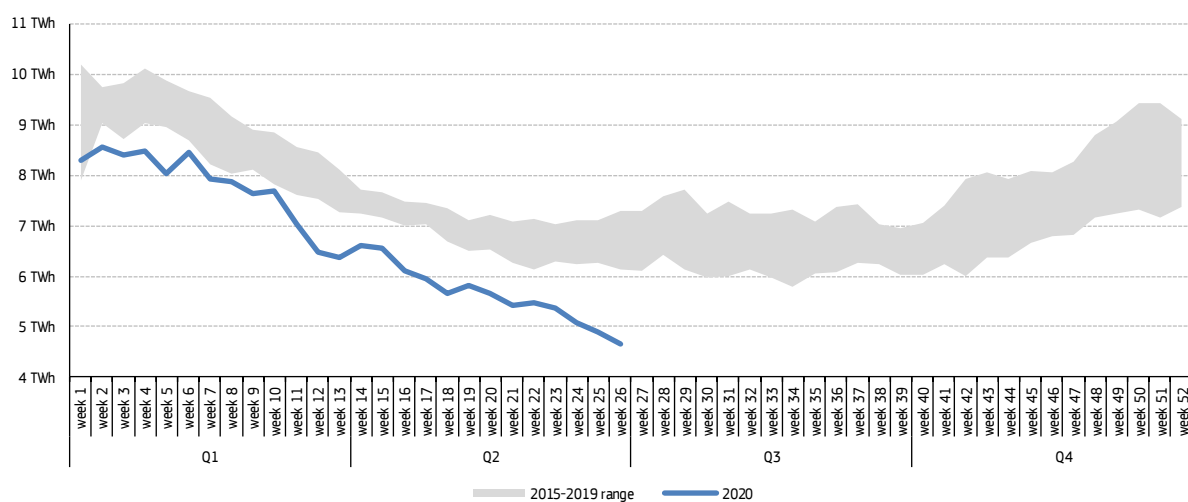
- **Figure 26** shows the daily average day-ahead prices in the region in the reference quarter. April and May witnessed several days of negative power prices in the German and the Belgian market due to low demand and high renewable penetration. Sub-zero pricing was most widely spread on Easter Monday when it affected also the Dutch and the French market for the whole day. In all the instances of daily negative prices, the renewable share of the German power mix exceeded 70%. Average prices did not rise above 30 €/MWh in the first two months of the reference quarter. In June, when prices were lifted by recovering demand, they displayed a high level of convergence.

Figure 26 – Daily average power prices on the day-ahead market in the CWE region



- As shown in **Figure 27**, the French nuclear fleet shouldered the greatest pain of the demand shock during the lockdown period. Apart from low power demand, its performance was also affected by outages and maintenance overruns. The total generation in the reference quarter fell by 21% year-on-year (or 19 TWh). The annual production target was revised significantly downwards due to reduced power consumption and adjustments to maintenance and refuelling schedule necessitated by covid-related restrictions. In February, unit 1 at Fessenheim was shut down and unit 2 followed in June. The disconnection of the oldest running nuclear power plant in France (commissioned in 1978) has left its fleet with 56 reactors. Of these, 27 were available at the end of June.

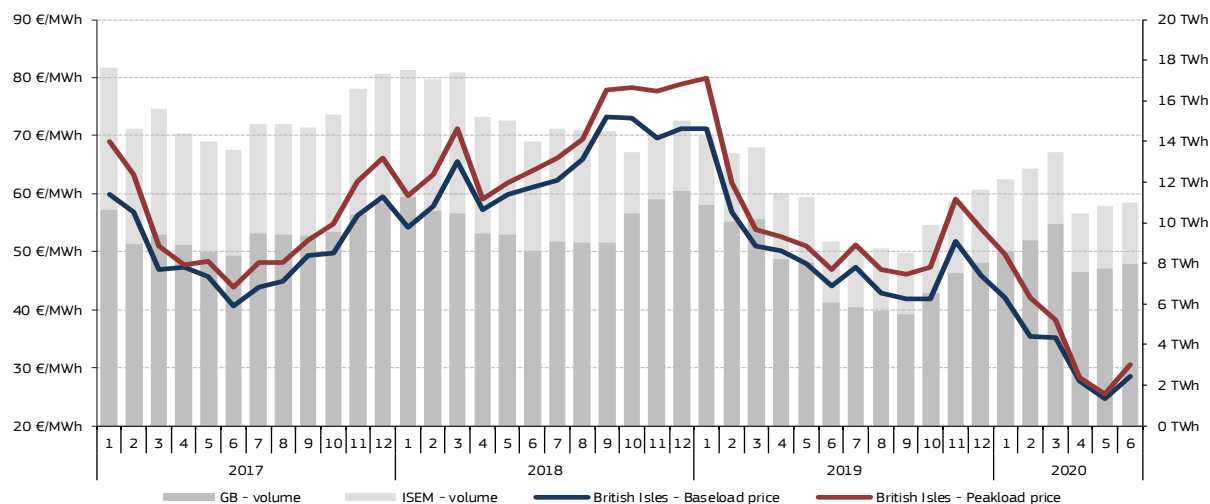
Figure 27 – The weekly amount of generated nuclear electricity in France



4.2 British Isles (GB, Ireland)

- Figure 28** illustrates the monthly volumes and prices on the day-ahead markets in Great Britain and in the all-island integrated market in Ireland. Monthly averages for both baseload and peakload power reached their nadir in May at 25 €/MWh when power consumption was 15% below the last year's levels and when gas prices bottomed out. This was the lowest price since 2003. Compared to Q2 2019, the average baseload price on the British Isles declined by 43% to 27 €/MWh in the reference quarter.
- Trading activity on the British day-ahead market declined in Q2 2020 compared to the previous quarter, but was up 4% in a year-on-year comparison.

Figure 28 – 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 29** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices held under 40 €/MWh throughout the reference quarter and dived below zero on several occasions. The most notable one occurred on 23 May (Saturday) when even the British day-ahead market went negative for 17 consecutive hours (the longest streak on record) amid low weekend demand and 57% renewable penetration. Prices in the all-island Irish market generally followed the British contract albeit with larger volatility caused by fluctuations in wind generation, which constitutes a more important part of the power mix on the Irish island compared to Great Britain. Irish day-ahead prices went negative for a record number of hours in Q2 2020 (see **Figure 18**).
- British power demand dropped to its lowest levels in decades, falling below 17 GW on 28 June. Net demand (without the output of wind and solar) slid to 7 GW at times. Rising renewable penetration and record low demand made the TSO's task keep the electricity system stable more difficult and more expensive since more interventions (curtailment of wind generation in times of excess supply for instance) were needed to maintain the necessary balance between generation and consumption. Also, with lower number of power plants online, balancing prices increased. As a result, the total cost of balancing services in Q2 2020 increased by 79% compared to Q2 2019. In addition, the increased costs are being shared out among a smaller base due to falling consumption.

Figure 29 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland

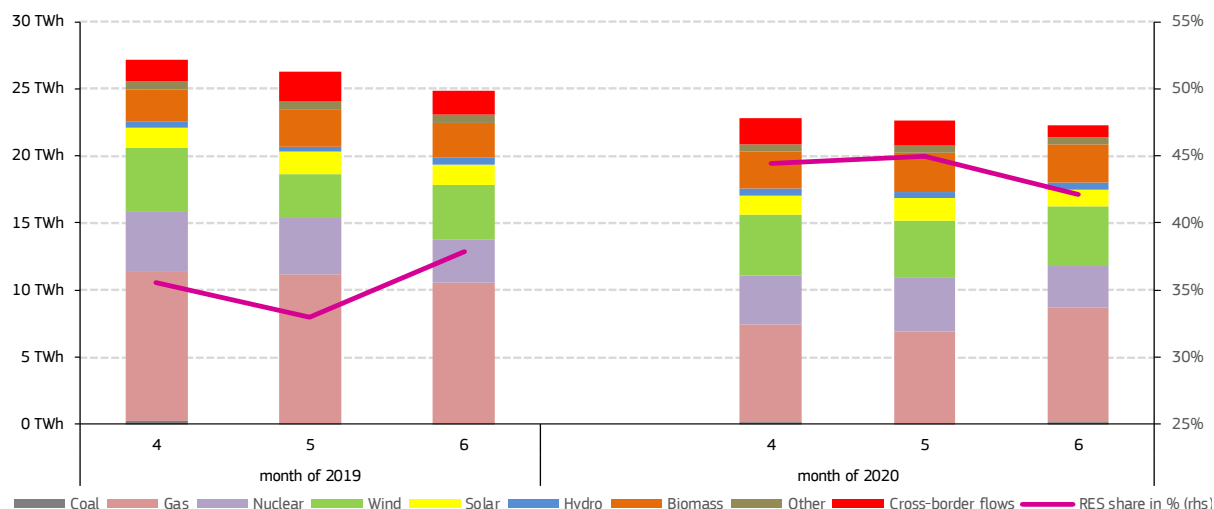


Source: Nord Pool N2EX, SEMO

- **Figure 30** compares the monthly electricity generation mix in the UK between the reference quarter and the quarter a year before. British electricity generation fell by 13% year-on-year in Q2 2020, in line with falling consump-

tion. Gas generation declined by 30% year-on-year, bearing the brunt of the demand shock. Biomass-based output rose by 10%; offshore wind generation surged by 23% compared to Q2 2019. The share of renewable energy sources in the power mix increased to 44% in the reference quarter (from 35% in Q2 2019). The share of gas, meanwhile, declined from 45% to 36%. Coal-firing activity practically ceased. Solar power provided a third of the country's electricity demand on 30 May around noon.

Figure 30 – Monthly evolution of the UK electricity generation mix in Q2 of 2019 and 2020

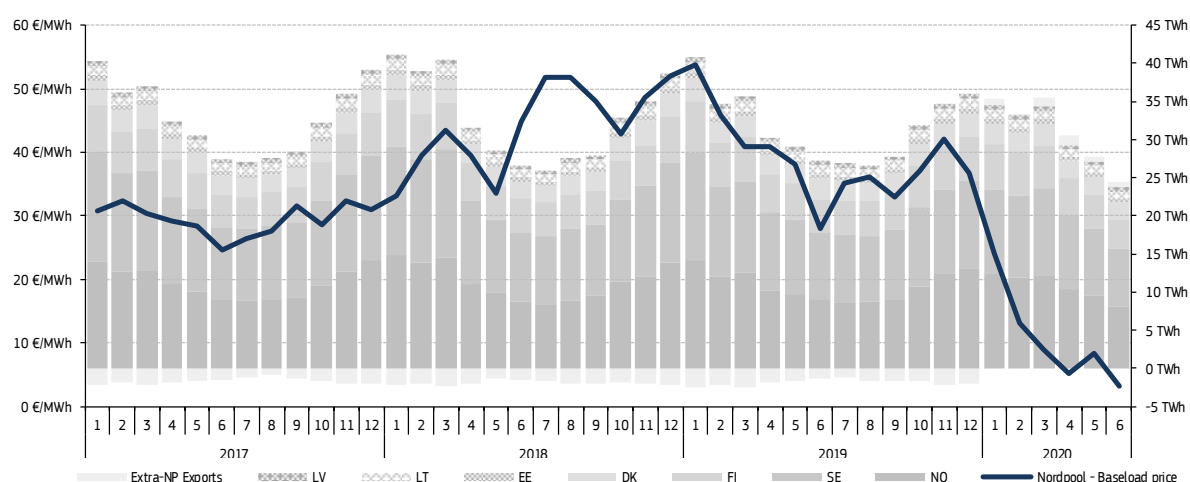


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- As shown in **Figure 31**, system prices in the Nord Pool market remained below 10 €/MWh on average during the reference quarter where they first dived in March. The main reason was record high hydro generation in Norway and Sweden which flooded the market with cheap electricity at a time of below-average demand. The monthly average baseload plunged to 3 €/MWh in June. Compared to Q2 2019, the average system baseload price tumbled by 84% to 6 €/MWh in the reference quarter. Trading activity was little changed compared to the previous Q2.
- With the decommissioning of a coal-fired CHP unit in Stockholm in April, Sweden became the third Member State to exclude coal from its power mix since 2016. The move came two years ahead of schedule.

Figure 31 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe

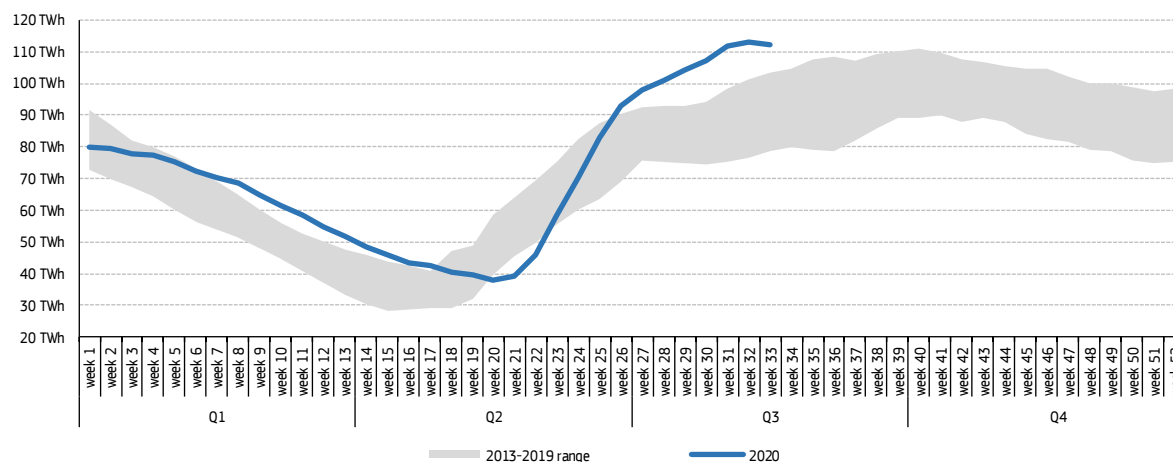


Source: Nord Pool spot market

- **Figure 32** shows the weekly evolution of the combined hydro reservoir levels in the Nordic region (Norway, Sweden and Finland) in 2020 compared to previous seven years. A wet Easter and low demand kept hydro stocks at elevated levels in April. Cooler temperatures and reduced wind and nuclear generation in May saw the drawdown of reservoirs continue unusually longer than normal as producers took advantage of modestly improved spot prices. A quick rebound came afterwards as record high snowpack in Norway started to melt and replenished the de-

pleted stocks. This combined with wet conditions and prompted hydro operators to increase their output to accommodate the large intake without any regard to the price. As a result, the daily system average sometimes fell below 2 €/MWh. Despite high rundowns, hydro stocks finished the reference quarter at above-average levels. The total hydro generation in the region increased by 16% year-on-year to 54 TWh in Q2 2020, contributing to the high net exports of the region (see **Figure 21**).

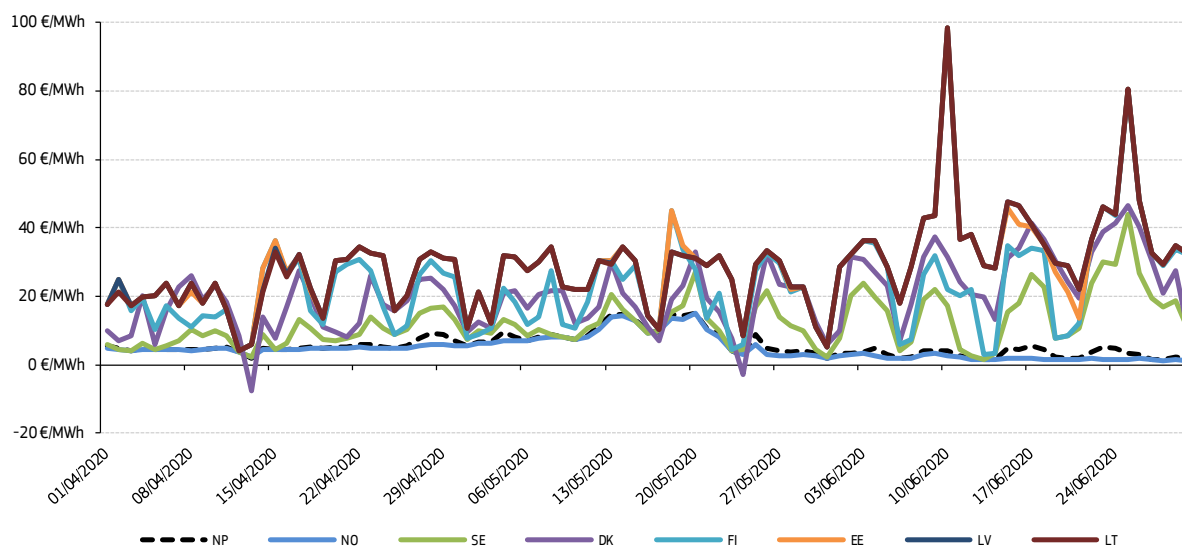
Figure 32 – Nordic hydro reservoir levels in 2020, compared to the range of 2013-2019



Source: Nord Pool spot market

- **Figure 33** shows that average daily prices across Northern Europe continued to display a high degree of divergence in Q2 2020, as in previous quarters. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 22**), registered nearly permanent premiums over the system contract. Limited transfer capacities caused price spikes in the Baltic region and also in Finland in June. High wind generation and low demand brought average Danish prices below the system level on a few occasions. Norway reported daily baseload prices at or below the system price during the reference quarter.

Figure 33 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

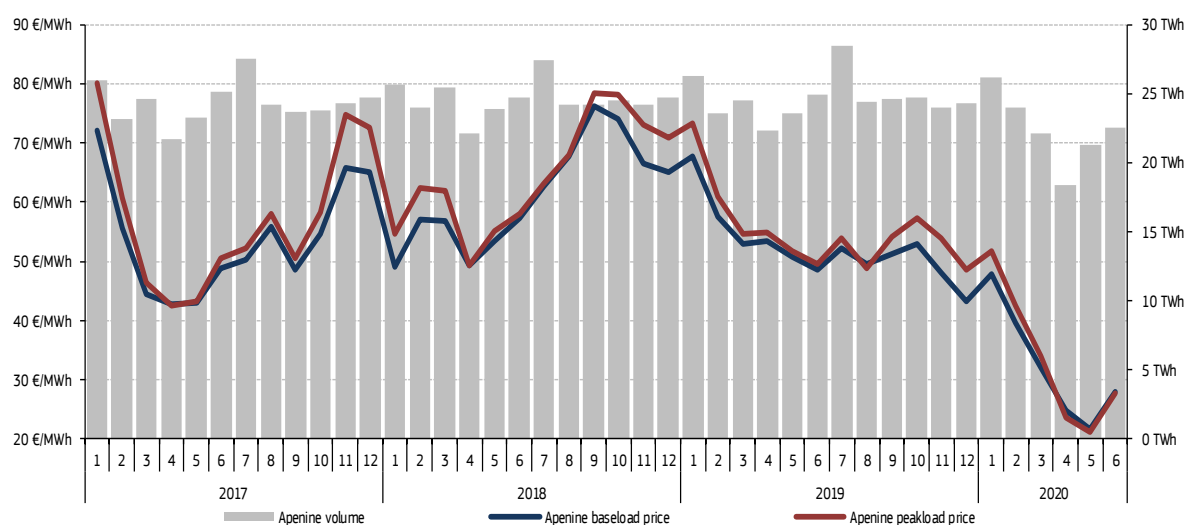


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Similar to the situation in the UK, Italian monthly average baseload electricity prices (**Figure 34**) bottomed out in May at 22 €/MWh, the lowest since 2004. The lockdown restrictions shaved off as much as 20% from power demand in some weeks. Falling gas prices were another factor that exerted downward pressure on the spot market. The average baseload price in Q2 2020 decreased by a 51% compared to Q2 2019 to 25 €/MWh. Meanwhile, the peakload electricity contract switched to a discount to its baseload peer on the back of high solar penetration of the grid. Trading volumes decreased by 12 % compared to the previous Q2.

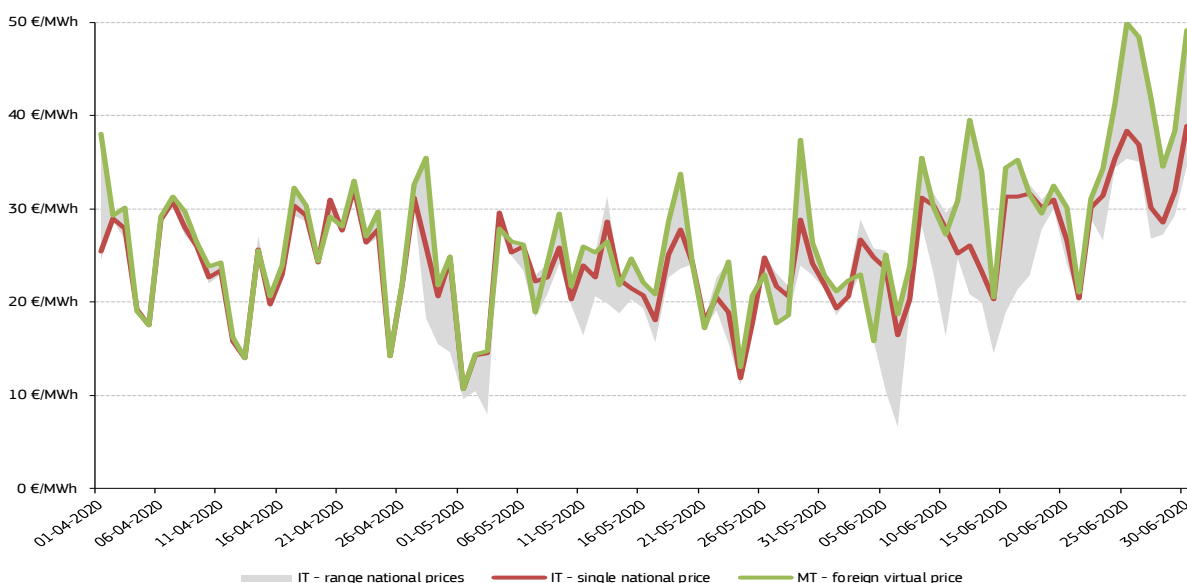
Figure 34 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 35** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. Low demand, which eased pressure on congestion points, caused the usual regional price differences to practically disappear in April. The national average stayed mostly between 10 and 30 €/MWh during the reference quarter and only began to move higher in the final days of June.
- The Italian Power Exchange provides data on foreign price zones such as Malta, in addition to individual regional markets in Italy. The island is a net electricity importer from Italy (through Sicily) and thereby daily prices from the Italian power exchange (especially the Sicilian price zone) influence the Maltese wholesale electricity market. As visible in **Figure 35**, prices in the Maltese zone mostly followed the Italian average in first half of Q2 2020 and formed the upper boundary of regional prices in the second half of the reference period.
- In its power market implementation plan submitted at the end of June, the Italian authorities outlined plans to boost cross-border capacities to meet the 15% interconnectivity target set for 2030. New links to France and Austria with a combined capacity of 1.3 GW are expected to come online this year, and a further 4.1 GW by 2030, including new interconnectors with Austria, Montenegro, Tunisia, Slovenia and Switzerland.

Figure 35 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

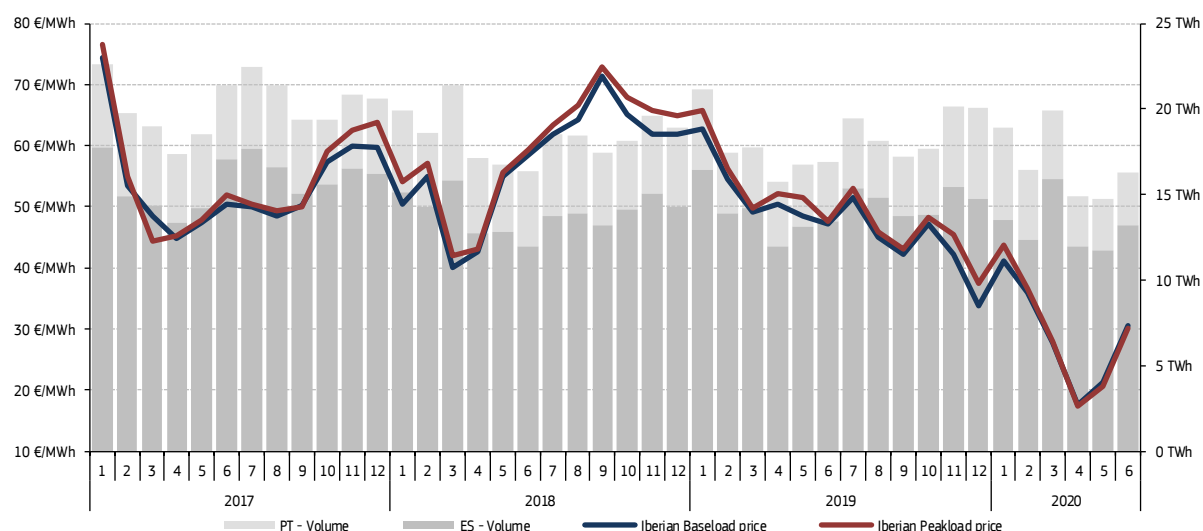


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- Figure 36** reports on monthly average baseload and peakload contracts in Spain and Portugal. The region saw the average baseload price falling below 20 €/MWh in April and gradually recovering to 30 €/MWh by June. Similar to the situation in Italy, the Spanish economy was severely affected by social distancing measures and experienced one of the largest falls in electricity consumption in Q2 2020. High solar output and improved hydro generation also kept prices under pressure. Compared to Q2 2019, the average baseload price declined by 52% to 23 €/MWh in the reference quarter. Trading activity was 4% lower compared to the previous Q2.

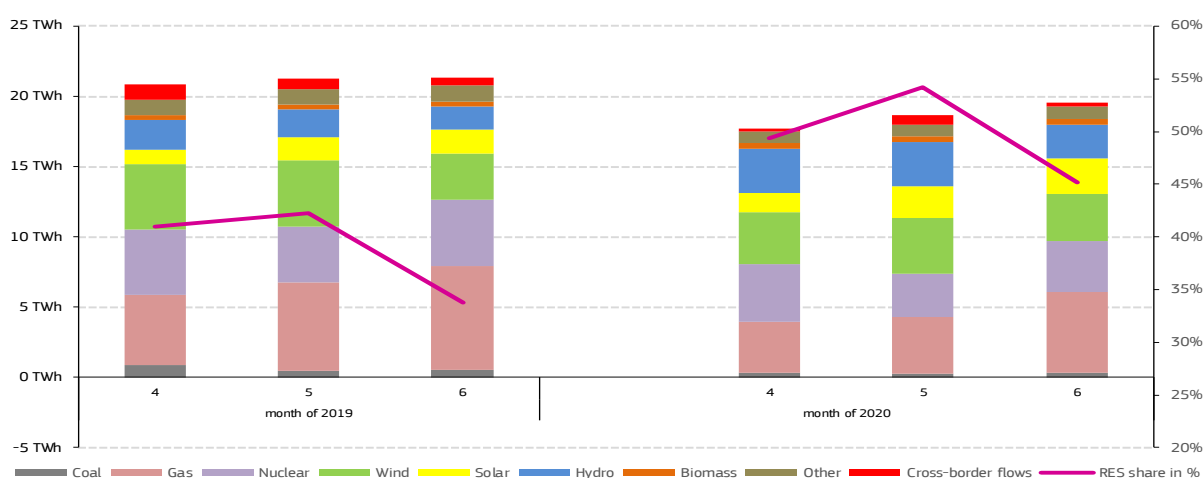
Figure 36 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- Figure 37** displays the evolution of the monthly electricity generation mix in Spain during the second quarter of 2020, as well as during the same period of the previous year. A sharp fall in consumption together with rising hydro and solar generation caused the share of renewable electricity sources to reach the 50% mark in the reference quarter, up from 39% a year before. Squeezed out by falling demand and surging renewables, gas generation fell by 28% year-on-year in Q2 2020. Thus, the share of gas in the mix shrank from 31% in Q2 2019 to 25% in Q2 2020. Coal stopped playing any meaningful role and its presence was lower than that of oil. The share of nuclear in Spain's mix, at 20%, was two percentage points lower compared to Q2 2019.
- 20 coal units with a total capacity of 6.2 GW were retired at the end of June. This leaves another five units amounting to 3.3 GW connected to the grid. However, only two of them have been in regular operation in 2020.

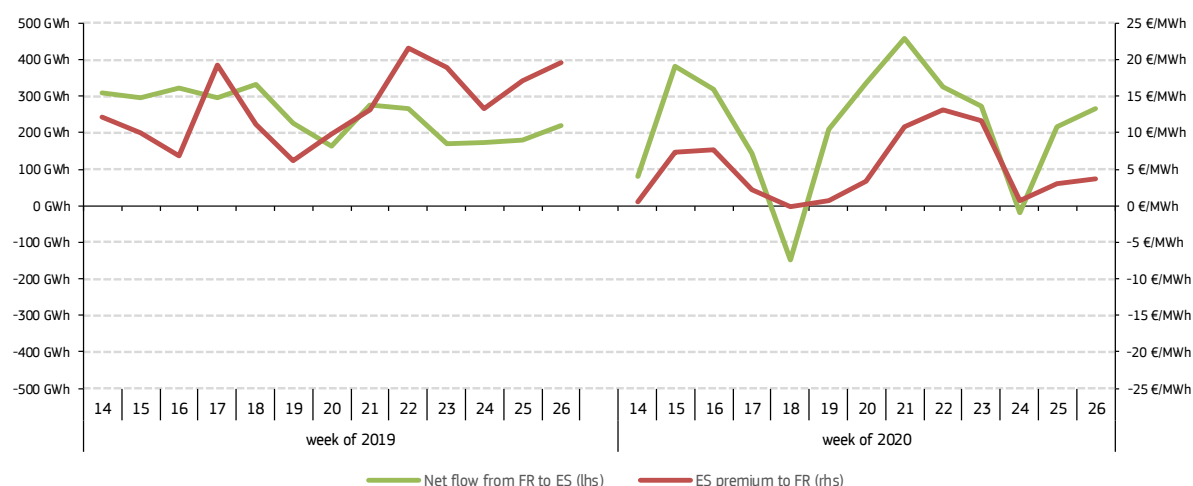
Figure 37 – Monthly evolution of the electricity generation mix in Spain in Q2 of 2019 and 2020



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

- **Figure 38** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. With the exception of two weeks, Spain kept its usual premium over the French day-ahead price throughout Q2 2020. The only significant reversal came at the end of April when high wind and solar generation coincided to drive the Spanish renewable penetration above 70% and France became a net importer of cheaper Spanish electricity. Cross-border flows generally followed price differentials, adding up to 3 TWh of net imports from France (down by 12% from Q2 2019). Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.
- Bilateral trade with Morocco in Q2 2020 developed in Spain's favour and resulted in net exports of 77 GWh from Spain. The Spanish grid operator has completed and undersea cable that links the whole Balearic Islands system to the mainland. The new link between Menorca and Majorca entered into service and means that the four principal islands of the chain are now connected to the continent for the first time.

Figure 38 – Weekly flows between France and Spain and price differentials between them

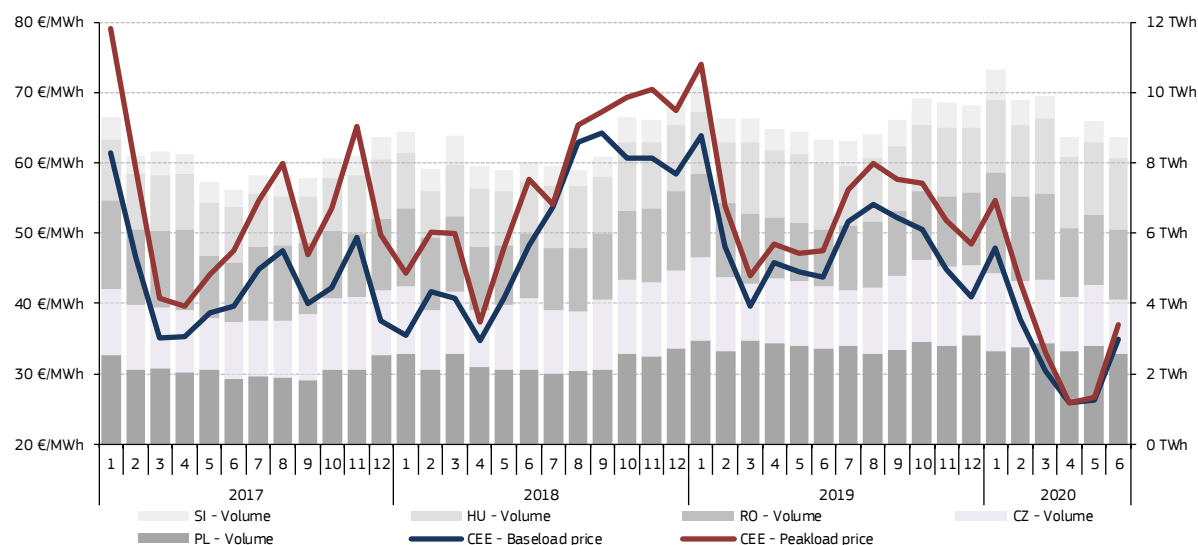


Source: ENTSO-E, OMEL, Platts

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

- **Figure 39** shows that average monthly prices for baseload power in Central Eastern Europe fell to 26 €/MWh in April and May amid widespread lockdowns and restrictions on economic activity which curbed power demand. Prices then move towards 35 €/MWh as consumption began to slowly recover. The peakload monthly average fell under the corresponding baseload contract in April for the first time since 2016, signifying the rising importance of solar PV in the regional electricity mix. When compared to Q2 2019, the average baseload price in the reference quarter fell by 35% to 29 €/MWh. Traded volumes in the reference quarter remained largely unchanged compared to Q2 2019.
- Relatively high carbon prices continued to put a strain on local lignite and coal power plants, forcing the region to import 4 TWh of electricity in the reference quarter on a net basis, up from 3 TWh a year earlier. Poland alone increased its net imports to nearly 4 TWh in Q2 2020 (up from 3 TWh in Q2 2019). Germany, Austria, Nord Pool markets and Ukraine were the largest sources of inflows into the region.

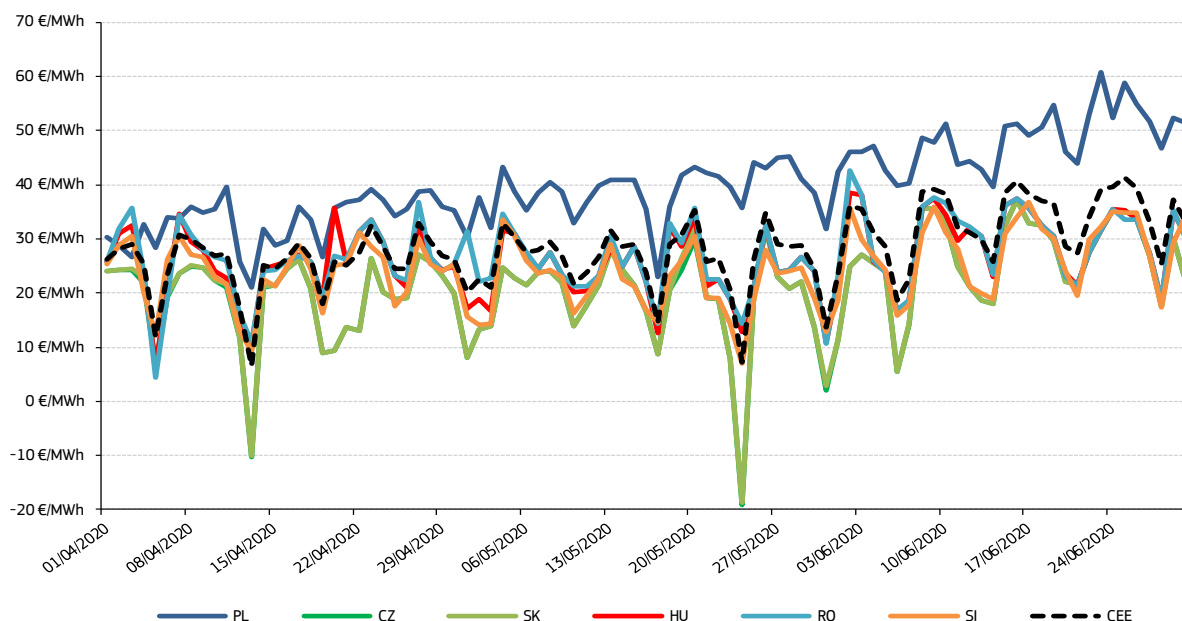
Figure 39 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 40** shows that daily average baseload prices in the four coupled markets (CZ, SK, HU, RO) moved in a relatively compact band in Q2 2020, with few extremes on the downside when low or negative German prices were exported into Czechia and Slovakia. Occasional supply or interconnector issues were usually mitigated by low consumption. The lowest prices, as usual, were reported in Czechia, the regional exporter number one, and its well-connected neighbour Slovakia. Baseload contracts in Poland, which increased imports significantly compared to Q2 2019, were almost constantly 10-15 €/MWh above the regional average and the difference grew even wider towards the end of the quarter.

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



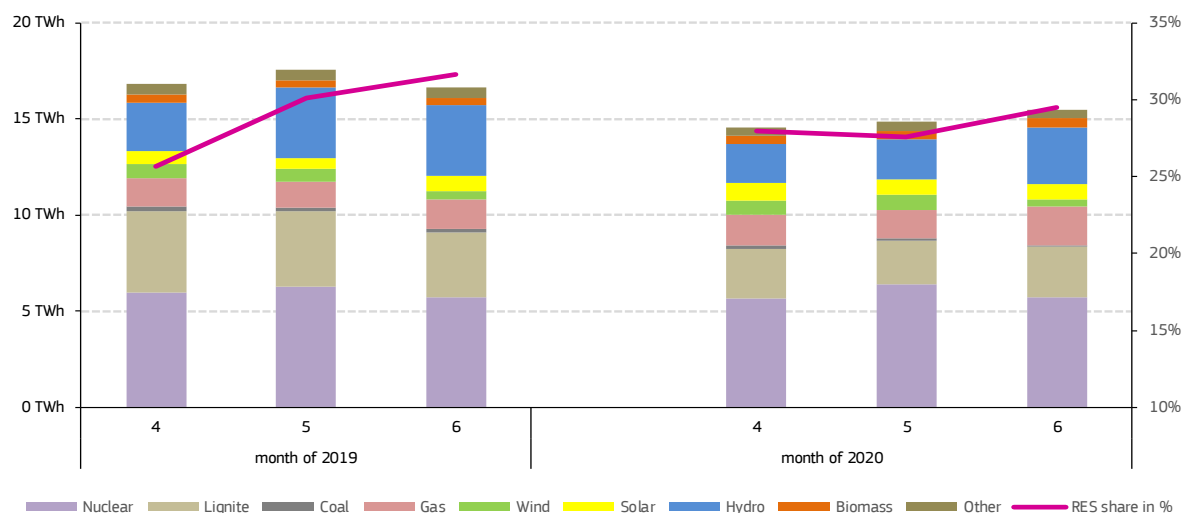
Source: Regional power exchanges

- **Figure 41** compares the combined electricity generation mix of the CEE region (excluding Poland) between the reference quarter and the quarter a year before. Thanks to good availability of local reactors and lower consumption, nuclear generation increased its share of the mix to 40% in Q2 2020 (up from 35% a year before). The reduced competitiveness of lignite generation due to still relatively high CO₂ prices and low power prices caused the combined share of lignite and coal in the reference quarter to fall from 24% to 18% year-on-year, while gas managed to increase its share from 9% to 11% year-on-year. Renewable energy sources (wind, solar, hydro and biomass) accounted for 28% of the total electricity production in the reference quarter, down from 29% in Q2

2019. This was due to a large shortfall in hydro generation (-2.7 TWh) which could not be compensated by higher solar generation (+0.4 TWh).

- 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 went down measurably to 69% in the reference quarter (compared to 74% in Q2 2019), while renewables increased their share from 15% to 19% year-on-year thanks to higher solar and biomass generation. Gas increased its share in the mix from 10% to 12% year-on-year. Poland's solar PV capacities have been growing rapidly thanks to the introduction of an auction support system and grants for rooftop installations. Over 2 GW were registered by the local TSO by the end of June (up from 0.8 GW in Q2 2019).

Figure 41 – Monthly evolution of the electricity generation mix in the CEE region (excluding Poland) in Q2 of 2019 and 2020

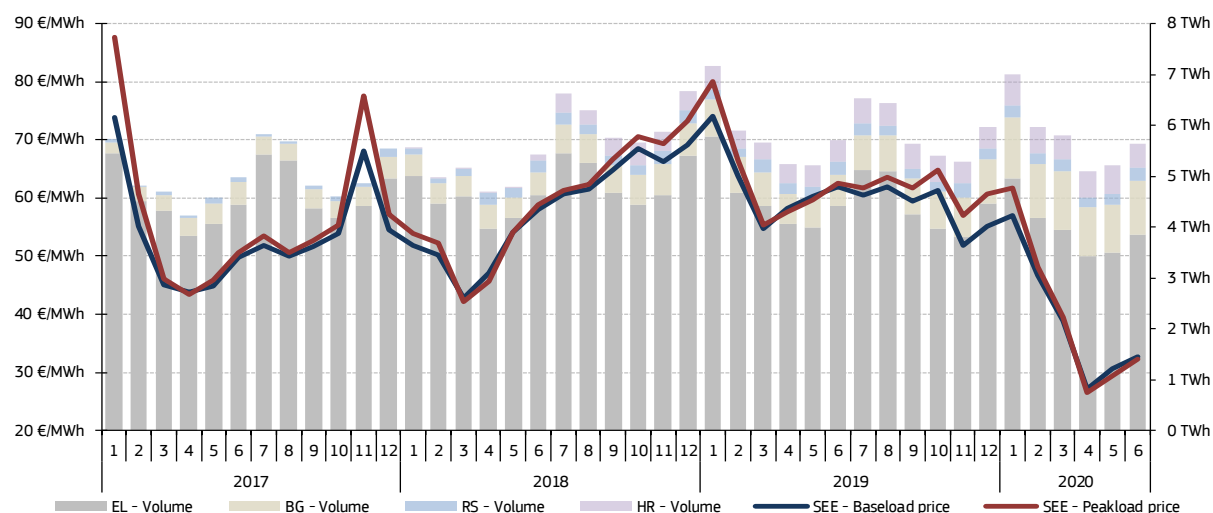


Source: ENTSO-E.

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

- **Figure 42** shows that trade-weighted monthly average baseload prices in the SEE region bottomed out at 27 €/MWh in April and were gradually rising in May and June. For the whole Q2 2020, the regional baseload price stood at 30 €/MWh (down from 60 €/MWh in Q2 2019). Peakload prices stayed below their baseload peers throughout Q2 2020 due to the outsized influence of the Greek market where solar generation plays an important role.

Figure 42 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)

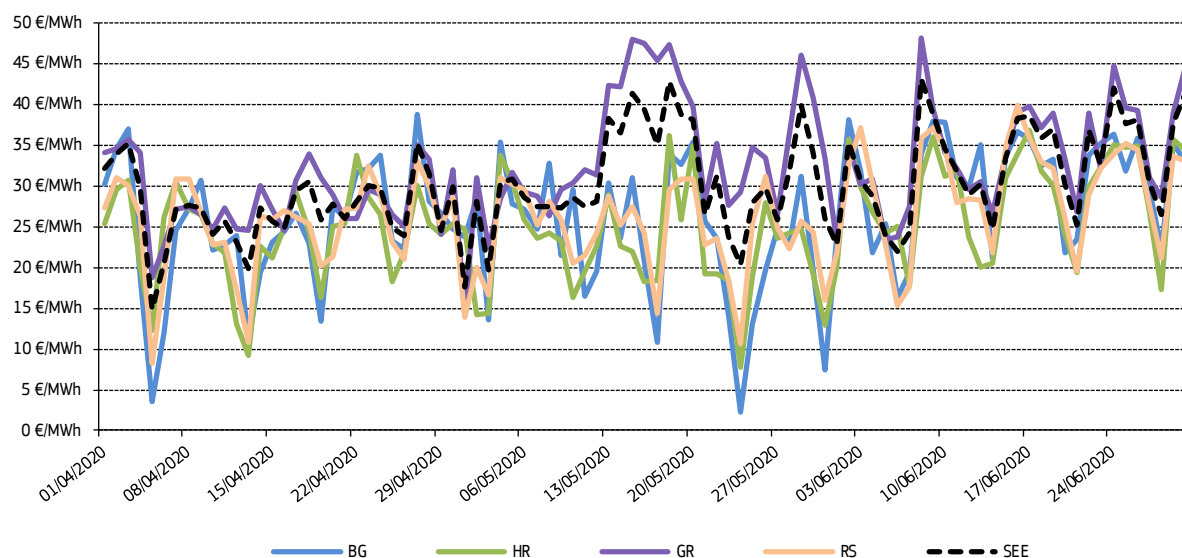


Source: IBEX, LAGIE, CROPEX, SEEPEX

- Apart from Greece, daily baseload price movements in individual markets were relatively well synchronized during Q2 2020, as shown in **Figure 43**. The usual Greek premium over Bulgarian contracts decreased significantly in the

reference quarter due to strong lignite-to-gas switching and a large drop in consumption in Greece which allowed local power prices to stay relatively low. Bulgaria, meanwhile, experience a smaller demand shock which limited the downside potential in its day-ahead market. As a result, baseload prices in Greece decreased by half in a year-on-year comparison in Q2 2020, while their Bulgarian peers went down only by 36% year-on-year.

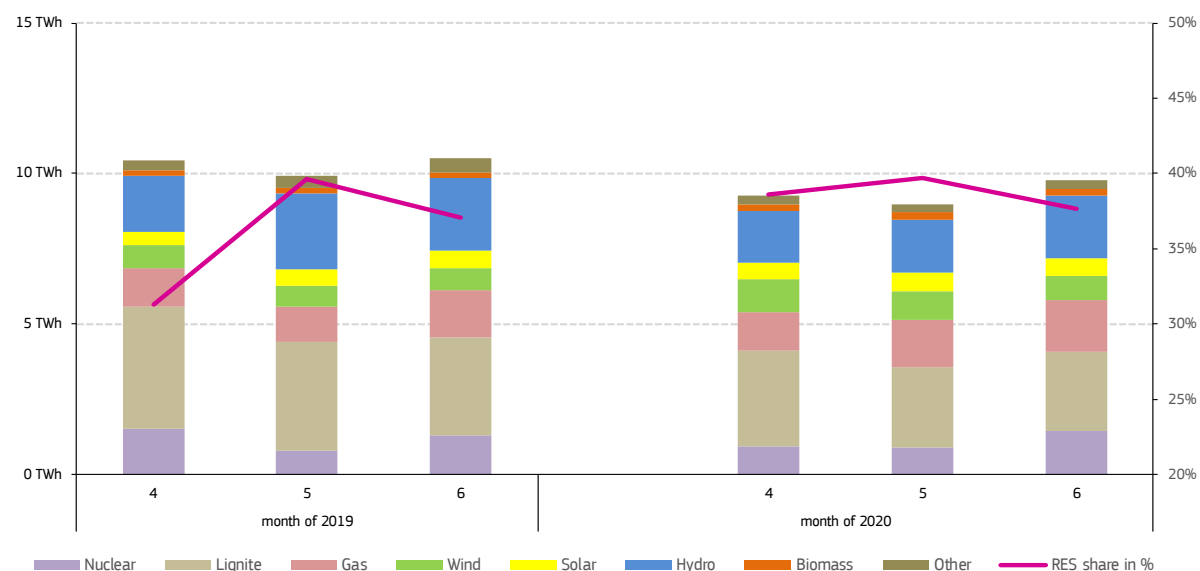
Figure 43 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 44** compares the combined electricity generation mix of the SEE region between the reference quarter and the quarter a year before. Lignite generation bore the brunt of the demand shock caused by lockdown measures, falling by 2.5 TWh year-on-year and taking a 30% share in the regional power mix (down from 35% in Q2 2019). The share of renewables increased from 36% to 39% year-on-year thanks to rising wind and solar generation. The share of gas rose to 16% (from 13% in the previous Q2) on the back of significant coal-to-gas switching in Greece.

Figure 44 – Monthly evolution of the electricity generation mix in the SEE region in Q2 of 2019 and 2020



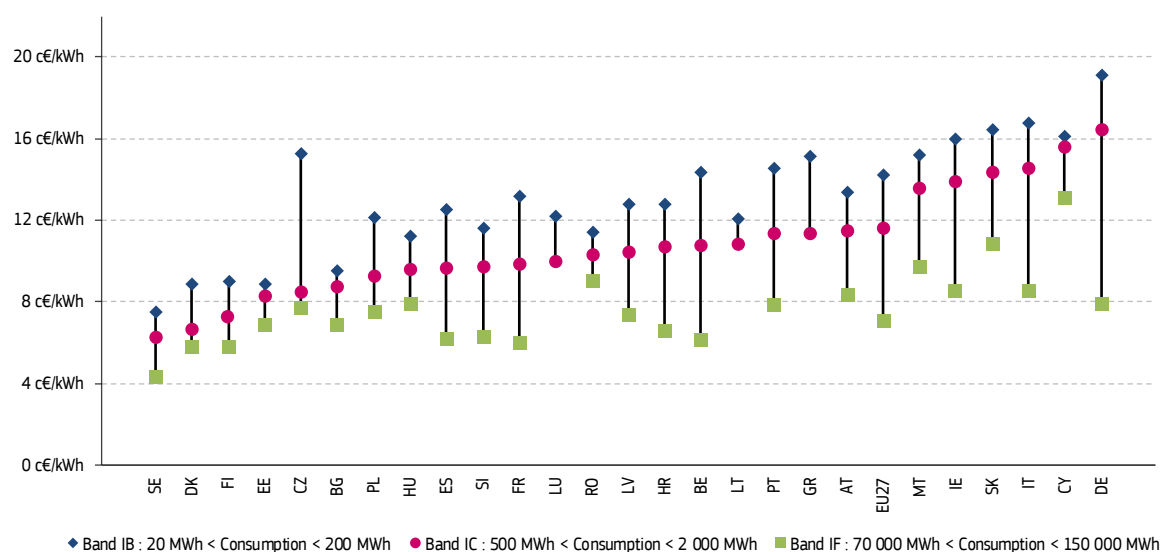
Source: ENTSO-E.

5 Retail markets

5.1 Retail electricity markets in the EU

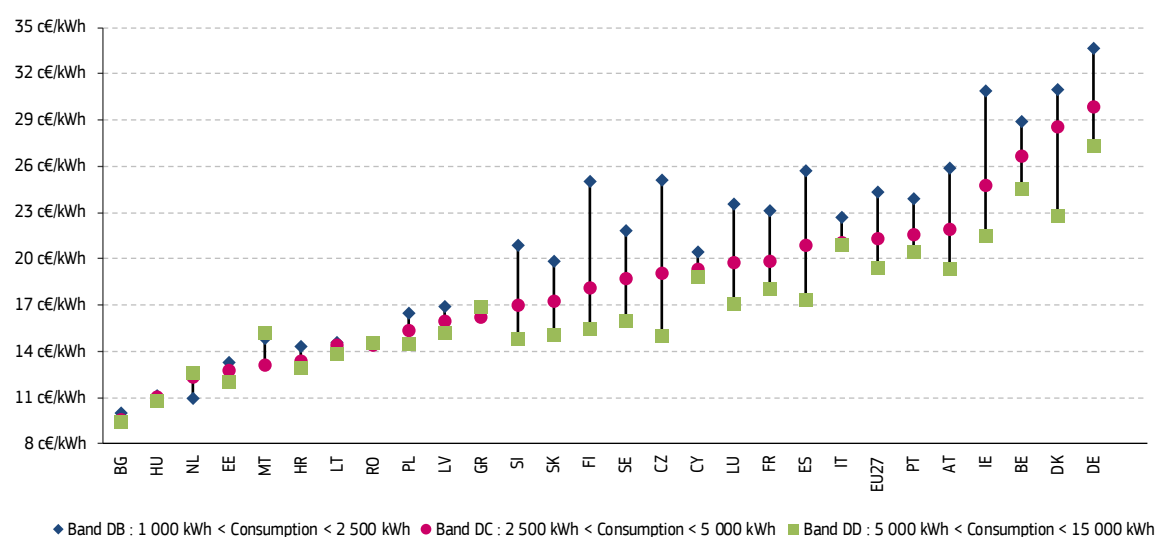
- **Figures 45 and 46** display the estimated [retail prices](#) in June 2020 in the 27 EU Member States for industrial customers and households. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers and bands DB, DC and DD for households). In most cases it holds for both consumer types that the lower the consumption, the higher the price of one unit of electricity (per MWh consumed).
- Smaller industrial consumers (band IB) were assessed to pay the highest prices in Germany (19.1 c€/kWh) and Italy (16.7 c€/kWh), followed by Slovakia and Cyprus (16.4 and 16.1 c€/kWh respectively). The lowest prices in the same category were assessed to be in Sweden (7.5 c€/kWh) and Denmark (8.8 c€/kWh). The ratio of the largest to smallest reported price was nearly 3:1. 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 Cyprus (13.1 c€/kWh), Slovakia (10.8 c€/kWh) and Malta (9.7 c€/kWh). Sweden (4.3 c€/kWh) was assumed to have by far the lowest prices, followed by Denmark. The ratio of the highest to lowest price for large industrial consumers was slightly over 3:1 for this consumer type. Compared to June 2019, the average assessed EU27 retail electricity price for the IF band decreased by 9% to 7.0 c€/kWh.
- In June 2020, Germany (27.4 c€/kWh) was assessed as having the highest electricity price for large household consumers (band DD), followed by Belgium (24.5 c€/kWh), and with Denmark (22.8 c€/kWh) in the third place. The lowest prices for big households were calculated for Bulgaria (9.4 c€/kWh) and Hungary (10.8 c€/kWh). In the case of small households, Germany was again evaluated as having the highest price (33.6 c€/kWh), followed by Denmark and Ireland, while Bulgaria and Hungary found themselves again on the other side of the price spectrum. Compared to June 2019, the average assessed EU27 retail electricity price for the DD band decreased by 2% to 19.4 c€/kWh.

Figure 45 – Industrial electricity prices, June 2020 – without VAT and recoverable taxes



Source: Eurostat, DG ENER. Data for the IF band for LU, LT and GR are either confidential or unavailable. Data for NL are unavailable due to significant changes in the taxation structure affecting different sectors unevenly.

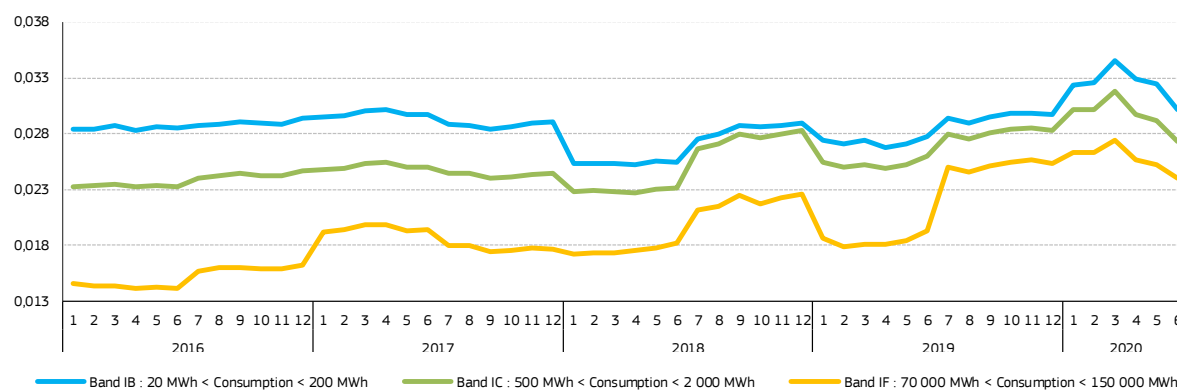
Figure 46 – Household electricity prices, June 2020 – all taxes included



Source: Eurostat, DG ENER

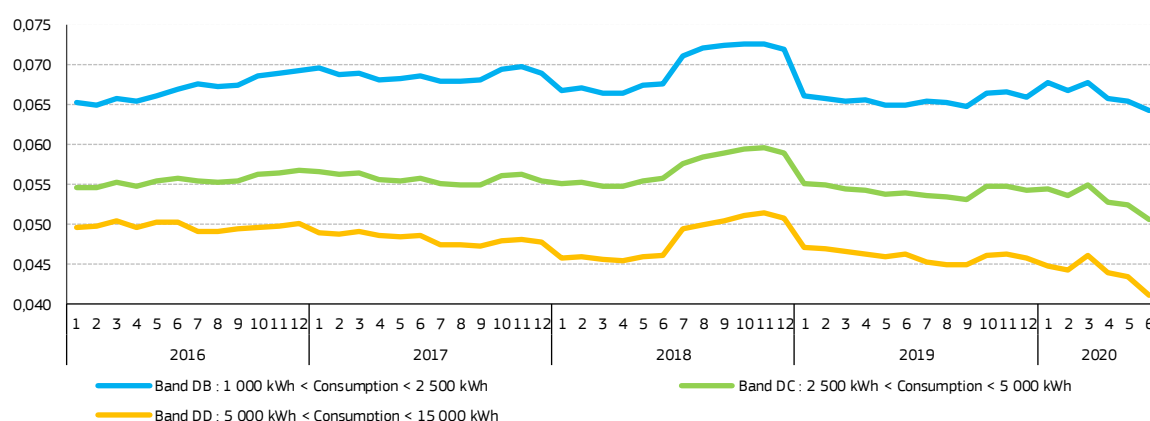
- **Figures 47 and 48** display the convergence of retail prices across the EU27 over time, by depicting their standard deviation. After reaching a peak of divergence in March, all industrial end-user prices began to converge again in Q2 2020, with large- and medium-sized businesses falling below divergence levels from December 2019.
- In the case of households, prices moved increasingly in the same direction across all three consumer bands during Q2 2020. In fact, they reached the highest level of convergence on record. Household prices tend to be more impacted by regulated elements (network charges, taxes and levies) so their variation across Member States is greater than in the case of industrial consumers.

Figure 47 – Standard deviation of retail electricity prices in the EU27 for industrial consumers



Source: Eurostat, DG ENER

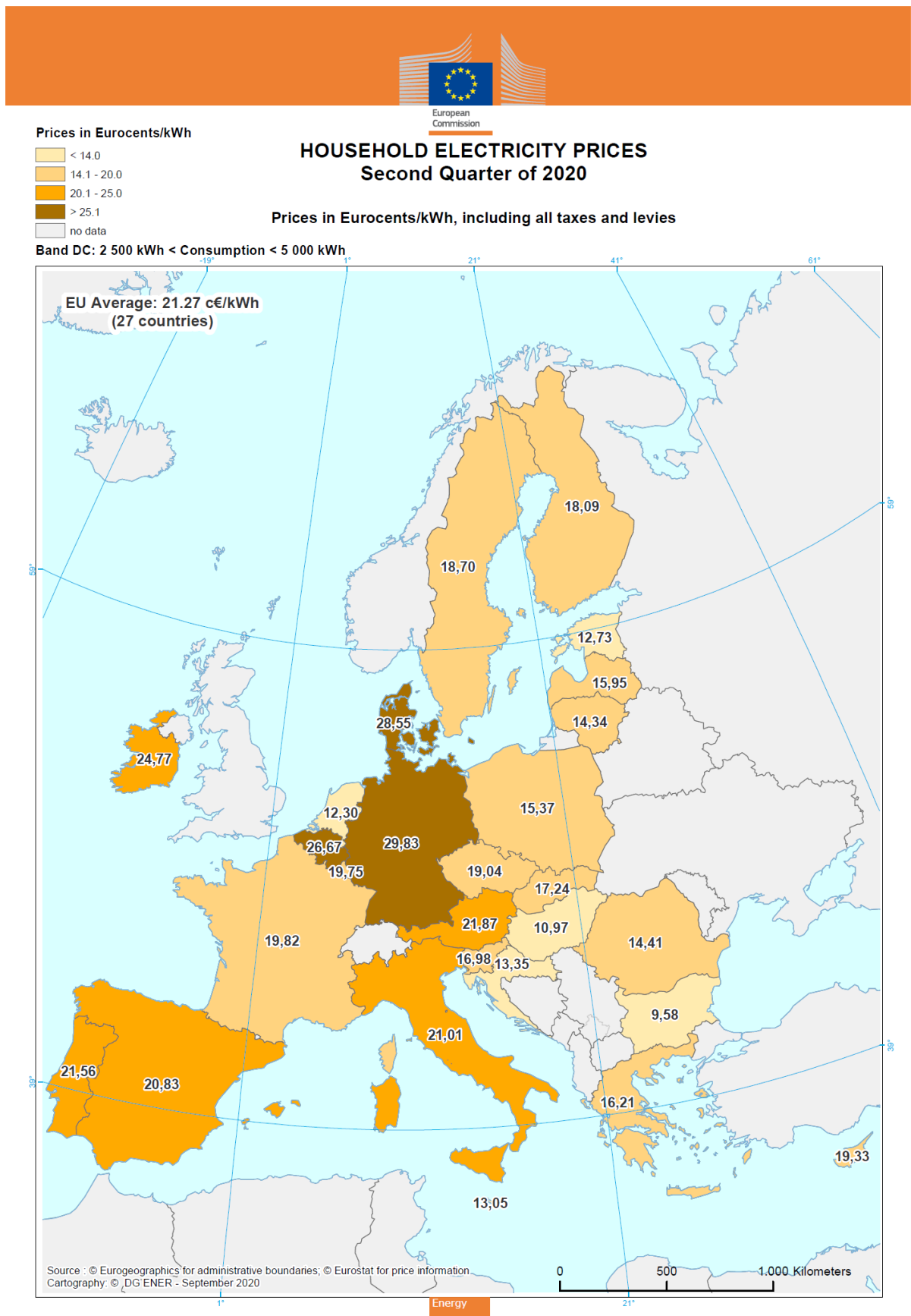
Figure 48 – Standard deviation of retail electricity prices in the EU27 for household consumers



Source: Eurostat, DG ENER

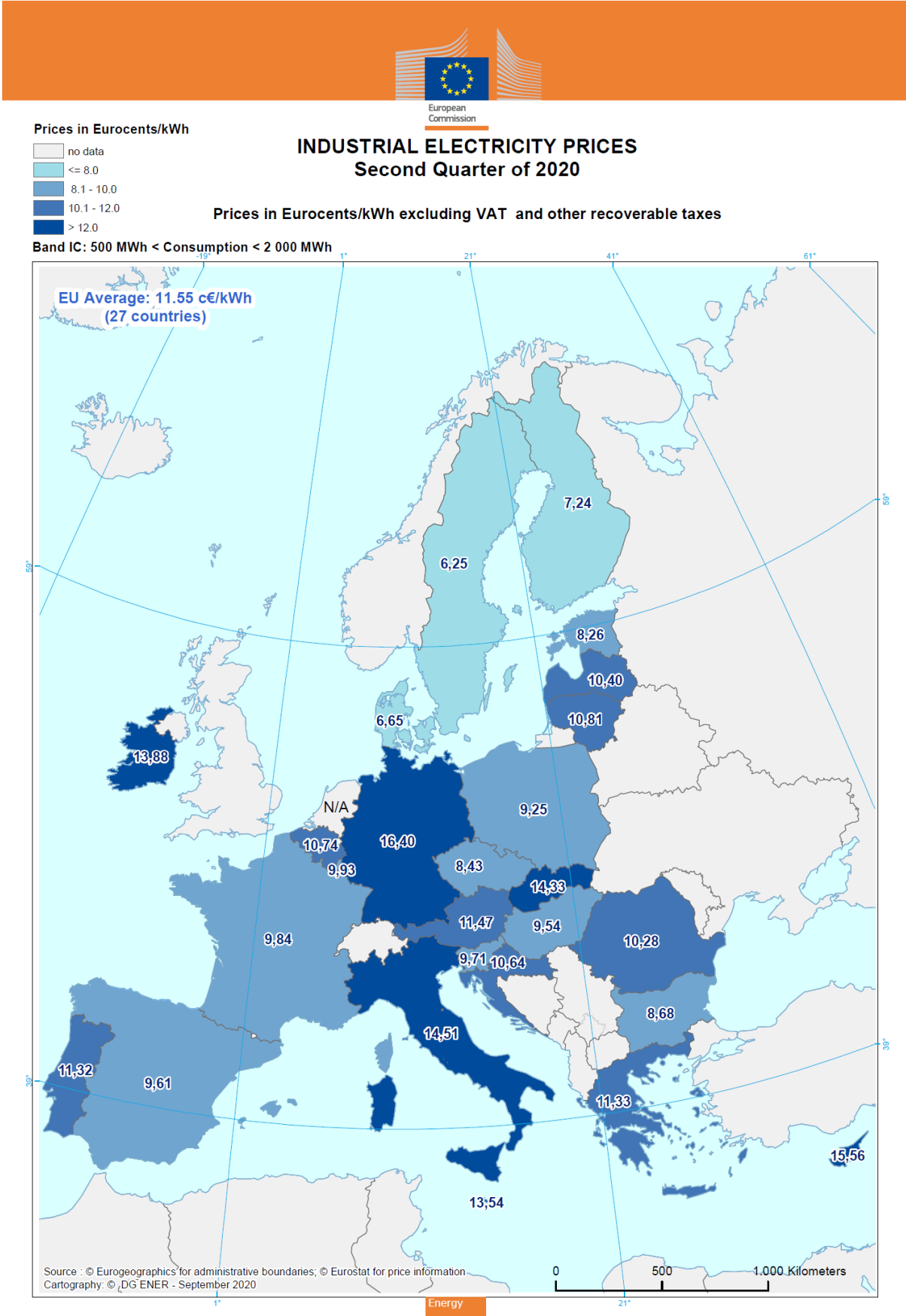
- **Figures 49 and 50** display the estimated electricity prices paid by EU27 households and industrial customers with a medium level of annual electricity consumption in the last month of Q2 2020. In the case of household prices, Germany topped the list (29.83 c€/kWh), followed by Denmark and Belgium. As was the case in previous quarters, Bulgaria retained its position as the country with the cheapest household electricity prices, with Hungary assessed to be in the second place. The average price for the EU27 decreased by 1% in the reference quarter compared to June 2019. The largest year-on-year increases in the household category were assessed in Poland and Lithuania (+14%), followed by Luxembourg (+10%). The biggest year-on-year falls were estimated for the Netherlands (-40%, see **Figure 51** for more details) and Cyprus (-15%).
- In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q2 2020, followed by Denmark and with Denmark taking the third place. Meanwhile, Italy and Germany stood at the other end of the spectrum. At 11.5 c€/kWh, the average retail price for industrial customers in the EU27 in the reference period fell by 4% compared to Q2 2019.

Figure 49 – Household Electricity Prices, second quarter of 2020



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

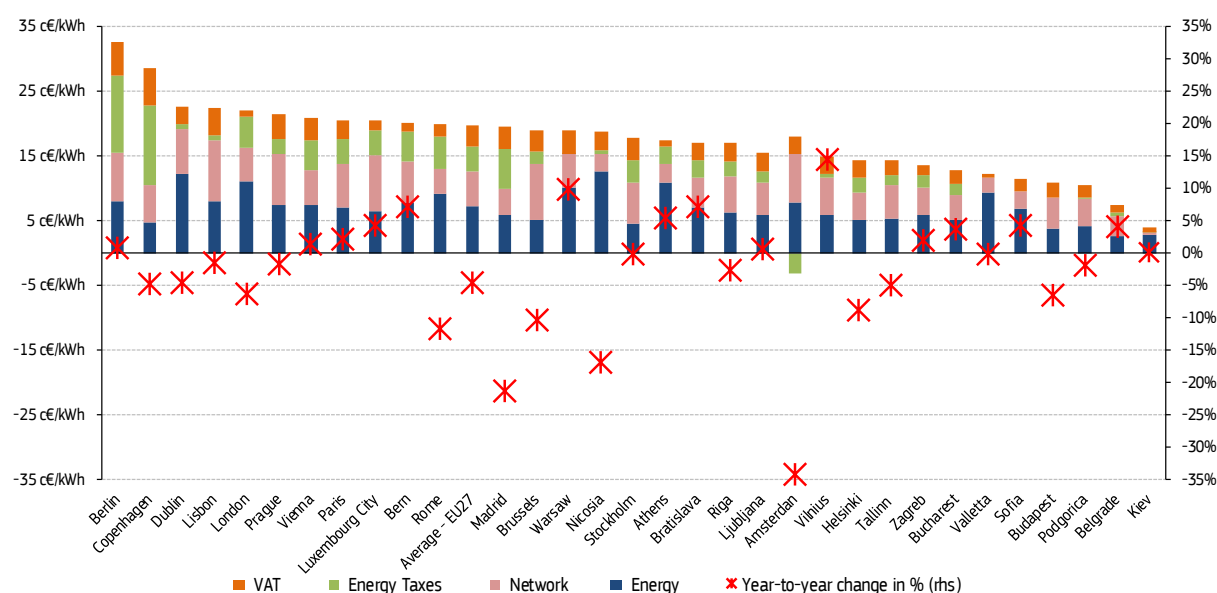
Figure 50 – Industrial Electricity Prices, second quarter of 2020



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

- **Figure 51** shows retail electricity prices for representative household consumers in European capital cities and their composition divided into four categories (energy, network charges, energy taxes and the value added tax). In June 2020, the highest prices were observed in Berlin and Copenhagen (32.6 and 28.6 c€/kWh, respectively) where energy taxes accounted for more than a third of the final bill. However, whereas prices kept rising in Berlin during the last 12 months, they started climbing down in Copenhagen, bringing the two most expensive cities further apart. The lowest prices of EU27 capitals were recorded in Budapest and Sofia (10.9 c€/kWh and 11.6 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 46**. The population-weighted EU27 average declined by 4% year-on-year to 19.7 c€/kWh. Non-Member States in Europe's east tend to have lower prices. Thus, electricity for an average household in Kiev is eight times cheaper than for one in Berlin.
- The highest levels of the energy component in Europe were reported from Nicosia, Dublin and London (11-13 c€/kWh), cities surrounded by wholesale markets with higher prices compared to the EU27 average. The lowest levels of the energy component (4-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Bucharest) or with a high degree of renewable generation (Copenhagen, Stockholm). The EU27 average for the energy component was 7.2 c€/kWh (down from 7.6 c€/kWh in June 2019). The general decrease in European wholesale prices witnessed over the last 18 months has started to be channelled into retail prices. This could be explained by the fact that retailers usually buy electricity in advance before it is sold to customers, which results in a time lag between developments in wholesale and retail markets (see **Figure 11**).
- The highest network charges were recorded in Lisbon (9.5 c€/kWh), Brussels and Luxembourg City (both 8.7 c€/kWh) where they accounted for more than 40% of the total price and were measurably higher than the energy component. The lowest network fees were collected in Valletta (2.4 c€/kWh) and Sofia (2.7 c€/kWh). The EU27 average in the reference quarter was 5.6 c€/kWh (unchanged from June 2019).
- Apart from Berlin and Copenhagen (11-13 c€/kWh), the highest energy taxes were paid by households in Madrid and Rome (5.0-6.5 c€/kWh). Valletta, Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by local authorities. The average energy tax component reached 3.9 c€/kWh (down by 8% from June 2019 mainly thanks to the influence of negative taxation in Amsterdam). Varied VAT rates applied to electricity, ranging from 5% in Malta to 27% in Hungary, also contribute to differences in household prices across Europe.
- The tax reduction subcomponent (tax credit) that applies to electricity customers in the Netherlands was significantly increased as of January 2020 (by more than €200 annually) and is now 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 46**.

Figure 51 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, March 2020

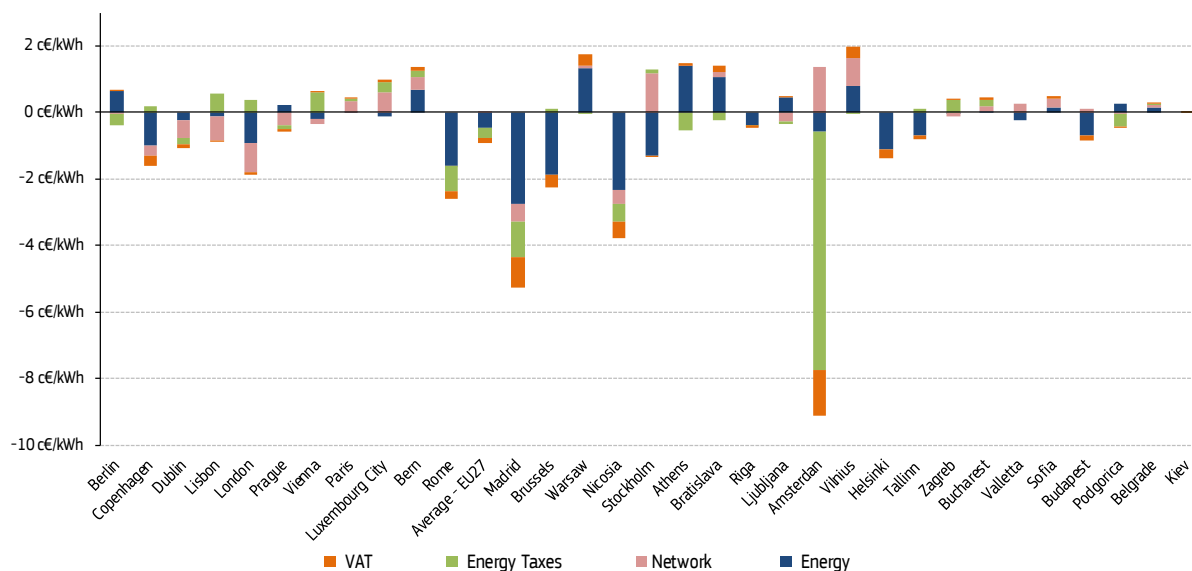


Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in June 2020 were observed in Vilnius (+15%) and Warsaw (+10%). As shown in **Figure 52**, the distribution component was the biggest contributor to rising prices in Vilnius. In Warsaw, rising prices were driven by the energy component. 15 of the EU27

capitals reported prices lower or unchanged compared to the same month of the previous year, with Amsterdam (-34%), Madrid (-21%) and Nicosia (-17%) posting the largest drops. The price fall in the Dutch capital was driven mainly by a substantially raised tax credit (see previous figure), whereas households in the Cypriot capital benefited mainly from lower prices of the energy component. In Madrid, all components contributed to a decrease in the retail price for residents.

Figure 52 – Year-on-year change in electricity prices by cost components in the European capital cities comparing March 2020 with March 2019

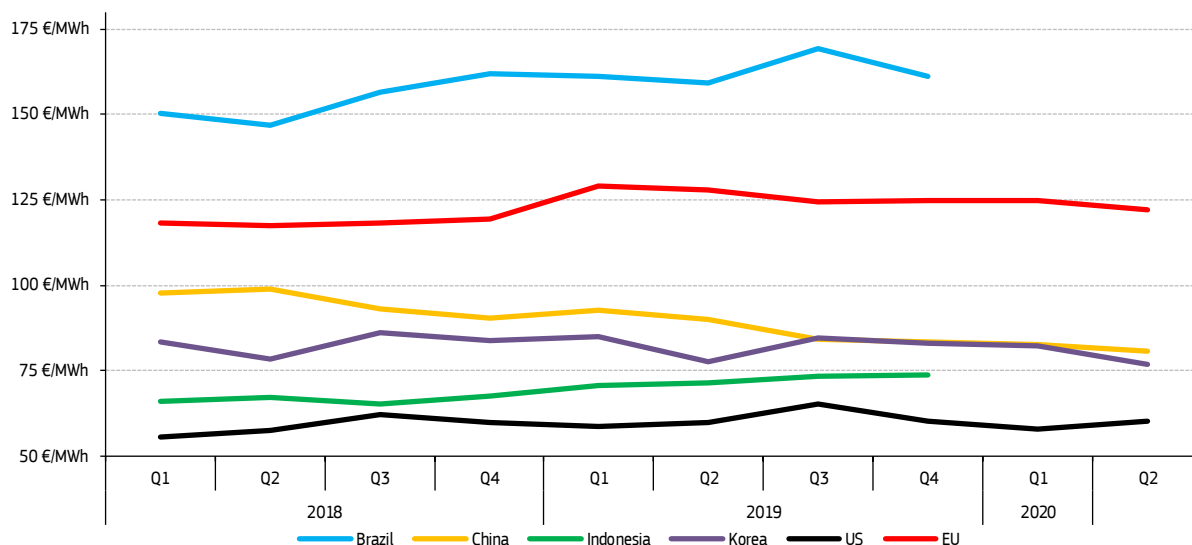


Source: Vaasaett

5.2 International comparison of retail electricity prices

- **Figure 53** displays industrial retail prices paid by consumers in the EU27 and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.
- Electricity prices for industrial users in the EU27 fell by 2% in Q2 2020 compared to the previous quarter. A similar decrease occurred in China. South Korean industrial prices registered a steeper decrease (by 7% quarter-to-quarter) and fell under the Chinese level. Industrial electricity prices in the United States, on the other hand, rose by 4% quarter-to-quarter in euro terms.

Figure 53 – Retail electricity prices paid by industrial customers in the EU27 and its main trading partners



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

Glossary

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

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

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

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

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

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

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

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

EPS is a consumption-weighted baseload benchmark of 5 most advanced markets offering a 3-year visibility into the future. Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices are rolled over towards the end of each year, meaning that the year-ahead benchmark in 2018 shows the price for 2019; and the year-ahead curve in 2019, in turn, shows baseload prices for delivery in 2020.

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

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

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

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

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

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

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

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

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

