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Quarterly Report on European Electricity Markets

with special focus on the impact of the pandemic

Market Observatory for Energy

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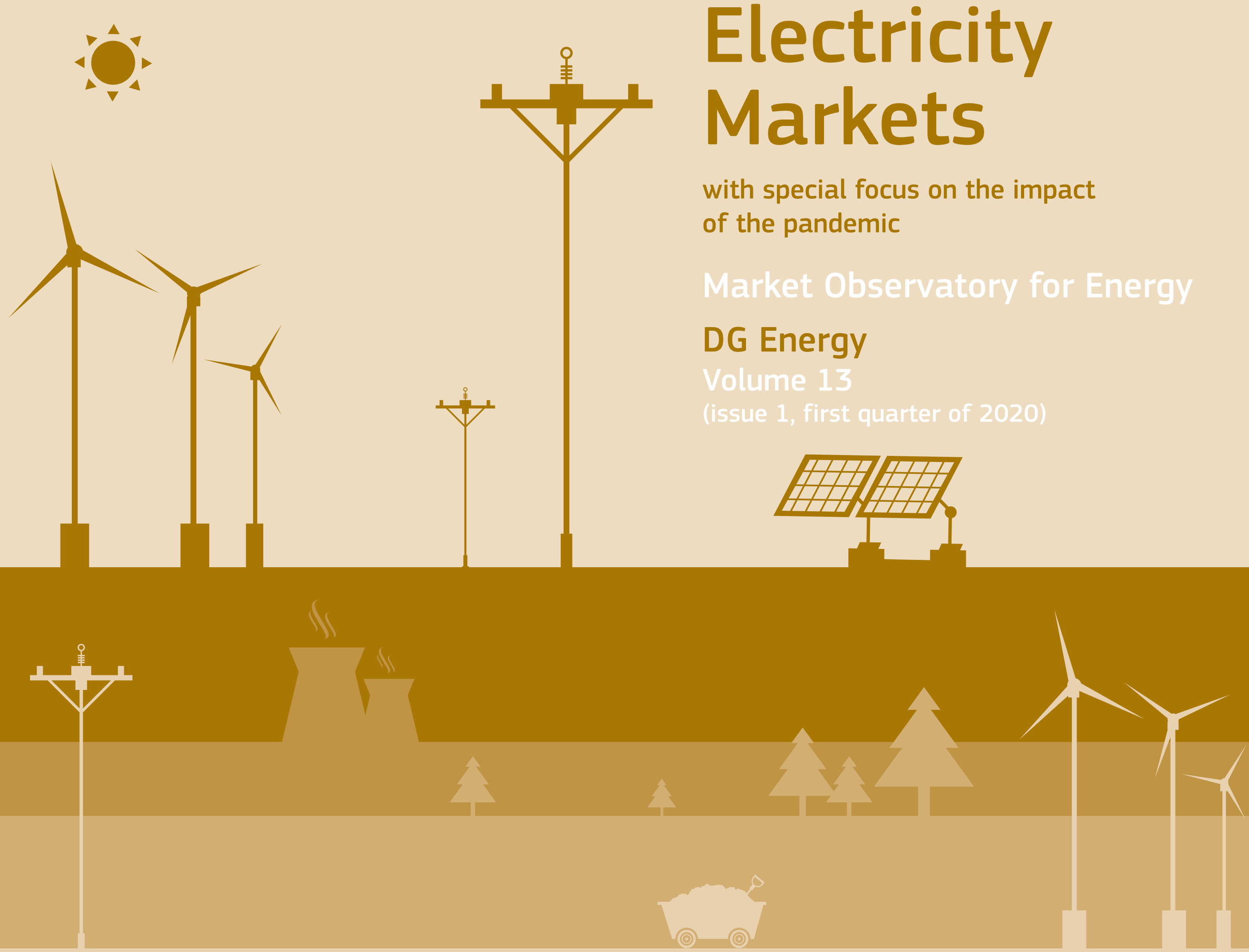

Energy

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CONTENT

HIGHLIGHTS OF THE REPORT

- **Despite affecting directly the EU electricity system for only a few weeks in March, the long shadow of the global health crisis hangs over the results of the whole first quarter 2020. Combined with the effect of a very warm and windy winter, the widespread lockdown measures imposed to slow down the spreading of the coronavirus reduced electricity consumption in the EU27 by 3% year-on-year, surpassing the estimated contraction in economic activity during Q1 2020. Demand destruction reached its peak in April, after which a gradual recovery begun. However, consumption still remains measurably below pre-crisis levels on average. The demand shocks observed in Italy, France and Spain during the quarantine period were unprecedented both in scale and duration.**

- **The first quarter witnessed dramatic changes in the structure of the EU27 power mix. Fossil fuels were caught in the pincer movement of falling demand and rising renewables. Coal generation bore the brunt of the pressure, falling by 30% year-on-year (-38 TWh). Gas was unable to capitalize on coal's demise and suffered losses as well (-3 TWh). Coal-to-gas switching quickly gave way to a wide grey-to-green shift. Thanks to recovering hydro output and record high wind generation, renewable energy sources had a very successful quarter, expanding by 38 TWh year-on-year and reaching a 40% share in the power mix, their highest quarterly figure to date. Not even nuclear energy was spared by the weakening demand and rock-bottom wholesale prices. Reactors in Sweden, France and other countries had to be taken offline or significantly ramped down. All in all, renewable generators were the least affected by the crisis and came out of it relatively unscathed.**

- **The shift away from fossil fuels caused the carbon footprint of electricity generation in the EU27 to decrease by 20% year-on-year in the first quarter, according to preliminary estimates. As the decarbonisation drive continued and even intensified in April and May, the power sector seems to be on track for another double-digit decrease in CO2 emissions in 2020, after a 15% annual drop in 2019.**

- **The COVID-19 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. TSOs and market participants were also forced to adapt to unpredictable changes in the daily routines of hundreds of millions of Europeans who found themselves quarantined in their homes. Overall, networks coped with the crisis well and proved their ability to handle increased levels of renewable penetration. But this experience, which involved a substantial increase in the occurrence of negative prices, points to the need for increased flexibility of the electricity system, both on the supply and demand side. In this respect, the lockdown period, which saw instances of renewables surpassing 50% of the total EU-wide generation, could be seen as a precursor of things to come and an opportune moment to evaluate and plan for a future that might not be as distant as previously thought.**

- **As a result of falling demand and rising renewable generation, day-ahead electricity prices plunged across the continent, bottoming out in April at all-time lows. The decline in forward prices, which form an important component of retail prices, was much less pronounced. At the end of May 2020, baseload power for year-ahead delivery in major European markets settled some 5-7 €/MWh (roughly 10-15%) lower than in 2019. While in the past two years the market expected wholesale prices to generally fall in the future due to higher renewable penetration, this has reversed lately. Prices are expected to climb up on the back of the recovery.**

- **The repercussions of the falling demand go beyond the immediately visible effects such as power prices or the structure of the mix. In many Member States consumption influences utilities' regulated income and, hence, network costs. The amount of consumed electricity very often serves as the basis for the calculation of renewable surcharges. Lower consumption thus means higher distribution costs or green charges per each consumed MWh. Therefore, the ultimate consequences of the pandemic for various stakeholders are expected to be revealed and analysed only gradually and with some delay.**

- **Demand for electrically chargeable passenger vehicles (ECVs) continued to grow robustly. New ECV registrations in the EU27 doubled in Q1 2020 year-on-year to 167,000 vehicles. Rising interest in cleaner mobility coincided with a sharp fall in the sales of diesel and petrol cars and drove the market share of ECVs to record 6.8%. Almost 25,000 new public charging points were added EU-wide in the first three months of 2020. With this fast tempo of expansion (as compared to the past), the development of charging infrastructure has on average kept pace with rapidly rising ECV sales.**

EXECUTIVE SUMMARY

- Electricity consumption in the EU27 declined by approximately 3% year-on-year in Q1 2020, dragged down by warm winter conditions and covid-related measures restricting social and economic activity. Compared to the same quarter last year, power demand decreased in all major economies, starting with France (-5.4%), where the impact of the mild winter was the most powerful, and Italy (-4.5%), where the effects of the pandemic were felt earlier than elsewhere. Declines were registered also in Poland (-4.3%), Spain (-3.0%), Germany (-2.4%) and the Netherlands (-0.8%). Rising consumption levels were reported from Hungary, Ireland and Bulgaria. EU-wide, the reference quarter had 2.7 °C higher temperatures than usual per day, an exceptionally high figure.

- Prices of coal and gas went down in the reference period compared to the previous quarter, but the fall in gas contracts, both spot and on the forward curve, was twice as large as in the case of coal. This boosted the advantage of gas vis-à-vis its dirtier competitor in the generation mix and contributed to the continued decline in coal-fired electricity generation. The average TTF spot price reached 9.7 €/MWh and the average CIF ARA spot price was assessed at 44.1 €/t in Q1 2020. Year-ahead prices for both commodities declined to a lower extent than their spot peers.

- 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. However, by the end of May, the carbon market managed to recoup nearly all of the losses suffered during the most acute phase of the pandemic. The average CO_2 spot price in Q1 2020 fell by 8% compared to Q4 2019 to 23 €/t. In April and May 2020, the average CO_2 spot price reached 20 €/t. In June 2020, it rose to 23.5 €/t and was back at pre-crisis levels.

- Highlighting the decline of coal in the European power sector, thermal coal imports into the EU27 plunged by 47% year-on-year to 14.7 Mt in Q1 2020. The fall was especially severe in February and March as high renewable generation, the onset of the covid-related restrictions and adverse conditions for coal-fired generation drastically reduced coal burn. The estimated EU27 import bill for thermal coal amounted to €1 billion in Q1 2020, down 57% compared to Q1 2019.

- The structure of generation in the reference quarter was influenced mainly by high renewable presence and falling demand, 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 38% in Q1 2019 to 33% in Q1 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 25% year-on-year (or 15 TWh), while hard coal-fired generation plunged by 35% year-on-year (or 23 TWh) in Q1 2020. Less CO_2-intensive gas generation saw its share of the mix unchanged at 20% in the reference quarter, but lost 3 TWh in absolute terms year-on-year.

- The share of renewables (hydro, biomass, wind and solar) jumped from 34% to 40% year-on-year during Q1 2020. The main drivers behind the increased presence of renewable power were very good volumes of hydro sources (up 17 TWh thanks mainly to increases in France, Italy and on the Iberian Peninsula) and record high wind output, which in its onshore segment expanded by 17% year-on-year (or 17 TWh) and in the offshore sector surged by 43% year-on-year (or 4 TWh). Solar-based generation in Q1 2020 grew by 15% (or 3 TWh) compared to Q1 2019. Generation based on biomass burning experienced stagnation.

- The European Power Benchmark of nine major markets averaged 30 €/MWh in the reference quarter, down 28% compared to the previous quarter. The cheapest baseload power prices were observed in the Nordic region. Even though wholesale prices were falling across different regional markets in Q1 2020, divergence levels increased considerably as the decline in prices in countries and regions that traditionally have cheaper electricity was greater than in markets where wholesale prices are typically higher. Sharp and sudden price drops drove traded volumes to the highest quarterly level on record.

- At 421, the number of hours with negative wholesale prices in Q1 2020 was a third higher in the observed bidding zones than in the previous Q1. The highest number of falls into negative territory in the reference quarter was concentrated in February due to extreme wind speeds in Western Europe.

- The average retail price for a mid-sized household in the EU27 decreased by 1% year-on-year in the reference quarter. The largest year-on-year rises in the household category were assessed in Poland and Lithuania (+14%), followed by France (+11%). The biggest year-on-year falls were estimated for the Netherlands (-38% due to a significantly increased tax credit applicable to all households) and Slovenia (-26%).

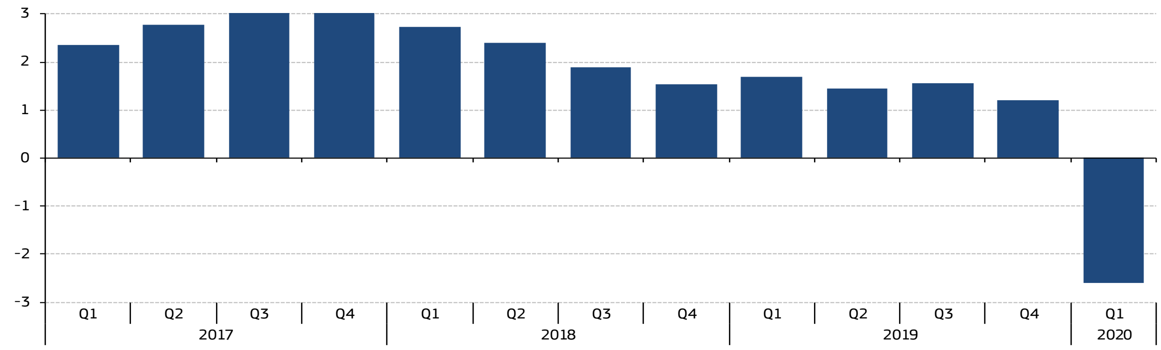
- The withdrawal agreement between the United Kingdom and the EU entered into force on 1 February 2020 (CET). As of the current report, EU aggregates do not include the UK and, hence, might differ from similar aggregates published in earlier editions of the report. However, being an important export destination for continental electricity generators, the UK market is still analysed in the report.

1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the containment measures imposed mostly towards the end of Q1 2020 to combat the spreading of the coronavirus ended abruptly the economic expansion of the last seven years and drove most European economies into contraction. According to an estimate published by Eurostat in June, seasonally adjusted GDP in the EU27 shrank by 2.6% year-on-year between January and March 2020. This was the sharpest decline since the global financial crisis in 2008-2009. An even sharper fall is expected for Q2 2020 when the full impact of lockdown restrictions was felt. Growth remained in positive territory only in Bulgaria, Ireland, Romania and Sweden. The highest declines were reported in France, Italy and Spain.

Figure 1 – EU27 GDP annual change (%)

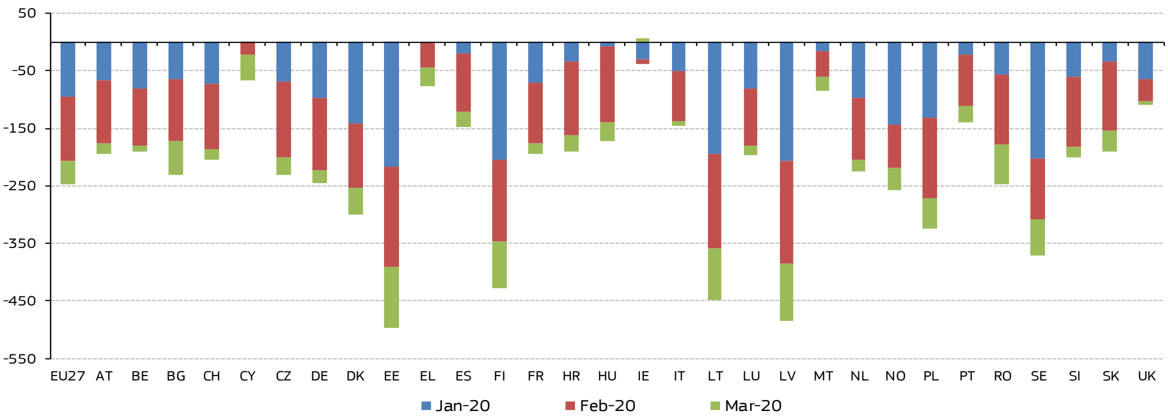


Source: Eurostat

- According to Eurostat figures and TSO data, the consumption of electricity in the EU27 fell by 3.2% year-on-year in Q1 2020, driven down by warm weather in the first half of the reference period and the onset of covid-related restrictions on economic and social activity in March. 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. Compared to the same quarter last year, power demand decreased in all larger economies, starting with France (-5.4%) where the impact of above-average temperatures was the most powerful. Then came Italy (-4.5%) where the effects of the pandemic were felt earlier than elsewhere. Declines were registered also in Poland (-4.3%), Spain (-3.0%), Germany (-2.4%), and the Netherlands (-0.8%). Rising consumption levels were reported from Hungary, Ireland and Bulgaria in Q1 2020.

- **Figure 2** illustrates the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average in Q1 2020. EU-wide, the quarter had 247 HDDs below average, which translates into 2.7 °C higher temperature than usual per day, an exceptionally high figure. Very mild weather was observed especially in January and February. Higher-than-usual temperatures were measured in all Member States, with the highest deviations observed in the northern part of the continent. Finland, Sweden and the Baltic states witnessed more than 350 HDDs below the normal, which means that every day was on average nearly 4 °C warmer than usual on their territory. This resulted in lower heating-related demand and depressed wholesale electricity prices in the Nord Pool market. No European country experienced colder temperatures than usual during the reference quarter. Ireland witnessed climate conditions that were nearest to a long-term normal.

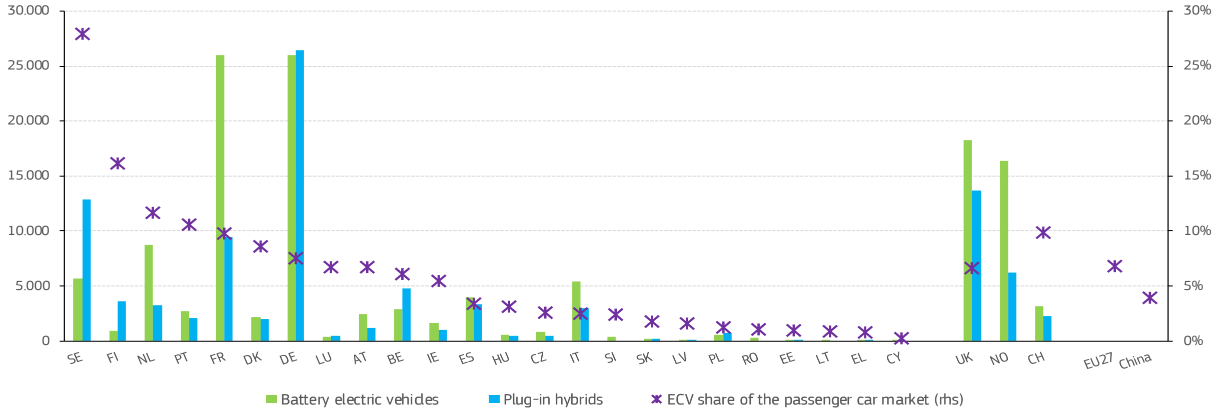
Figure 2 - Deviation of actual heating degree days from the long-term average in January-March 2020



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

- **Figure 3** shows that demand for electrically chargeable passenger vehicles (ECVs) in European countries remained robust in the first three months of 2020 despite the health crisis. New ECV registrations in the EU27 more than doubled (+100.7%) in the reference quarter, totalling 167,000 vehicles amid a large roll-out of new models and proliferating government support policies. Both the battery-electric (BEV) and plug-in hybrid (PHEV) segments contributed to the result (+68% and +162% respectively). Growing interest in cleaner mobility coincided with a sharp fall in sales of diesel and petrol cars and drove the market share of ECVs to record 6.8% in Q1 2020 (from 2.5% in Q1 2019), compared to less than 3.8% in China. The highest ECV penetration was observed in Sweden where one in four new passenger cars sold could be plugged. Finland came in second with a 16% ECV share, followed by the Netherlands, Portugal and France. Germany became the largest individual market in absolute terms with more than 50,000 newly registered ECVs. ECV penetration rose considerably even in Member States where sales of petrol and diesel cars traditionally dominated. In Czechia, new ECV registrations quintupled year-on-year in the reference quarter.

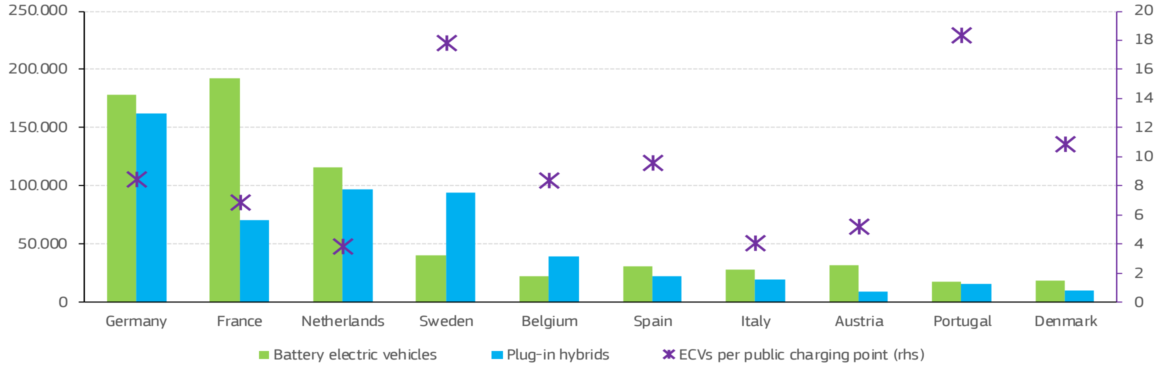
Figure 3 – Electrically chargeable passenger vehicle (ECV) registrations in selected countries in Q1 2020



Source: ACEA, CPCA

- **Figure 4** looks at ten Member States with largest ECV fleets and shows that despite the rapid growth in sales, the total amount of ECVs on European roads still remains modest. The largest fleet of battery electric vehicles is registered in France. Nearly 200,000 BEVs connected to the grid each day translate into approximately 0.5 TWh of additional power demand annually, a negligible amount in the dimensions of the total national consumption. Buyers of passenger BEVs in France have benefited from a maximum purchase subsidy of €6,000, which is to be temporarily increased to €7,000 from June as part of a stimulus package for the automotive industry. The maximum direct subsidy was increased also in Germany where up to €9,000 in the case of cheaper ECVs is granted. Nearly 150 models of either battery electric vehicles or plug-in hybrids were available to consumers across Europe in Q1 2020, a 50% increase compared to the beginning of last year. Diverging rates of investment in public charging infrastructure mean that there are large differences in the number of charging points available to ECV drivers on average at public premises. EU-wide, almost 25,000 new charging points were added in the first three months of 2020, a fast tempo of expansion in the historical perspective. This pushed the average number of registered ECVs per charging point to 6.8 (compared to 7 at the end of 2019) and testifies to the fact that the development of charging infrastructure has on average kept pace with rapidly rising ECV sales. Fast charging points recorded even higher growth rates in Q1 2020 and increased their share in the total number of charging points to 9.5% (from 9.1% at the end of 2019).

Figure 4 – Member States with largest passenger ECV fleets by the end of Q1 2020

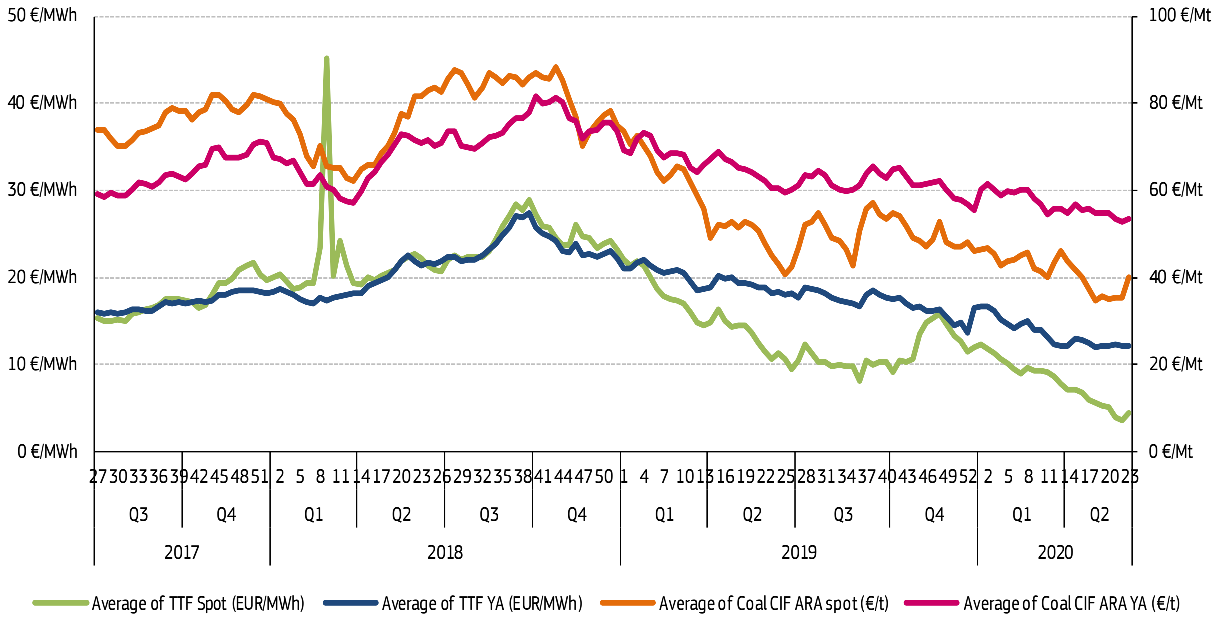


Source: European Alternative Fuels Observatory

1.2 Supply side factors

- **Figure 5** reports on the developments in European coal and gas prices. Prices of both commodities went down in the reference period compared to the previous quarter, but the fall in gas contracts, both spot and on the forward curve, was twice as large as in the case of coal. This boosted the advantage of gas vis-à-vis its dirtier competitor in the generation mix and contributed to the continued decline in coal-fired electricity generation. Year-ahead prices for both commodities decreased to a lower extent than their spot peers, deepening their contango position in relation to the spot market, which they entered at the start of 2019.
- Spot gas prices (represented by the TTF day-ahead contract) were on a downward trajectory during most of Q1 2020 on the back of mild winter weather in the first weeks of the year, high wind output in February and the onset of lockdown measures in March, all of which materially curbed gas demand. The market remained well supplied during the entire reference period thanks to plentiful pipeline and LNG deliveries and record high storage levels. Overall, the average quarterly TTF spot price reached 9.7 €/MWh in Q1 2020 (down 23% compared to Q4 2019 and down 47% compared to Q1 2019).[1] Spot gas prices continued to slide and fell to record low levels in April and May as the winter ended with storage facilities still 60% full and the regular spring maintenance at various North Sea gas terminals, fields and processing plants was postponed due to the pandemic.
- Thermal coal spot prices, represented by the CIF ARA contract, were being kept under pressure by their gas peers in the reference quarter amid high stockpiles at main port terminals and low demand from generators. The average quarterly CIF ARA spot price was assessed at 44.1 €/t in Q1 2020 (down 12% compared to Q4 2019, and down 33% compared to Q1 2019). Spot coal prices fell even lower in April and May, after the onset of covid-related restrictions significantly curbed coal firing.
- Year-ahead gas prices continued followed their spot peers in Q1 2020 and, at 14.4 €/MWh, were trading on average 11% lower than in the previous quarter. The combination of plentiful LNG deliveries expected this year and stocks levels remaining high after the winter has weighed on the longer-term market. Meanwhile, year-ahead CIF ARA contracts were heading lower as well, albeit at a slower pace, as it seemed that the technical potential for further coal-to-gas switching in Europe was almost exhausted.

Figure 5 – Weekly evolution of spot and year-ahead coal and gas prices



Source: S&P Global Platts

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

- The market for emission allowances, shown in **Figure 6,** 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. But by the end of May, the carbon market managed to recoup nearly all of the losses suffered during the most acute phase of the pandemic.

- CO2 prices started the year 2020 by continuing to follow a downward trajectory they embarked on since the autumn 2019, on the back of warm weather conditions, strong wind output and expectations of a release of the UK allowances not auctioned or allocated in 2019. The general trend was interrupted by two brief rallies. In the middle of January, the market was buoyed by speculations that some of the allowances destined for auctions but not needed due to the German coal exit might be cancelled. A second surge came a month later as prices below 23 €/t revived the interest of bargain hunters. The quickly spreading lockdown measures in the middle of March stunned the market and sent prices to a two-year low amid thin volumes and cancelled auctions. The sharp fall was driven by the prospect of a significantly drop in carbon emissions due to restrictions on economic activity and by a fear that some industrial market participants might resort to selling their allocation in order to raise capital at a time of financial distress. However, prices quickly rebounded 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.

- All in all, the average quarterly CO2 spot price in Q1 2020 fell by 8% compared to Q4 2019, a second quarter-to-quarter decline in a row. At 23 €/t, the average price of one allowance in the reference quarter was 3% higher compared to the same quarter a year ago. In April and May 2020, the average CO2 spot price reached 20 €/t.

- The Withdrawal Agreement between the EU and the UK, ratified at the end of January, established that British operators are to abide by the EU ETS compliance obligations for 2019 and 2020. This has allowed British authorities to resume the issuing of 2019 free allocation in February and to restart the auctioning of allowances in March. The UK government is currently planning to establish a national emissions trading system. It has expressed its willingness to link this system to the EU ETS.

Figure 6 – Evolution of emission allowance spot prices from 2018

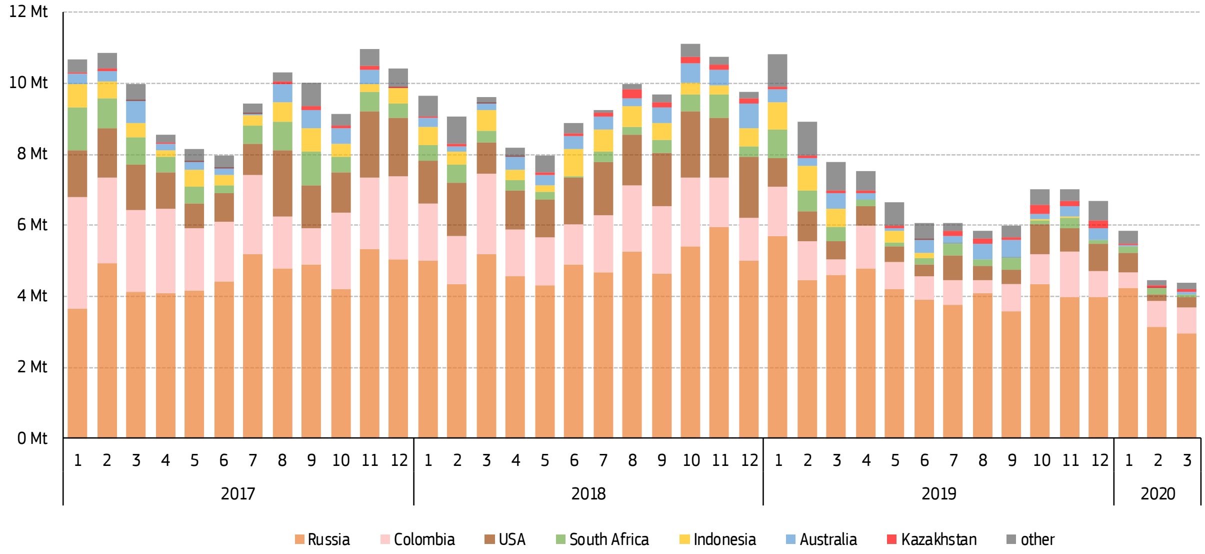
Source: S&P Global Platts

- **Figure 7** shows that thermal coal imports into the EU27 plunged by 47% year-on-year to 14.7 Mt in Q1 2020. The fall was especially severe in February and March as high renewable generation, the onset of the covid-related restrictions on economic activities and adverse conditions for coal-fired generation drastically reduced coal burn (see **Figure 8, Figure 26**). The estimated EU27 import bill for thermal coal amounted to €1 billion in the reference period, 57% lower compared to Q1 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 70% of the total in the reference quarter. Russian traders now clearly dominate the rapidly shrinking European thermal coal market, as most of their rivals are unable to compete in the though low-price, low-demand environment. Only Colombia was able to retain most of its market share (13%) compared to the previous quarter. The position of the United States worsened as its share shrank to 7% in Q1 2020 (compared to 11% in Q4 2019). South Africa accounted for 3% of EU's thermal coal imports in the reference period. Deliveries from other trading partners were insignificant.

- The year-on-year decline in thermal coal shipments in Q1 2020 could be observed in all major EU importers. Deliveries to German, Belgian and Dutch terminals (calculated together as part of one supply chain feeding German and Dutch power plants) fell by 41% year-on-year to 8.2 Mt amid low demand in Western Europe. Polish terminals also saw shipments declining significantly in Q1 2020 (-41% year-on-year to 2.2 Mt) after local utilities curbed Russian imports. In the rest of the major markets, low coal generation significantly reduced imports, with Italy registering 1.2 Mt of deliveries (-41% year-on-year), France 1.0 Mt (-31% year-on-year) and Spain 1.0 Mt (-73% year-on-year).

Figure 7 – Extra-EU thermal coal import sources and monthly imported quantities in the EU27

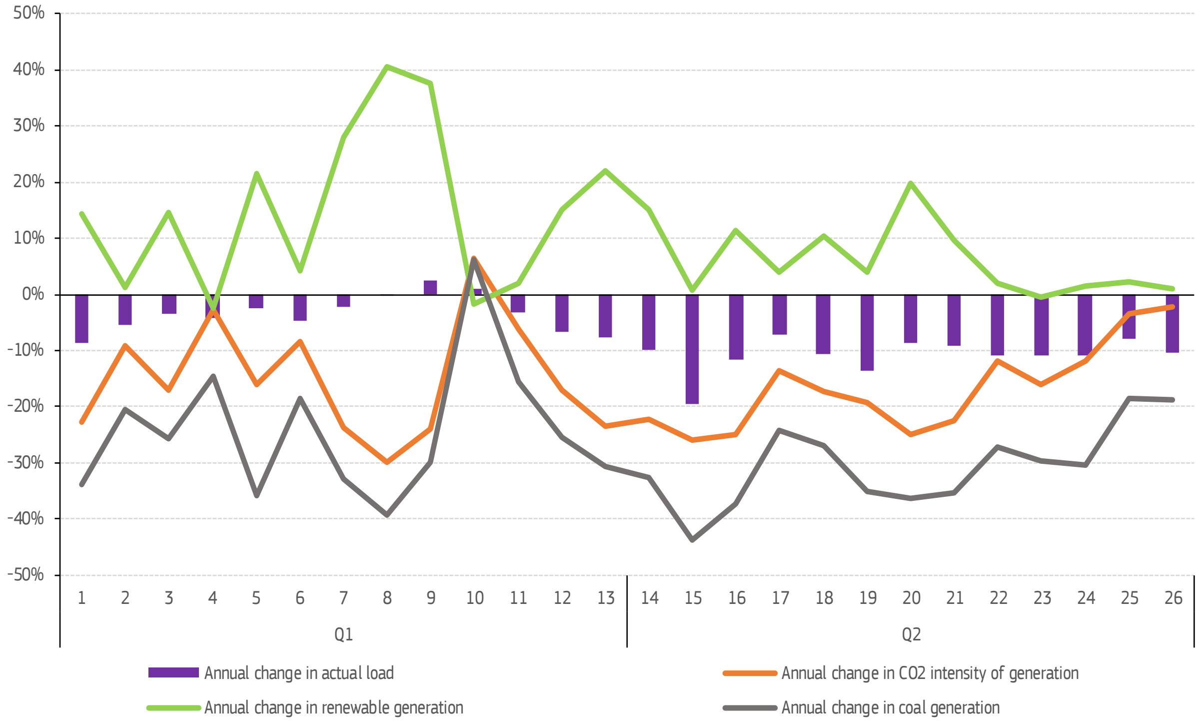


Source: Eurostat.

2 Focus on the impacts of the COVID-19 pandemic

- **Figure 8** shows changes in weekly actual load (a proxy for power demand), renewable and coal generation and CO2 intensity of the European power mix between 2019 and 2020. During most of the reference quarter, the carbon footprint of electricity generation was significantly lower than in the same period last year due to lower demand and higher renewable generation, both of which reduced runtimes of coal- and gas-fired power plants. The only exception was the beginning of March when a cold spell drove electricity consumption up and a limited availability of renewable sources opened more space for fossil fuels in the merit order. For the whole Q1 2020, the power sector's CO2 emissions in the EU27 were estimated to fall by 20% compared to the same quarter a year before. As the decarbonisation trend continued and even strengthened in April and May, the EU power sector was on track for another double-digit decrease in carbon emissions in 2020, after a 15% annual drop in 2019. **Figure 8** also demonstrates that the trough in power demand was reached in April around Easter, when the full force of lockdown measures was at its height. Even with most restrictions lifted, power demand across Europe was still considerably lagging behind last year's levels in June (by approximately 9%, compared to a 10% gap in May).

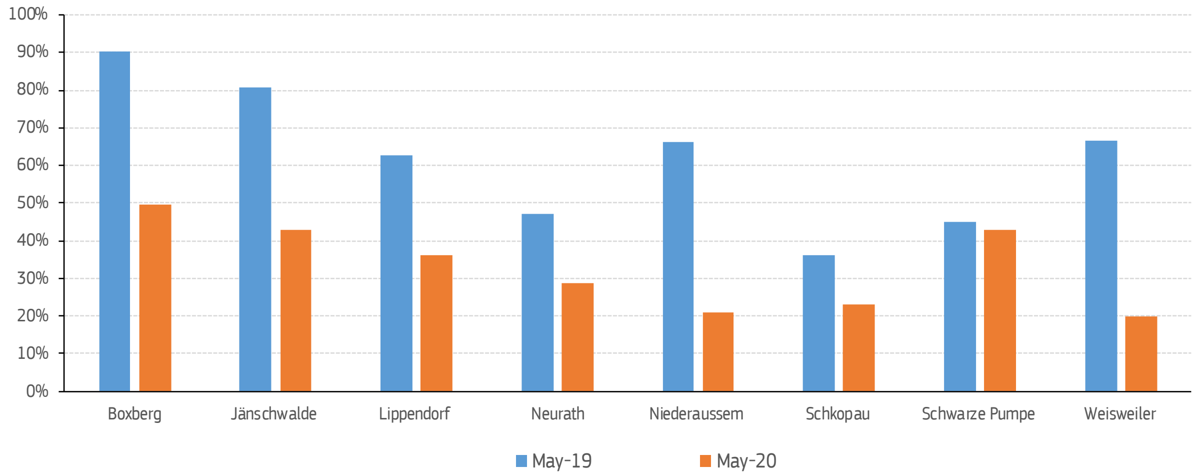
Figure 8 – Weekly development of annual changes in actual load, renewable and coal generation and CO2 intensity of the European power mix in 2020



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

- The pandemic has accelerated the decline of coal in the European power sector. Already struggling to remain competitive in 2019 due to low gas prices, pricier carbon allowances and rising RES penetration, coal power plants across the continent are coming under even greater pressure this year. Two main factors contribute to this trend. First, falling electricity consumption is pushing the least competitive sources out of the merit order and that under current conditions means less coal in the mix. In Q1 2020, coal and lignite generation in the EU27 declined by 30% year-on-year. The collapse deepened in April and May as lockdown restrictions multiplied and dented demand levels. Power demand is expected to recover eventually but by that time rising renewable generation will have prevented coal from clawing back its place in the merit order again. Second, record low gas prices mean that coal is now at an even greater disadvantage to its less CO2-intensive rival. In fact, spot gas prices fell so low at times this year that they made the least efficient gas plants more competitive than the most efficient lignite plants. In May, 11 out of 29 active lignite blocks in Germany were mostly idle, with seven of these blocks seeing no action at all. As shown in **Figure 9**, no lignite power plant reached more than 50% utilization rate in May, which is significant in view of the fact that these generators were long considered to be providers of baseload power. This development has been helped by the fact that the carbon market withstood the pandemic and continues to favour cleaner alternatives to coal. Several announcements of accelerated plant closures or abandoned new projects (Ostroleka C in Poland) confirm the persisting deterioration of coal's position in the European power sector.

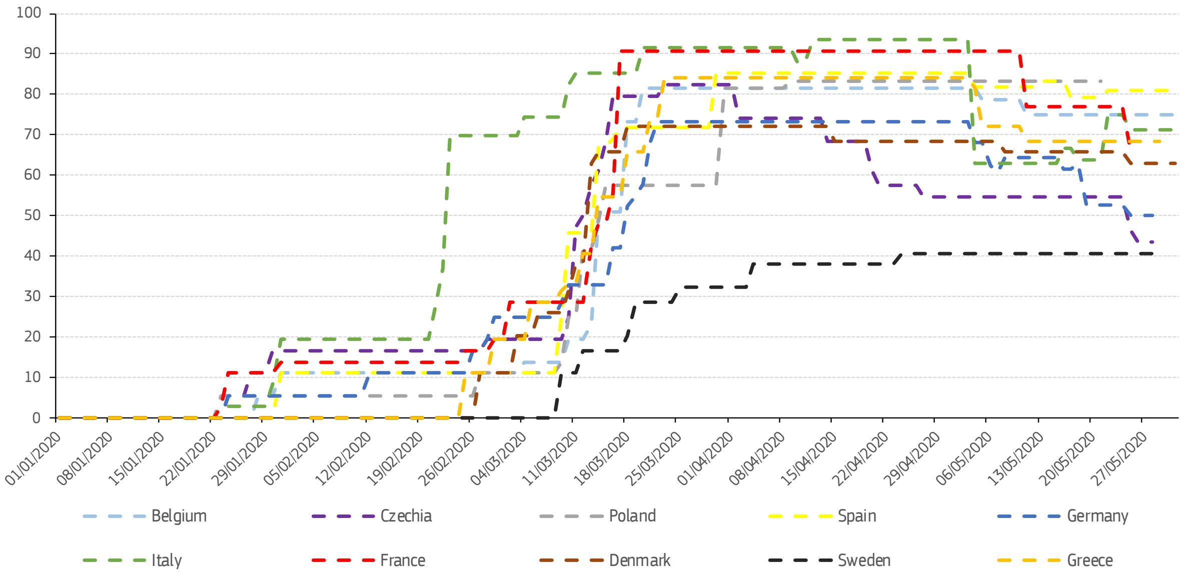
Figure 9 – Changes in utilization rates of German lignite power plants



Source: ENTSO-E. Each plant contains several blocks

- In order to visualize the different government approaches towards the pandemic, a composite measure based on nine response indicators including school closures, workplace limitations, and travel bans, rescaled to a value from 0 to 100, was designed by Oxford University's Blavatnik School of Government. The index, reproduced in **Figure 10** for selected Member States, shows that the severity of restrictions quickly escalated in the second half of March and mostly culminated in April. Italy, where the coronavirus began to spread earlier than in the rest of Europe, tightened the measures ahead of other governments. Less stringent initial response was observed in Sweden.

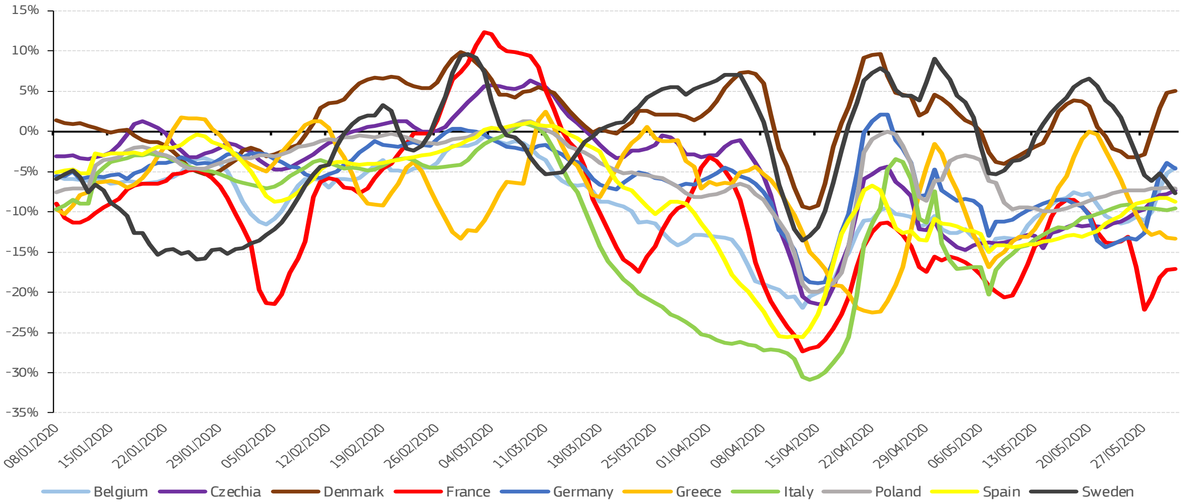
Figure 10 – Government Response Stringency Index for selected Member States



Source: Oxford COVID-19 Government Response Tracker

- **Figure 11** illustrates changes in actual load in the same countries as in the previous figure between 2019 and 2020. It demonstrates that since the second half of March, power demand was most affected in Member States with the harshest quarantine measures, especially in Italy, France, Spain, Belgium and Greece where the Government Stringency Index rose above 80 points. Italy experienced the largest fall in electricity consumption, reaching more than 30% during the Easter weekend. In March, Italian power demand fell 10% year-on-year. In April, the gap grew to 17% (18% if adjusted for temperature and calendar differences), before shrinking to 10% in May. Sweden and Denmark, where restrictions on economic activity were less severe, experienced much more limited impacts on electricity consumption. **Figure 11** also points to a partial recovery in power demand in the weeks following the easing of lockdown measures. In some cases, however, the recovery has proved to be unstable and prone to setbacks. All in all, falls in consumption observed in some Member States in 2020 are unprecedented both in scale an duration. During the last major economic crisis in 2008-2009, power demand in France fell by 5% at maximum.

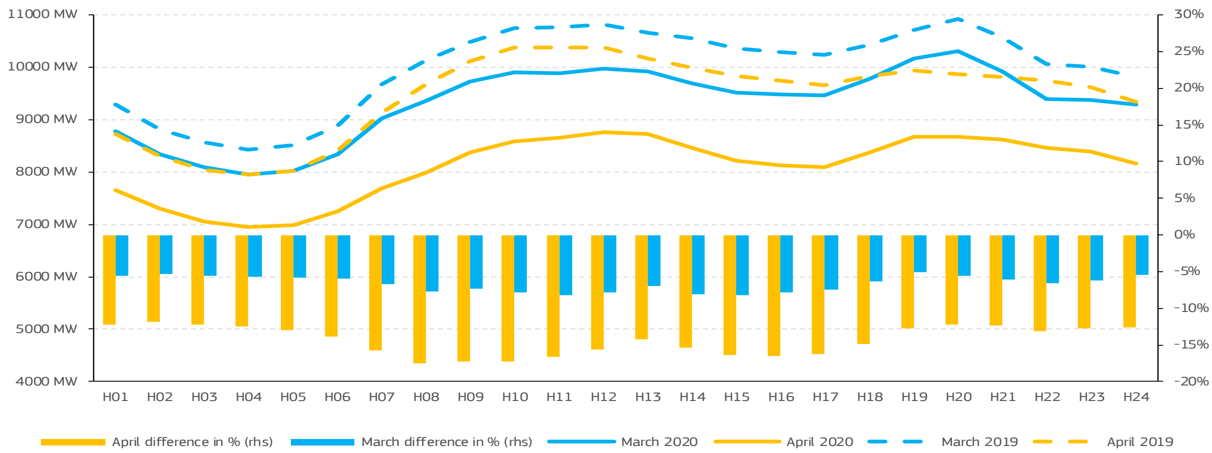
Figure 11 – Annual change in actual load in selected Member States – rolling 7-day average



Source: ENTSO-E

- Lockdowns changed the daily routine of hundreds of millions of Europeans, which in turn affected electricity consumption fluctuations. **Figure 12** illustrates this on the case of Belgium where restrictions on movement were relatively strict, prolonged and widespread. In March, the load in the Belgian network (a proxy for consumption) went down by 7% compared to the same month in the previous year. The difference widened to 14% in April. But a closer look at average load profiles reveals an uneven scale of change throughout the day, which intensified in April. Larger falls in the morning hours suggest a slower start of the day. With no necessity to commute to work, people could sleep longer. Another more pronounced fall in consumption is observable between 3pm and 5pm, suggesting a more relaxed afternoon. The shift in behavioural patterns posed a challenge for those that need to predict electricity consumption – TSOs and traders. Forecasts are generally based on historical records, but the unprecedented scale of the health crisis reduced the predictive power of demand models.

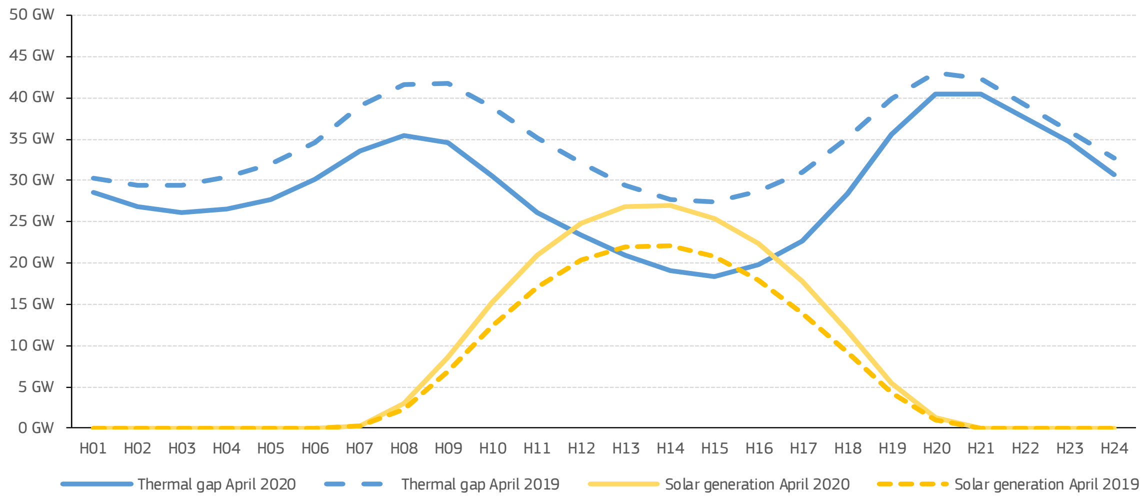
Figure 12 – Average daily load profiles and their annual change in Belgium



Source: ENTSO-E

- Similar effects could be observed in Germany in spite of the fact that the containment measures there did not reach such severity. In the German case, however, changes in power demand patterns coincided with increased renewable generation and produced results which were expected only in several years' time. **Figure 13** demonstrates this using April data. The decrease in power demand, especially pronounced in the morning and afternoon hours, was compounded by increased solar generation, which thrived thanks to sunny weather and expanded PV capacities in the country. As a result, the room left in the merit order for thermal (coal, gas, nuclear) power plants was significantly reduced, most prominently between 9am and 5pm when the thermal gap was 8-9 GW lower compared to April 2019. Thus, the German grid started to resemble other systems with high solar PV penetration such as California or South Australia where duck-shaped thermal gap curves can be observed. The share of solar generation in the German power mix reached 19% in April (up from 15% in the same month a year before). The impact on wholesale power prices far-reaching due to a somewhat limited system flexibility.

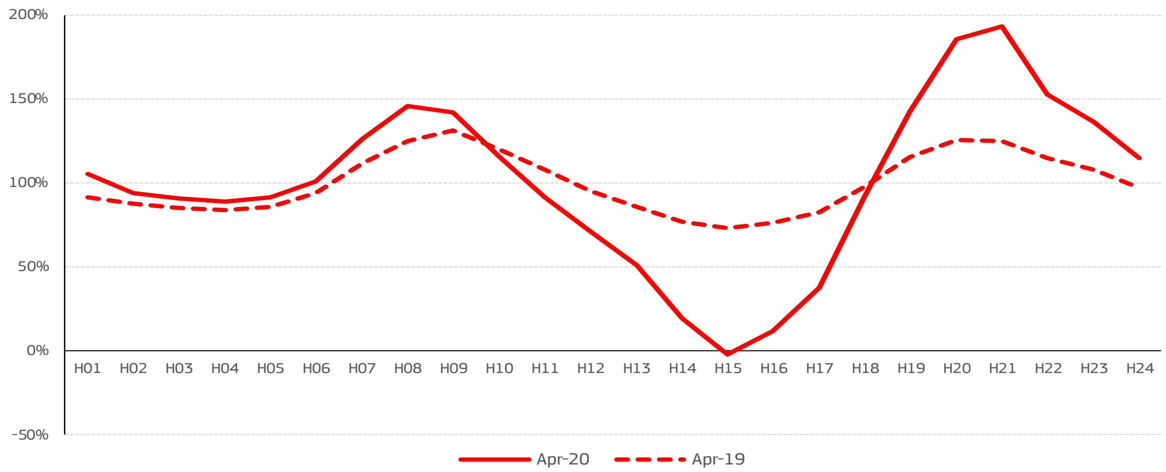
Figure 13 – Average daily thermal gap profiles and solar generation in Germany – the duck curve



Source: ENTSO-E. Thermal gap refers to the difference between the network load and the combined solar and wind generation in an individual hour of the day

- Due to cheaper fuel and curbed demand, German power prices in the day-ahead market in April were about 50% lower year-on-year (at 17 €/MWh). More interesting, however, was the much bigger deviation from the monthly average that occurred during the day compared to last April, as shown in **Figure 14**. The oscillation reached such levels that it ventured into negative territory between 2pm and 3pm (H15), meaning that day-ahead prices were on average below zero during this hour. This unique situation was caused not only by high solar generation but also by an increased number of negative prices occurring during the afternoon hours.

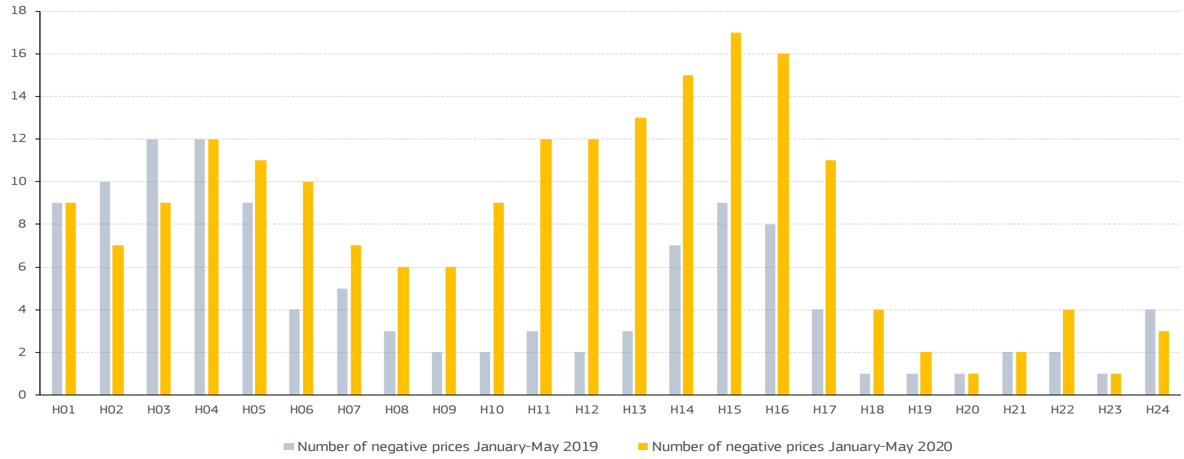
Figure 14 – Average hourly day-ahead prices in Germany in April normalized over the monthly average



Source: ENTSO-E

- **Figure 15** illustrates that instances of negative hourly prices in the German day-ahead market have grown considerably this year but also that the majority of these cases has been concentrated to the afternoon hours, as increased solar generation and depressed demand have left much less room for thermal power plants during this time of day. This represents a shift from past patterns when high wind output and low demand at night were the most common causes of prices diving below zero. An increase in the occurrence of negative prices during the daylight was observable in other markets with rising PV penetration of the grid, such as Belgium, Netherlands and France. This is why peakload prices in all the four markets were lower than baseload prices in April, a rare occurrence. Belgium recorded the lowest hourly price in any April day-ahead auction of -115.31 €/MWh for hour 15 on April 13 (Easter Monday). Several reasons may lie behind the fact that thermal plants continue to be online during periods of negative prices. Some facilities may be bound by contractual obligations (supply for a railway operator or heat deliveries from CHP units requiring electricity to be produced at the same time), other plants may want to capture high prices after sunset and cannot ramp down significantly without wearing out costly plant equipment, or they might be called on by the TSO to support grid stability. Rising occurrences of negative prices point to the need for increased flexibility of the electricity system, both on the supply and the demand side.

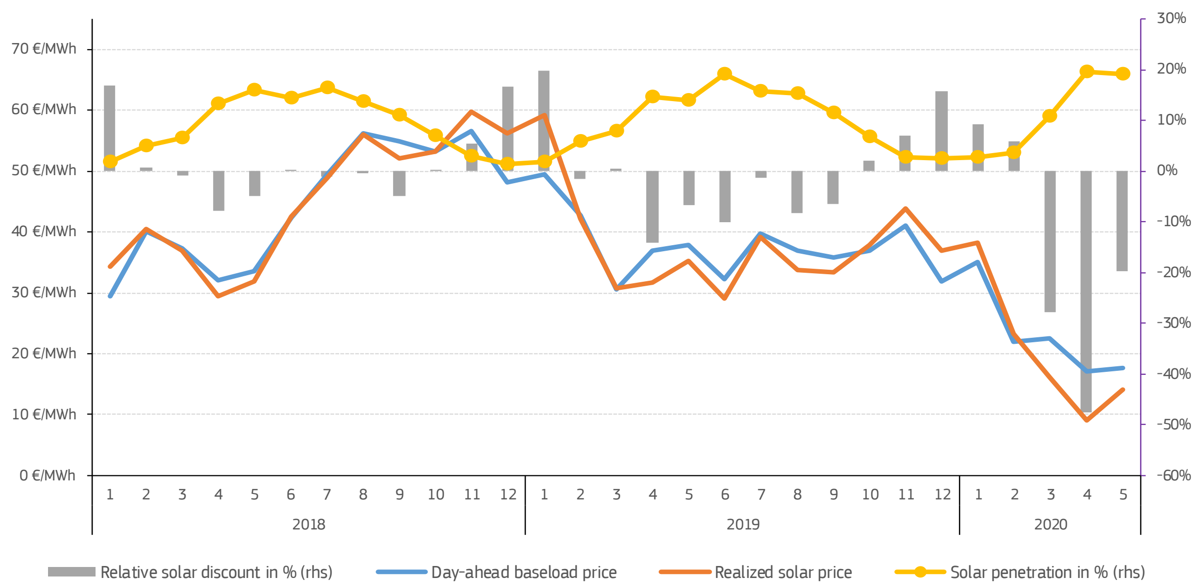
Figure 15 – Occurrence of negative hourly prices in the German day-ahead market



Source: Platts

- **Figure 16** shows that the increased presence of solar energy in the German mix affected the remuneration this renewable source receives from the day-market. Realised prices of PV-based electricity declined dramatically in compared to the baseload prices this spring. The difference was most pronounced in sunny April when high solar generation during the day coincided with low demand affected by restrictive measures and drove hourly prices in periods crucial for PV generators to very low levels (as can be seen in **Figure 14**). Similar, if not so extreme, declines in market value were observed in the wind sector. As the vast majority of renewable generation in the country is subsidized, the lower remuneration derived from the market means that more resources are needed to be collected from electricity consumers via a green levy in order to maintain a guaranteed level of revenue (a feed-in tariff for instance) for the owners of renewable sources. However, falling electricity consumption negatively impacted revenues collected via the levy as well. The combined force of the above-mentioned factors resulted in a negative balance of €1.9bn between January and May 2020 on the account from which renewable sources are financed. As the balance is expected to continue deteriorating, a need to substantially increase the levy 2021 arose in order to cover the growing financing gap. A report by the Institute of Energy Economics at the University of Cologne estimated this increase at 25% (from 67.56 €/MWh in 2020 to 84.40 €/MWh in 2021), which would measurably impact retail electricity prices and drive them 6% higher compared to 2019 levels, even if lower wholesale electricity prices were passed on to end consumers.
- On 3 June 2020, the German government decided to cap the green levy at 65 €/MWh in 2021 and 60 €/MWh in 2022 and to compensate the resulting deficit on the account through public finances. The additional costs for the national budget are estimated at around €8bn in 2021 and €2bn in 2022.

Figure 16 – Market value of solar-based electricity in Germany compared to day-ahead baseload prices

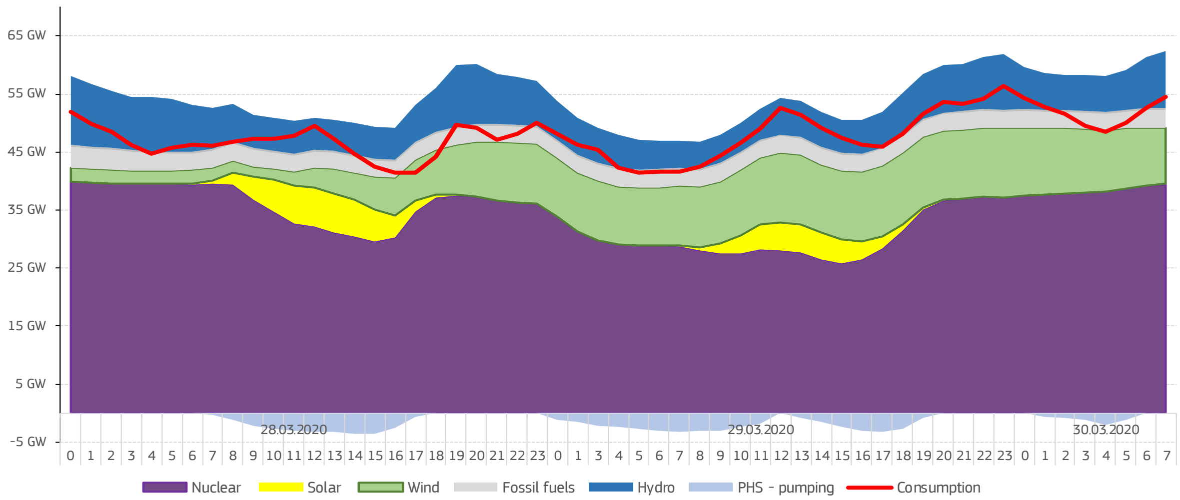


Source: ENTSO-E. Realised solar price is a generation-weighted price whereby weights are determined by the total solar generation in Germany in each individual hour of a given month.

- **Figure 15** shows how the French electrical system coped with a period low demand and increased renewable penetration. With fossil fuels marginalized essentially to cogeneration plants supplying heat, the nuclear fleet took over the task of providing the main source of flexibility. This could be observed during the last weekend of March 2020. On Saturday, simultaneously growing solar and wind generation forced a 10 GW reduction in nuclear output within a few hours and then a return of around 6 GW in the evening to compensate for ebbing solar activity. Next day, nuclear generation had to be limited even more in the afternoon due to rising wind speeds and falling consumption. This was accompanied by three hours of negative prices, a relatively rare occurrence in the French day-ahead market. As the evening progressed, nuclear generation ramped up by 11 GW within 5 hours. Pumping in hydro storage plants helped mop up excess generation, but the main burden of flexibility provision fell on the nuclear fleet. In its report on the episode, the French TSO points out that while such situations have not been frequent and that the rise in renewable generation has so far largely displaced coal and gas plants, this might change in case the low-demand conditions were to last longer and renewable penetration continued to grow. It also suggests that further sources of flexibility such as ECV charging or green hydrogen production could help with system management and make better use of the abundance of clean and cheap electricity. In this respect, the lockdown period with its sudden rise in renewable penetration could be seen as a precursor of things to come and an opportune moment to pause, learn from the experience and plan for the future accordingly.

- Low electricity consumption and higher wind or solar generation imposed greater demands on the flexibility of nuclear power plants in other countries as well. Reactors were either taken offline or powered down in Sweden and the UK for instance.

Figure 17 – French generation mix during the last weekend of March



Source: ENTSO-E

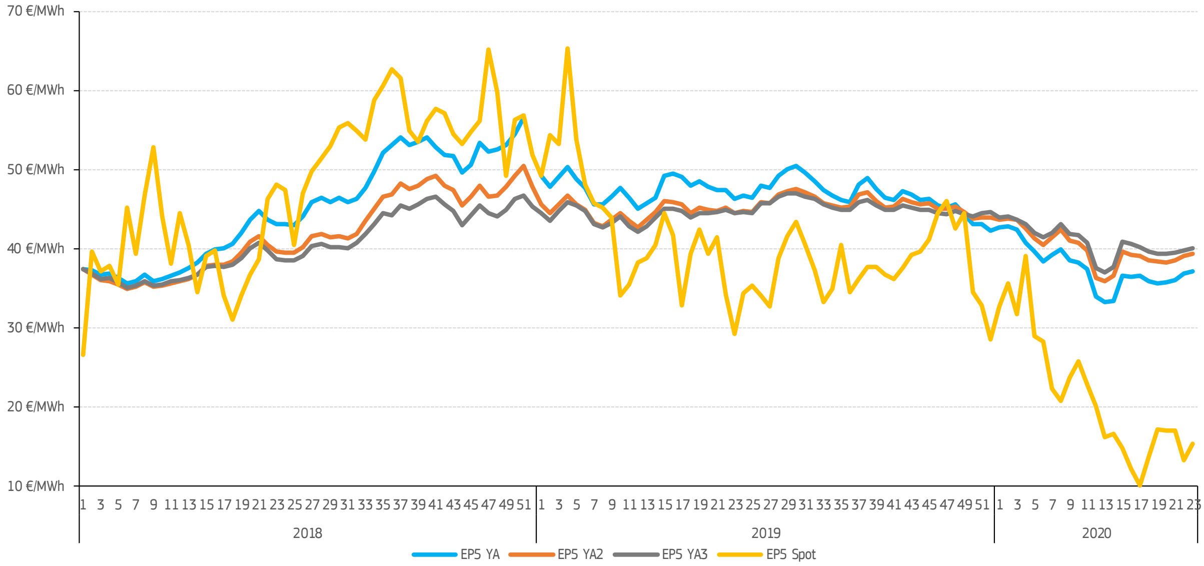
- In order to obtain a comprehensive picture of how European wholesale electricity prices have developed, a consumption-weighted baseload benchmark (EP5) of 5 most advanced markets offering a 3-year visibility into the future was created and compared to a day-ahead (spot) equivalent. As shown in **Figure 18**, since the beginning of 2019, markets have been expecting power prices in the future to be higher than in the spot market, a situation which favours buying electricity closer to the time of delivery. The gap between the spot and year-ahead benchmarks has grown to almost 20 €/MWh during the pandemic due to low demand, high presence of renewables in the mix and abundance of cheap gas. Spot benchmark reached its all-time low in April.

- An interesting shift happened on the forward curve. While in the past two years, the market expected prices to generally decline going into the future (the so called backwardation) on the back of higher renewable penetration, the opposite has been true lately. The further one ventures along the recovery road, the higher the prices should climb, with the biggest jump apparent between year-ahead (2021) and year-ahead+2 (2022) quotes. At the end of May 2020, baseload power for future delivery sat some 5-7 €/MWh (roughly 10-15%) lower than in 2019. Remarkably, the inflection point at which backwardation on the curve shifted into contango came at the beginning of December 2019, months before the crisis started to inflict lasting damage on the economy.

- Forward prices went through a slump at the beginning of the lockdown period, when the number of known unknowns surrounding the coronavirus grew exponentially, but largely recovered their losses by the end of May. This underscores the fact that noticeable declines in future power prices happened before the most severe phase of the pandemic. In some respects, expected power prices are not that different from levels seen a few years ago. Benchmarked baseload electricity for delivery in 2021 was sold at around 36 €/MWh at the beginning of 2018; about the same price was offered for the same delivery year (as the year-ahead contract) in May 2020.

- **Figure 18** illustrates that the interplay between spot and forward prices is not always straightforward. It also sheds some light on retail price formation. Since a significant part of electricity for final consumption is bought on the forward market by traders year-ahead of the delivery or even longer, forward wholesale prices play a vital role in determining the energy component of retail prices for households and the industry. That is why a decrease in wholesale prices is always channelled into retail prices with some delay. Given the fact that forward prices went down much less than their spot peers since the beginning of 2019, a question mark hangs over the extent of the decrease in the energy component of retail prices that can be expected in 2021. According to data from Vaasaett, the average energy component of household retail prices in EU27 capitals started to decline measurably in April and this trend continued in May. The decline could be partly explained by falling spot prices in the wake of the pandemic, but the development of forward wholesale prices, which have been sliding since the second half of 2019, could also be partly responsible.

Figure 18 – Weekly spot and forward baseload prices – weighted average of 5 European markets



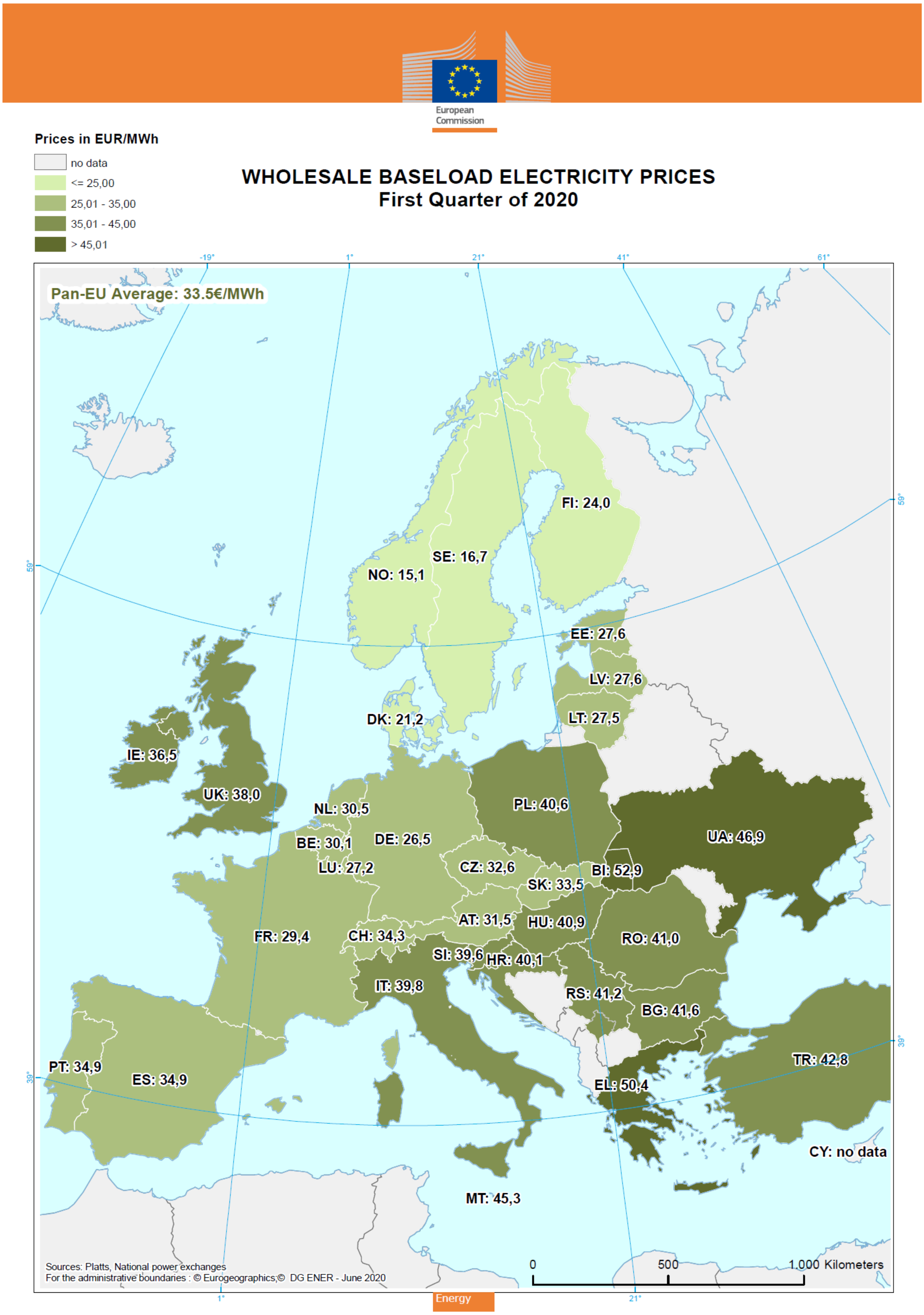
Source: Platts. Markets included in the benchmark are France, Germany, the Netherlands, Spain and Nord Pool. Prices are weighted according to the consumption levels in individual markets. Forward prices were obtained from several European power exchanges: EEX (France, Germany), Endex (the Netherlands), OMIP (Spain) and Nord Pool. 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.

3 European wholesale markets

3.1 European wholesale electricity markets and their international comparison

- The map on the next page shows average day-ahead wholesale electricity prices across Europe in Q1 2020. The cheapest baseload power prices were observed in the Nordic region, which benefitted from ample hydro stocks, surging wind generation and above-average winter temperatures. Markets in the eastern and southern parts of the continent (Poland, Hungary, Romania, Bulgaria and Greece), with a relatively high share of carbon-intensive generation or with greater reliance on imports, found themselves on the other side of the price spectrum.
- The highest average prices in Q1 2020 in the EU27 were registered in Greece (50 €/MWh) and Malta (45 €/MWh), followed by Bulgaria (42 €/MWh), Romania (41 €/MWh), Hungary and Poland (both 41 €/MWh). Some of these countries traditionally rely on imports of electricity (Greece, Hungary), some have limited cross-border transmission capacities (Malta, Greece), and some faced falling domestic output from lignite sources burdened by elevated carbon costs (Poland, Greece, Bulgaria, Romania). The lowest quarterly wholesale prices were recorded in Norway (15 €/MWh) and Sweden (17 €/MWh), where high hydro reservoir levels and rising wind generation kept baseload contracts in check.
- The pan-EU average of day-ahead baseload prices reached 34 €/MWh in the reference quarter, down 33% in a year-on-year comparison. Compared to Q4 2019, the quarterly average fell by 24% on the back of weak demand and increased wind generation.
- In an annual comparison, all markets saw prices coming down from relatively high levels in Q1 2019. The biggest decreases happened in Norway (-68%), Sweden (-64%), Denmark and Finland (both -50%).

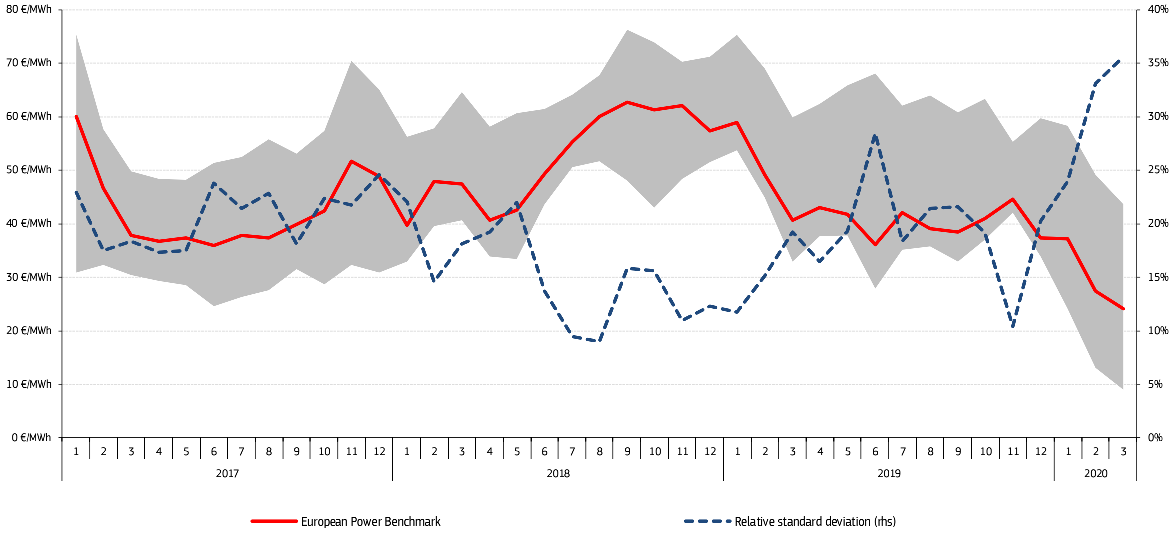
Figure 19 – Comparison of average wholesale baseload electricity prices, first quarter of 2020



Source: European wholesale power exchanges, government agencies and intermediaries

- **Figure 20** shows the European Power Benchmark index 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 even though wholesale prices were falling across different regional markets in Q1 2020, divergence levels increased considerably. This was due to the fact that the fall in prices in countries and regions that traditionally form the lower part of the spectrum (Nord Pool, Germany, France) was greater than in Greece, the UK or Italy where wholesale prices are typically higher. For instance, the average Nord Pool system price went down by 60% in Q1 2020 compared to Q4 2019. As a result, the relative standard deviation figure in wholesale markets under observation reached its highest level since 2015 in the reference quarter.

Figure 20 – The evolution of the lowest and the highest regional wholesale electricity prices in the European day-ahead markets and the relative standard deviation of the regional prices



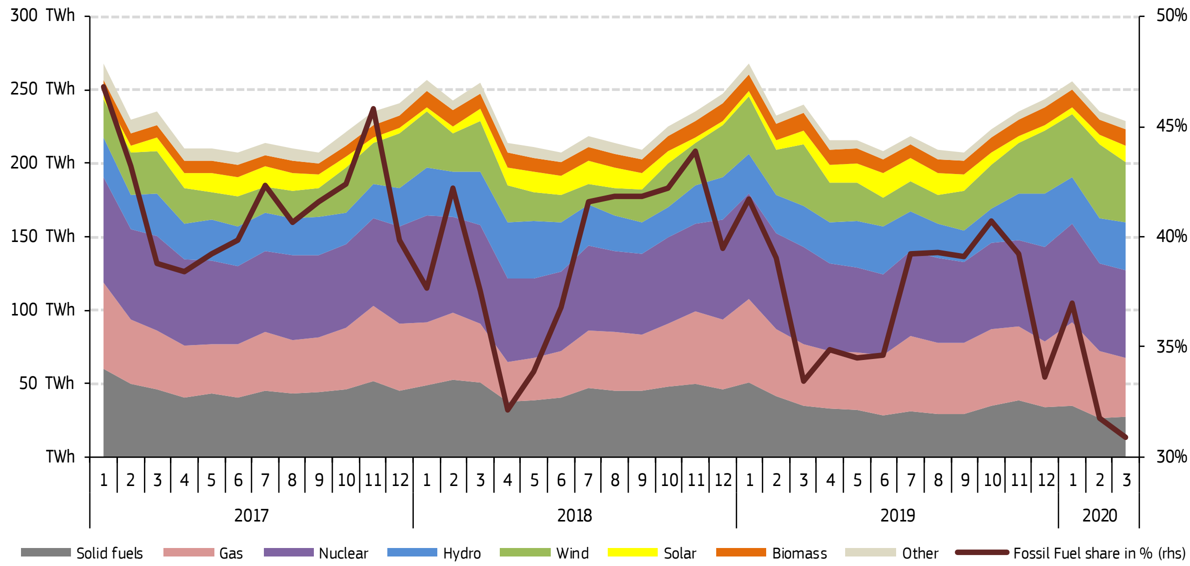
Source: Platts, European power exchanges. The shaded area delineates the spectrum of prices across European regions.

- **Figure 21** shows the evolution of the electricity mix in the EU27. The structure of generation in the reference quarter was influenced mainly by high renewable output and falling demand 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 38% in Q1 2019 to 33% in Q1 2020. This was the lowest quarterly figure on record. On the other hand, the share of renewables (hydro, biomass, wind and solar) jumped from 34% to 40% during the same time, as nearly all renewable sources including hydro posted strong gains year-on-year. The share of nuclear generation declined from 27% to 26% year-on-year due to lower generation of the French fleet and power plant closures in Germany and Sweden.

- Within the fossil fuels complex, both coal and gas suffered losses compared to Q1 2019, signifying the limited short term potential for further coal-to-gas switching on the continent. Less CO2-intensive gas generation saw its share of the mix unchanged at 20% in the reference quarter, but lost 3 TWh in absolute terms year-on-year. Only Portugal experienced a significant rise in gas output (+1.5 TWh) at the expense of coal (-2.1 TWh). Solid fuels went through a sharp drop both in relative and absolute terms. Their share in the mix was reduced to 12% in the reference quarter (from 17% in Q1 2019), which translated into 38 TWh less electricity produced by burning coal and lignite in a year-on-year comparison. Renewables, on the other hand, generated 38 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 21**), 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. In Q1 2020, CO2 prices were on average similar to those in Q1 2019. Nevertheless, 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 Q1 2020 fell by 25% year-on-year (or 15 TWh), while coal-fired generation plunged by 35% year-on-year (or 23 TWh). Thus, the combined share of coal and lignite (12%) in the EU27 power mix in Q1 2020 fell below that of hydro (13%).

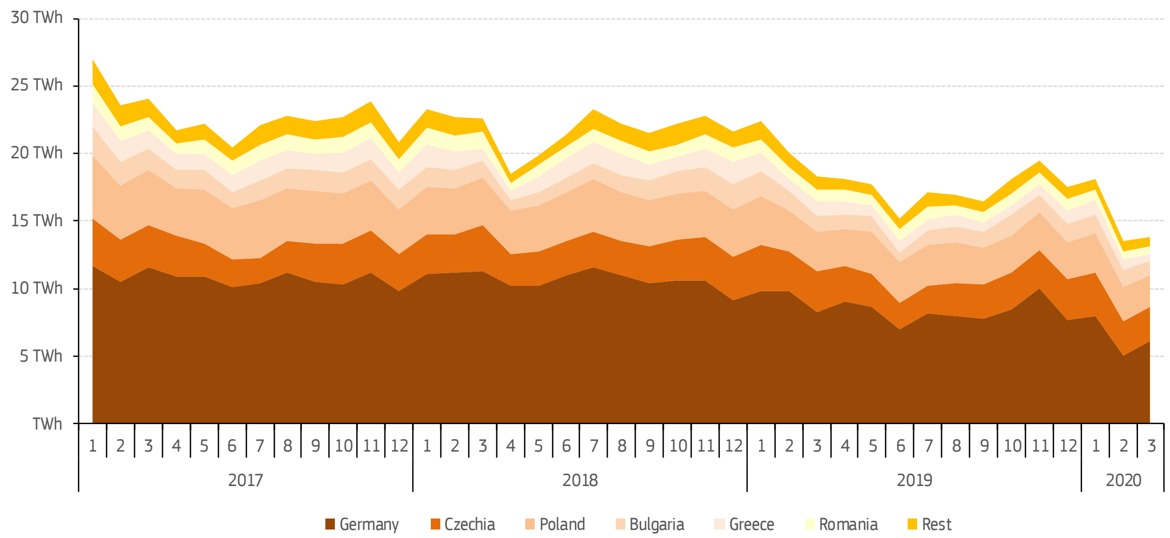
Figure 21 – Monthly electricity generation mix in the EU27



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 22.** The total monthly output dropped below 15 TWh for the first time in February and March 2020. Germany, home to the largest fleet of lignite units, experienced the steepest year-on-year decline in generation (-32%) in Q1 2020 due to surging renewables and falling demand. In contrast, lignite-fired output in Czechia, the second largest producer, decreased only by 11% in the same period. In Poland, lignite-fired units reduced their generation by 17% year-on-year. The three countries accounted for 77% of the total lignite-based generation in the EU27 in Q1 2020. Germany aims to phase out lignite from its power mix by 2038. The latest developments indicate the possibility of an earlier, market-driven end.

Figure 22 – Monthly generation of lignite power plants in the EU27

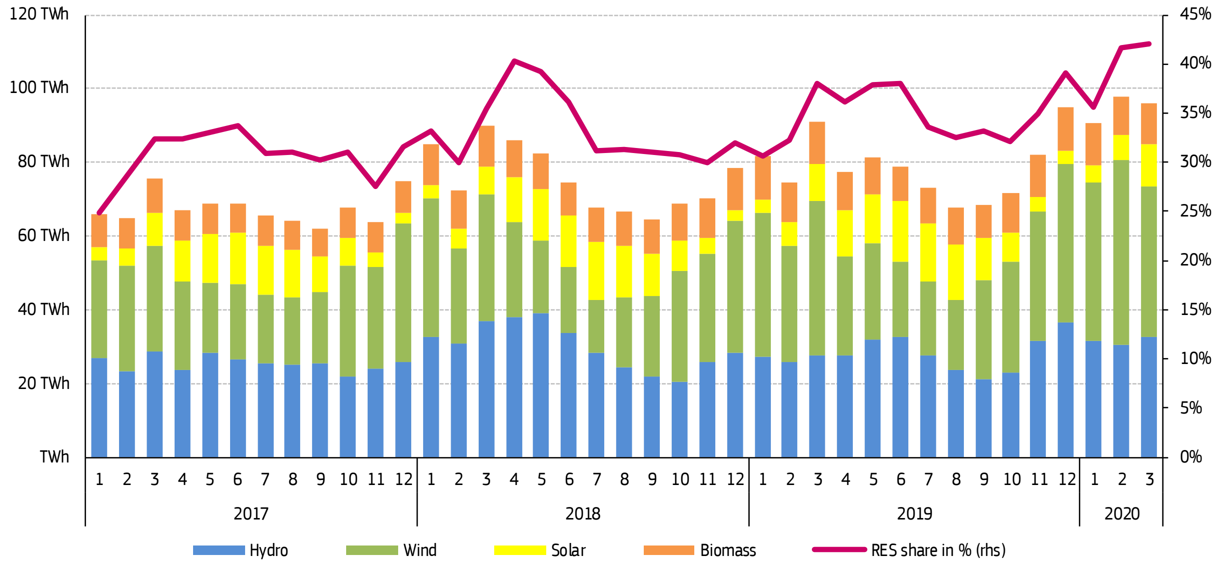


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 23** depicts the evolution of the monthly renewable generation in the EU27, alongside its share in the electricity generation mix. Renewable energy sources reached a milestone in Q1 2020 as their quarterly share in the mix rose to 40% for the first time. This was more than six percentage points higher compared to Q1 2019. Falling electricity consumption and a 14% year-on-year rise in renewable generation contributed to the unprecedented surge in renewable penetration. During the weekend of 21-22 March, when covid-related restrictions were already wide-spread and power demand significantly affected, renewable energy breached the 50% barrier in EU's electricity mix.

- The main drivers behind the increased presence of renewable power in the reference quarter were very good volumes of hydro sources (up 17 TWh thanks mainly to increases in France, Italy and on the Iberian Peninsula) and record high wind output, which in its onshore segment expanded by 17% year-on-year (or 17 TWh) and in the off-shore sector surged by 43% year-on-year (or 4 TWh). Solar-based generation in Q1 2020 grew by 15% (or 3 TWh) compared to Q1 2019, while biomass-based generation stagnated.
- Wind-powered sources performed impressively in the first three months of 2020 and with a 19% share in the mix became again the largest contributors to the overall renewable output. The shares of solar and biomass remained largely unchanged in Q1 2020, compared to the same quarter of the previous year. The largest increases in wind output came from Germany (+9 TWh), France (+4 TWh), Sweden (+3 TWh) and Belgium (+2 TWh). Offshore wind farms in Belgium nearly doubled their generation volumes in the reference quarter.
- At 40%, the combined share of hydro, biomass, wind and solar sources in the EU27 electricity generation in Q1 2020 was higher than in other major economies. The share of renewables in the US power mix in the reference quarter stood at 21%, whereas in China and India renewable energy constituted 22% and 20% of their respective total power generation during the same quarter.[2]

Figure 23 – Monthly renewable generation in the EU27 and the share of renewables in the power mix

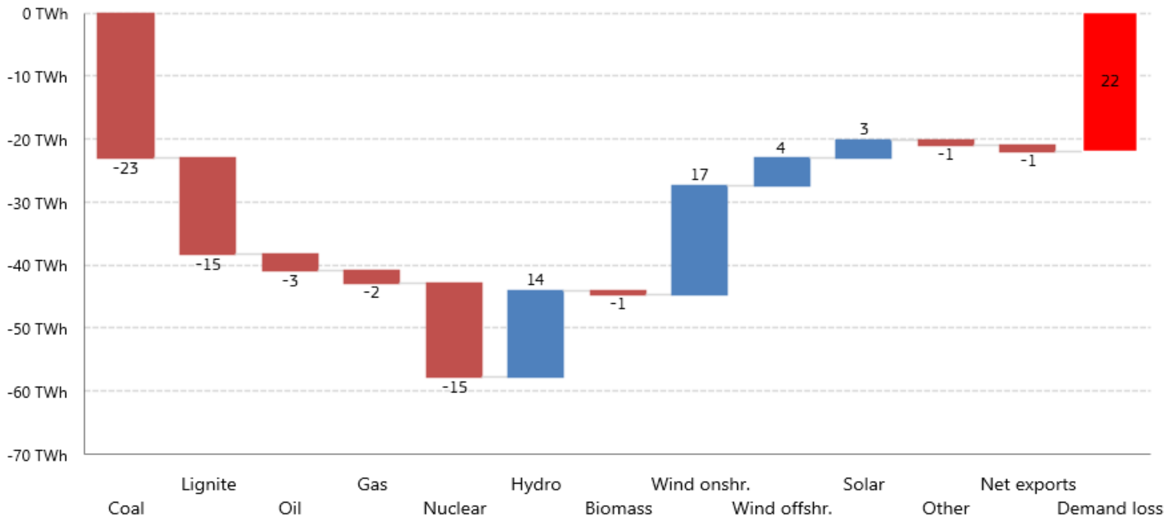


Source: ENTSO-E, Eurostat, DG ENER. Data represent net generation.

- **Figure 24** visualises changes in the EU27 electricity generation balance in the reference quarter compared to the same quarter a year before. Conventional power plants' running hours were reduced due to rising renewable generation and falling demand. As a result, the fossil fuels sector suffered a combined loss of 43 TWh, while nuclear generation declined by 15 TWh (mainly on account of the supressed French fleet). Renewable sources produced 38 TWh of electricity more than in Q1 2019. Net exchanges with third countries remained largely unchanged. The EU27 balance finished with a 4 TWh net surplus in Q1 2020, making the bloc a net exporter of electricity.

[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.

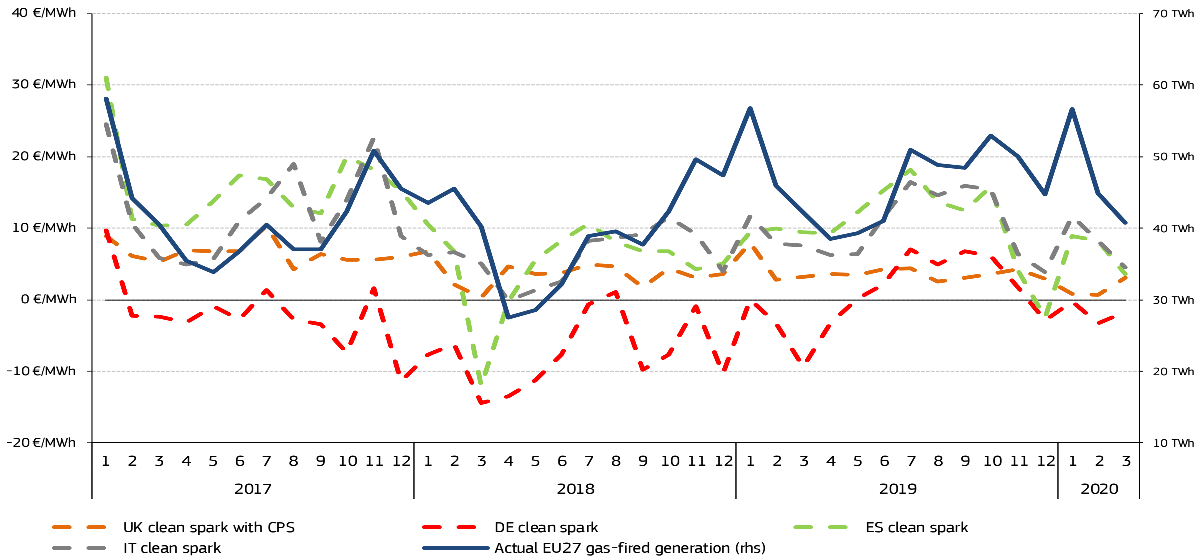
Figure 24 – Changes in power generation in the EU27 between Q1 2019 and Q1 2020



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 Q1 2020, but its margins gradually deteriorated despite falling spot gas prices, as the impact of lower power prices proved to be stronger.
- As shown in **Figure 25,** the profitability of gas generation recovered somewhat in Italy and Spain at the beginning of 2020 but fell in February and March as power prices in these markets declined. Clean spark spreads were relatively stable, but mostly negative in Germany in Q1 2020 due to very low spot power prices. The operators of British gas-power plants faced strong headwinds in February when high wind generation pushed margins close to zero. Gas-fired generation volumes largely corresponded to the movement of spreads in respective markets. The total EU27 gas generation reached 142 TWh in the reference quarter, compared to 145 TWh in Q1 2019.

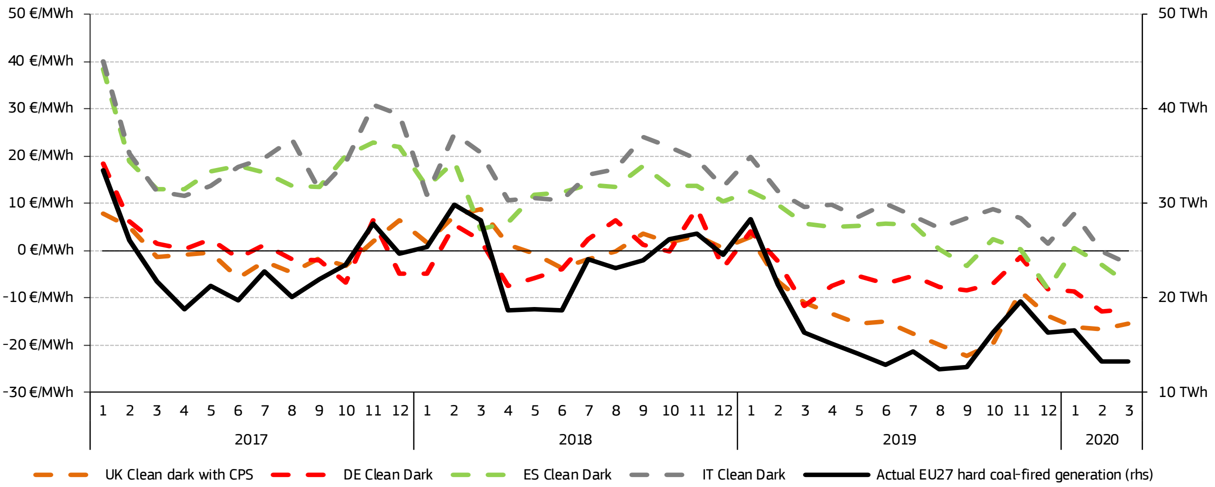
Figure 25 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU27



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 26** illustrates that coal generators across Europe continued to operate in a mostly adverse environment in Q1 2020. Since February, all the markets under observation showed zero or negative clean dark spreads due to rapidly falling power prices. In March, profitability fell into negative territory even for Italian coal power plants, an unusual development underlining the gravity of the disruption caused by the pandemic. At 43 TWh, the total coal generation in the EU27 in the reference quarter was a third lower than in Q1 2019, but still surprisingly high under the circumstances.

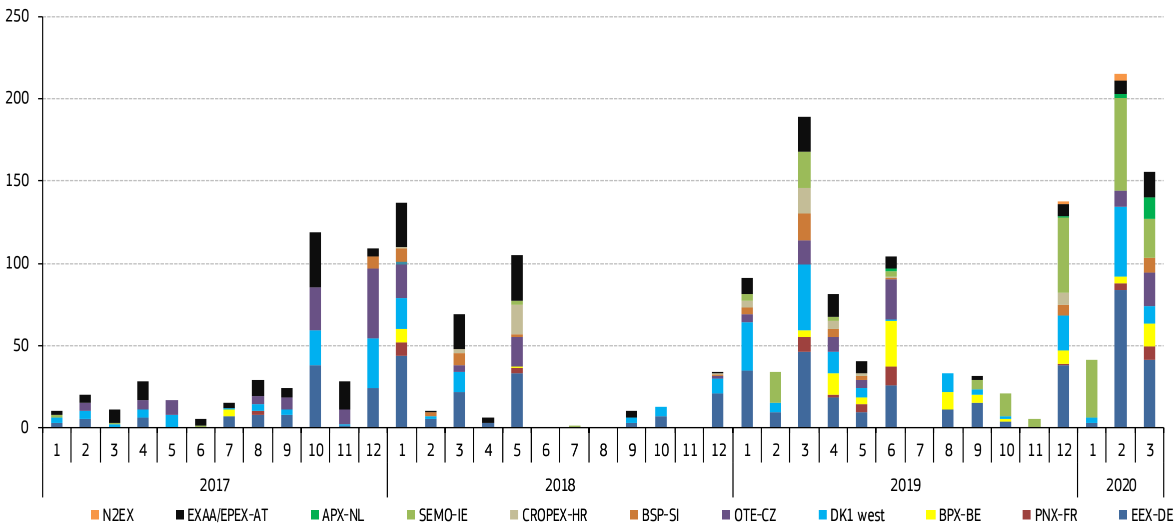
Figure 26 – Evolution of clean dark spreads in the UK, Spain, Italy and Germany, and electricity generation from hard coal in the EU27



Source: ENTSO-E, Eurostat, Bloomberg

- **Figure 27** 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 421, the number of hours with negative wholesale prices in Q1 2020 was a third higher in the observed bidding zones than in the previous Q1. The highest number of falls into negative territory was concentrated in February due to extreme wind speeds in Western Europe. Germany recorded the highest number of negative hourly prices (128) in Q1 2020 and was closely trailed by the integrated Irish zone (116). On the Irish island, negative prices occurred exclusively during the night and in the morning. In Germany, the daily distribution was more evenly spread as strengthening solar irradiation caused hourly prices to go negative each Sunday in the second half of March, when the effect of covid-related restrictions started to significantly affect demand. 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, Sweden and Finland (both for first time ever) or the UK.

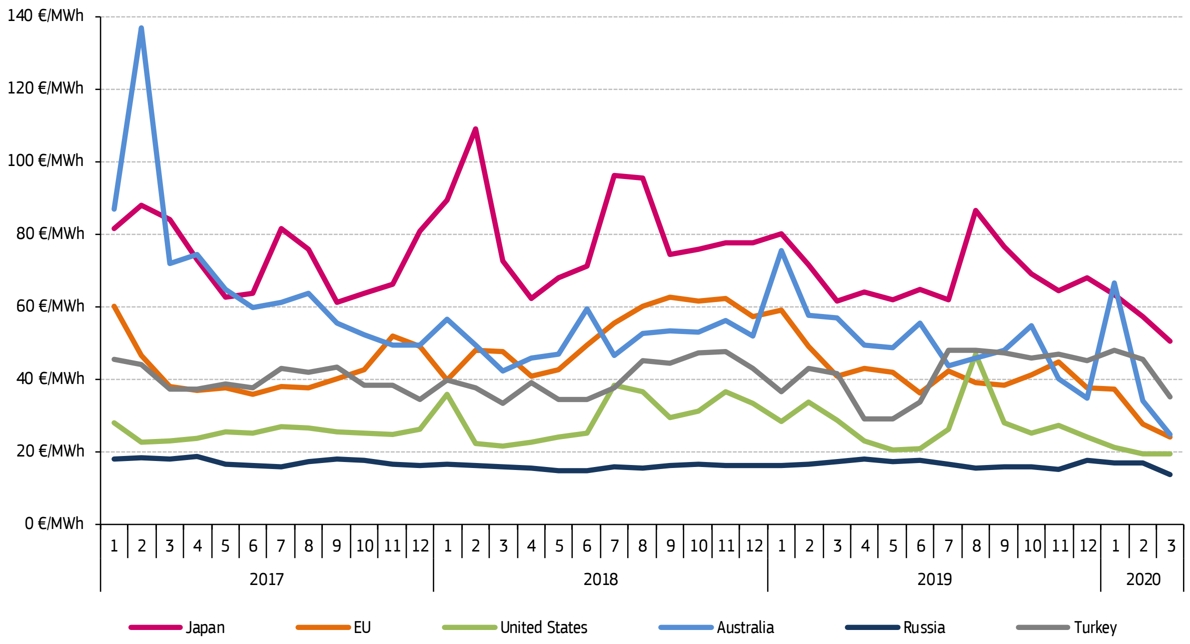
Figure 27 – Number of negative hourly wholesale prices on selected day-ahead trading platforms



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

- **Figure 28** compares price developments in the wholesale electricity markets of selected major economies. Prices were on a decreasing trajectory across the board in Q1 2020. Japan remained the most expensive of the markets under observation, with day-ahead prices reaching 57 €/MWh on average during the reference quarter. Meanwhile, at the other end of the spectrum, average wholesale prices in the United States decreased to around 20 €/MWh on the back of mild winter weather which supressed power demand. Wholesale prices fell slightly also in Russia which had the cheapest electricity (16 €/MWh) of the selected group.
- Australia experienced a brief price spike in January amid high summer temperatures in the Southern Hemisphere, tight supply and damaged transmission lines, but saw prices falling to European levels afterwards. Wholesale prices in Turkey averaged 43 €/MWh in Q1 2020 (down 7% compared to Q4 2019). The European Power Benchmark of nine major markets went through the steepest relative decline, falling by 28% quarter-to-quarter to 30 €/MWh in Q1 2020.

Figure 28 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

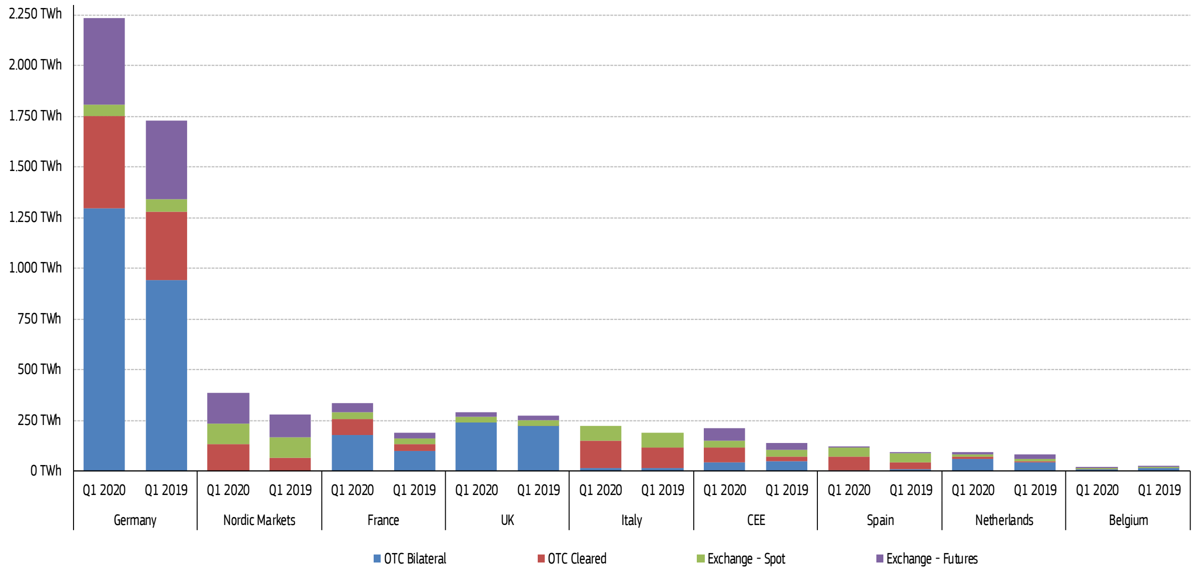


Source: European Power Benchmark, JPEX (Japan), AEMO (Australia), JCS ATS (Russia), Energy Exchange Istanbul (Turkey) and the average of PJM West, ERCOT, MISO Illinois and CAISO regional wholesale markets in the United States.

3.2 Traded volumes and cross-border flows

- **Figure 29** shows that elevated levels of volatility brought more trading activity to most European wholesale markets across the entire product spectrum in Q1 2020. The highest year-on-year uptick in volumes was recorded in France (+78%), driven mainly by the over-the-counter (OTC) segment. This development could be tied to the ARENH mechanism which allows alternative suppliers to purchase electricity from the dominant player in the market at a fixed price of 42 €/MWh. As day-ahead prices in the French wholesale market dived below the fixed level and consumption plunged in March, many suppliers were left with excess deliveries that had to be disposed of somehow. This probably impacted trading volumes, which jumped to very high levels particularly in March. Central Eastern Europe (+55%), Nordic markets (+39%), Spain (+32%) and Germany (+29%) also registered significant increases in traded volumes in the reference quarter. Belgium (-17%) was the only market suffering from falling volumes in Q1 2020. The total traded volume in all markets under observation in Q1 2020 rose by 31% year-on-year to 3,905 TWh, the highest quarterly figure on record.
- In Germany, the largest and most liquid market by far, activity increased less at exchanges (+8%) than in the OTC segment (+37%) in the reference quarter. Similar trends were visible in most other markets with the exception of the CEE region where volumes rose significantly also at local exchanges (+54%). Overall, exchange-based trading volumes increased by 128 TWh year-on-year in Q1 2020, but saw their share in the total electricity market reduced to 29% from 33% in the previous year. This was due to the fact that the volume in the OTC segment expanded by 40% year-on-year (or 700 TWh) in Q1 2020. The rise was driven mainly by deals closed in Germany (+471 TWh) and France (+125 TWh).

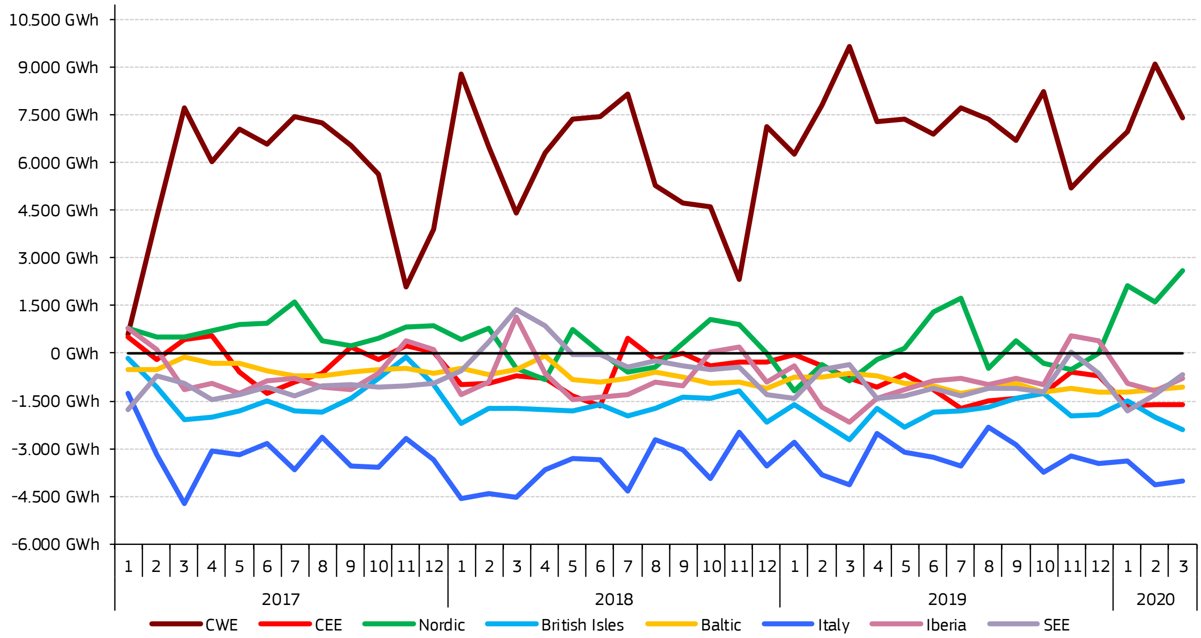
Figure 29 – Changes in traded volumes in the most liquid European electricity markets



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

- **Figure 30** reports on the regional cross-border flows of electricity. Central Western Europe emerged again as the main exporting region, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. Monthly net export flows fluctuated between 7 and 9 TWh, adding up to 23.5 TWh for the whole reference quarter (unchanged compared to Q1 2019). High wind and hydro generation contributed significantly to this result.
- As in previous quarters, Italy remained the largest importer of electricity in Q1 2020, receiving 11.5 TWh of net inflows, mainly from Switzerland and France and, to a lesser extent, Slovenia. The net Italian position slightly worsened compared to the previous Q1 on the back of a significant drop in coal- and oil-fired generation and low wind availability which could not compensate fully for falling consumption. Net exports to Greece reached 1 TWh on a net basis in the reference quarter. The British Isles, the second largest importing region, decreased its net purchases in Q1 2020 by 10% year-on-year to 5.9 TWh on the back of surging domestic wind generation. The CEE region's net position (-5 TWh) deteriorated significantly in Q1 2020 compared to Q1 2019 on the back of falling lignite generation in Poland, Czechia and Romania. A similar story played out in South Eastern Europe where Bulgarian and Greek lignite capacities felt the pressure of elevated carbon costs.
- The Nordic region capitalized on ample hydro reservoirs in Norway and rapidly expanding wind capacity in Sweden to reach 6.3 TWh of net exports, its highest surplus on record. This was in sharp contrast with last year when dry weather forced the region to import 2.4 TWh on a net basis. The Iberian Peninsula reduced net imports from France and Morocco by 1.4 TWh year-on-year in Q1 2020 thanks to high hydro generation both in Spain and Portugal.

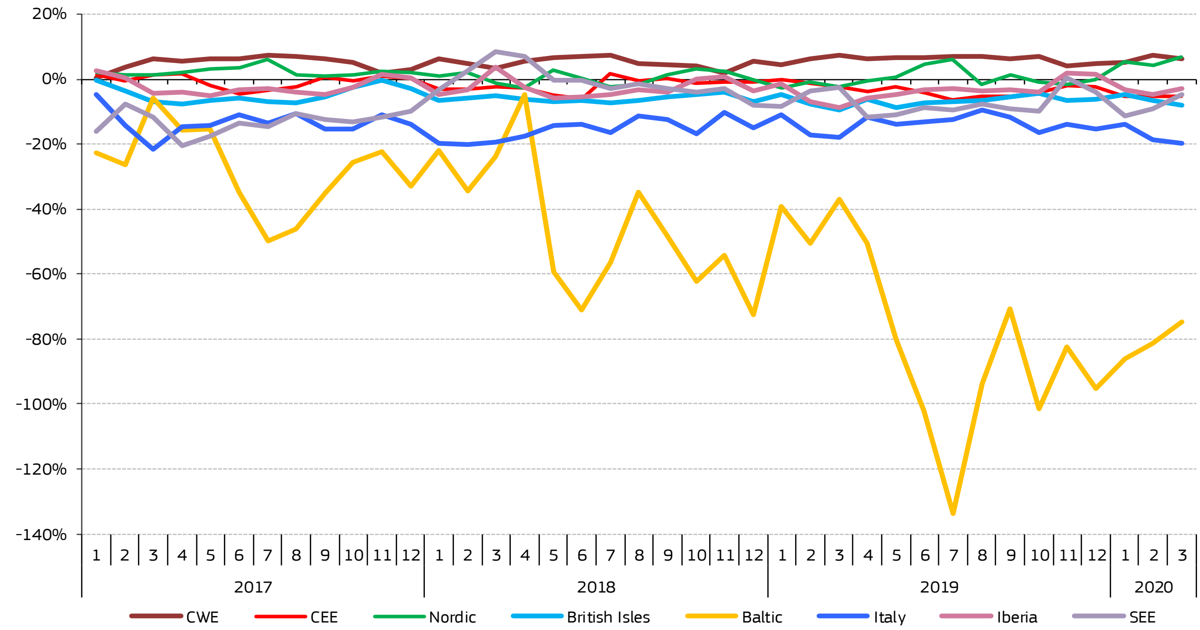
Figure 30 – European cross border monthly physical flows by region



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 31** 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 further improved in Q1 2020 compared to the previous quarter, as its net imports of electricity compared to domestic generation declined to 81%. High hydro generation in Latvia and falling consumption across the three countries of the region were the main contributors.
- Italy remained the second biggest importer relative to its production (17%). For the rest of the regions, net imports (or exports) did not exceed 10% of domestic generation. It is noteworthy that outflows from the CWE region, which is a significant exporter in absolute terms, are not large in relation to its total production. In Q1 2020, net CWE exports corresponded to 6% of the total regional generation.

Figure 31 – The ratio of the net electricity exporter position and the domestic generation in European regions



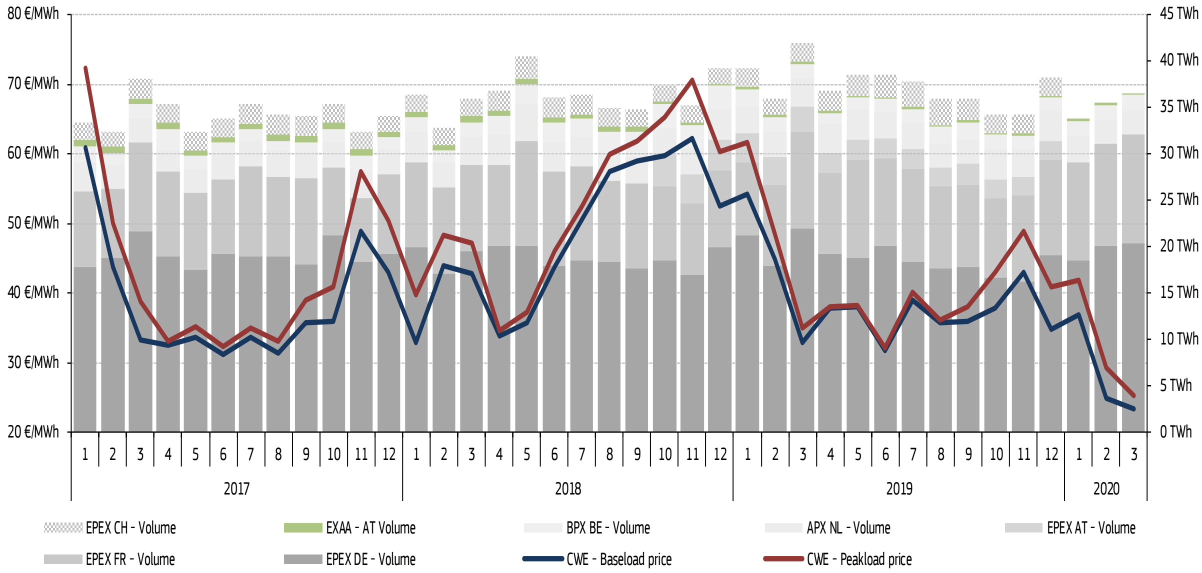
Country distribution in regions is the same as in the previous figure. The -100% level means the same amount of electricity is imported as produced domestically. Source: ENTSO-E, TSOs, Eurostat, DG ENER calculation

4 Regional wholesale markets

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

- Average baseload electricity prices in the Central Western Europe (CWE) region were on a downward trajectory throughout the reference quarter on the back of mild winter weather and high wind availability in January and February and the covid-related demand shock in the second half of March. As consumption slumped in the wake of widespread lockdowns, the regional monthly baseload average slid to 23 €/MWh in March, its lowest level on records dating back to 2012. Compared to Q4 2019, the average baseload price in the region declined by 36% to 28 €/MWh in the reference quarter. Average peakload prices narrowed their spread against their baseload peers, in line with regular seasonal trends caused by an increased presence of solar generation energy in the mix.
- Reduced generation of the French nuclear fleet, decreased competitiveness of coal and lignite capacities, high water reservoir in the Alps and good wind availability impacted generation volumes and cross-border flow patterns in the region. Thus, Switzerland produced 1 TWh more in Q1 2020 compared to the previous Q1 thanks to higher hydro output and Belgium (+2 TWh year-on-year) benefited from surging wind capacities and good weather conditions. Meanwhile, the Dutch production volumes went down (-2 TWh year-on-year) mainly due to reduced running hours of its coal fleet. The total French output fell as well (-3 TWh year-on-year) as higher hydro and wind generation could not fully compensate for a sharp fall in nuclear production. Germany suffered the biggest drop in generation volumes (-9 TWh year-on-year) in the reference quarter due a significant fall in coal and lignite output.
- Austria shut down its last coal power plant in Mellach at the end of the heating season, becoming the second EU Member State to abandon coal for residential heating and power generation after Belgium. Meanwhile, Germany has finalized its plan to phase out coal and lignite from its power mix by 2038 at the latest. A shutdown schedule for individual lignite power plants was drawn up. For hard coal, auctions for plant operators are foreseen to take capacity off the grid according to the government's timetable. According to the plan, 8 GW of hard coal and 9 GW of lignite capacities are to remain online by 2030 (from 23 GW of hard coal and 18 GW of lignite at the end of 2019). Several reviews are scheduled to decide whether the phase-out can already be completed by 2035. France aims to cease coal-fired electricity generation in 2022.

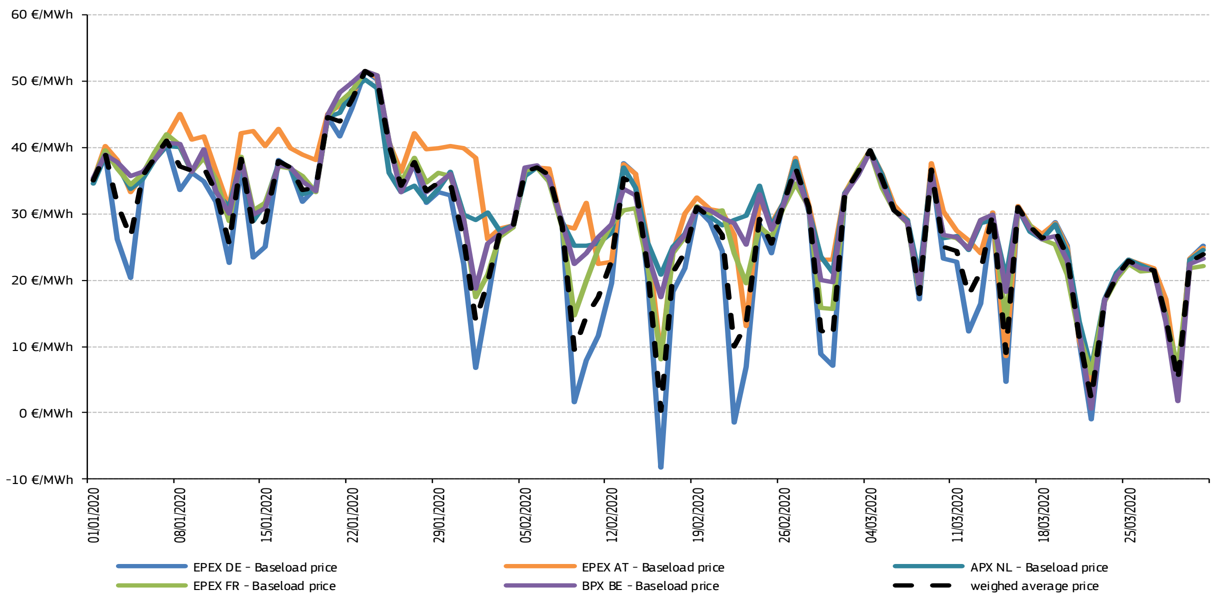
Figure 32 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe



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

- **Figure 33** shows the daily average regional day-ahead prices in the reference quarter. February saw consecutive weekends of negative power prices in the German market due to high winds speeds (storms Sabine and Victoria). The trough came on 16 February (Sunday) when the daily average sank to 8 €/MWh below zero, prices went negative for 23 hours of the day and renewable sources took over more than three quarters of the power mix. At the other side of the price spectrum, a local maximum above 50 €/MWh was reached during a cold snap in the second half of January when low temperatures combined with calm weather. Daily average prices have displayed a remarkable level of convergence since the beginning of lockdowns in the second half of March.

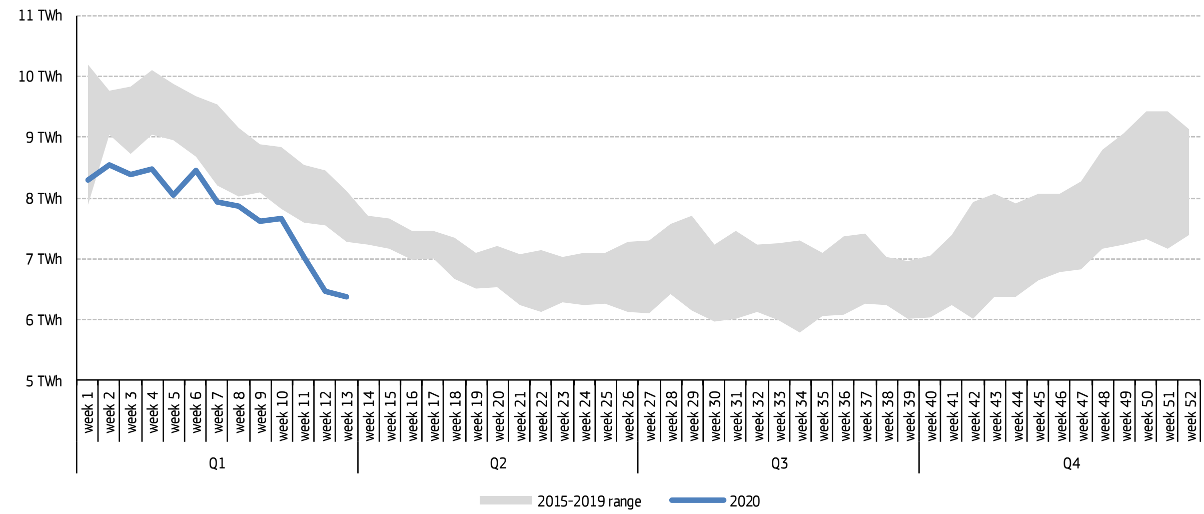
Figure 33 – Daily average power prices on the day-ahead market in the CWE region



Source: Platts.

- As shown in **Figure 34,** the French nuclear fleet displayed a weak performance in Q1 2020 due to a flurry of outages, maintenance overruns and falling demand. The total generation in the reference quarter fell by 9% year-on-year (or 10 TWh). Over the whole winter, nuclear output averaged 44 GW, about 6 GW lower than last winter. In April, the annual production target was revised significantly down to 300 TWh 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 34 – The weekly amount of generated nuclear electricity in France



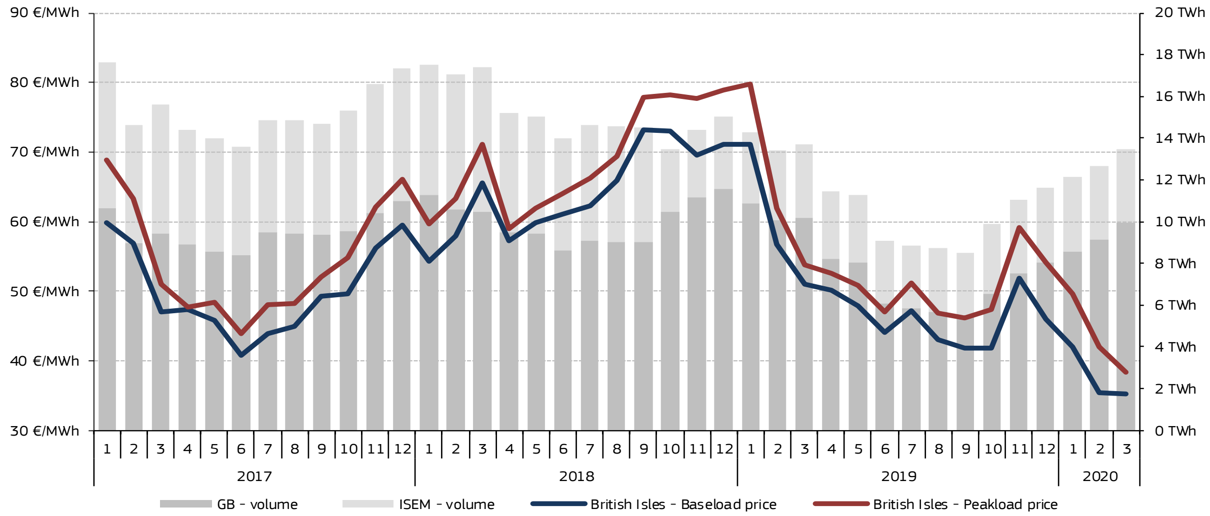
Source: ENTSO-E

4.2 British Isles (GB, Ireland)

- **Figure 35** 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 were continuing in their slide during Q1 2020 on the back of mild temperatures, high wind generation, falling gas prices and weak demand. In March, when restrictions on economic activity started to seriously affect power consumption, the monthly average settled at 35 €/MWh, the lowest level on records going back to 2014. Compared to Q4 2019, the average baseload price on the British Isles declined by 19% to 38 €/MWh in the reference quarter.

- Trading activity on the British day-ahead market was growing gradually in each month of the reference quarter. Compared to Q1 2019, however, the traded volumes were still 11% lower.

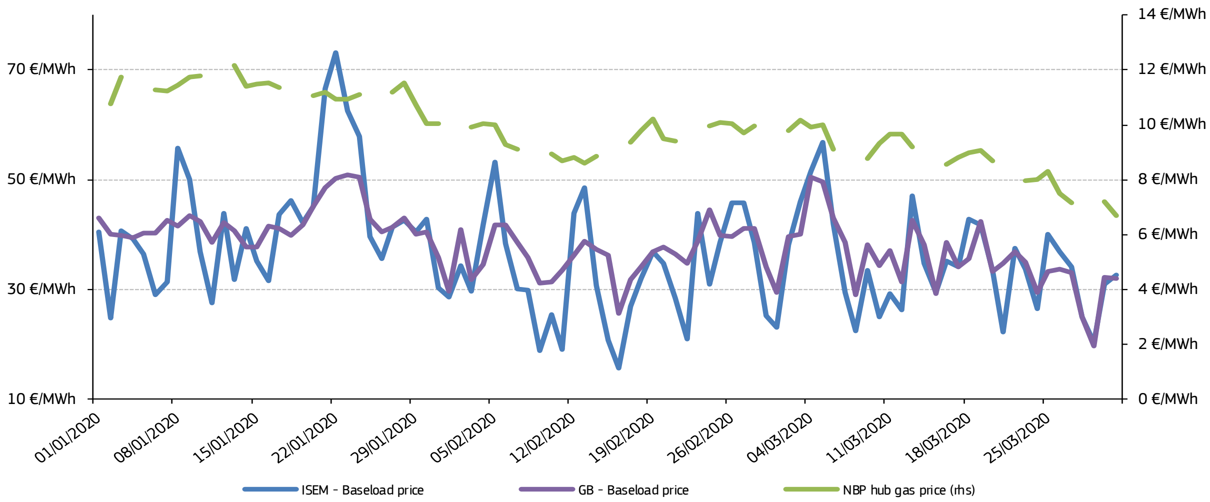
Figure 35 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO, Utility Regulator

- **Figure 36** follows the developments of daily average baseload electricity prices in Great Britain (N2EX) and Ireland (ISEM). British baseload prices hit record lows not seen since 2007 in the middle of February on the back of good wind availability and low demand. These were then surpassed on the last Sunday in March when the daily average dropped below 20 €/MWh amid intensifying lockdown measures and low weekend demand. 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 Q1 2020 (see **Figure 27**), but spiked to more than 100 €/MWh for several hours on 21 January when low wind availability coincided with cold weather and the evening demand peak.

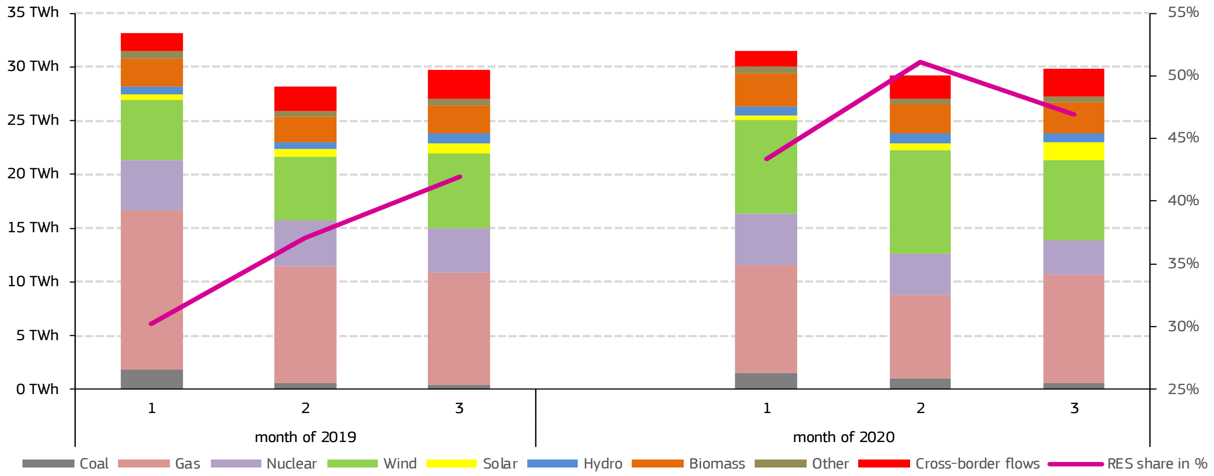
Figure 36 – Daily average electricity prices on the day-ahead market in Great Britain and Ireland



Source: Nord Pool N2EX, SEMO

- **Figure 37** compares the monthly electricity generation mix in the UK between the reference quarter and the quarter a year before. The increased coal-firing activity reported in January and February, which took place despite deeply unfavourable margins (see **Figure 26**), was most likely the result of a need to deplete remaining fuel stocks at units destined for closure. Roughly 3 GW of coal capacity was retired in Great Britain at the end of Q1 2020, leaving 5 GW of remaining capacity at three sites. One additional power plant is located in Northern Ireland.
- British electricity generation was unchanged year-on-year in Q1 2020, as higher wind and biomass generation compensated for a drop in gas and nuclear output. This development also increased the share of renewable energy sources in the power mix to 46% in the reference quarter (from 36% in Q1 2019). The combined share of gas and coal in the mix, meanwhile, declined from 46% to 37% on the back of falling gas generation.

Figure 37 – Monthly evolution of the UK electricity generation mix in Q1 of 2019 and 2020

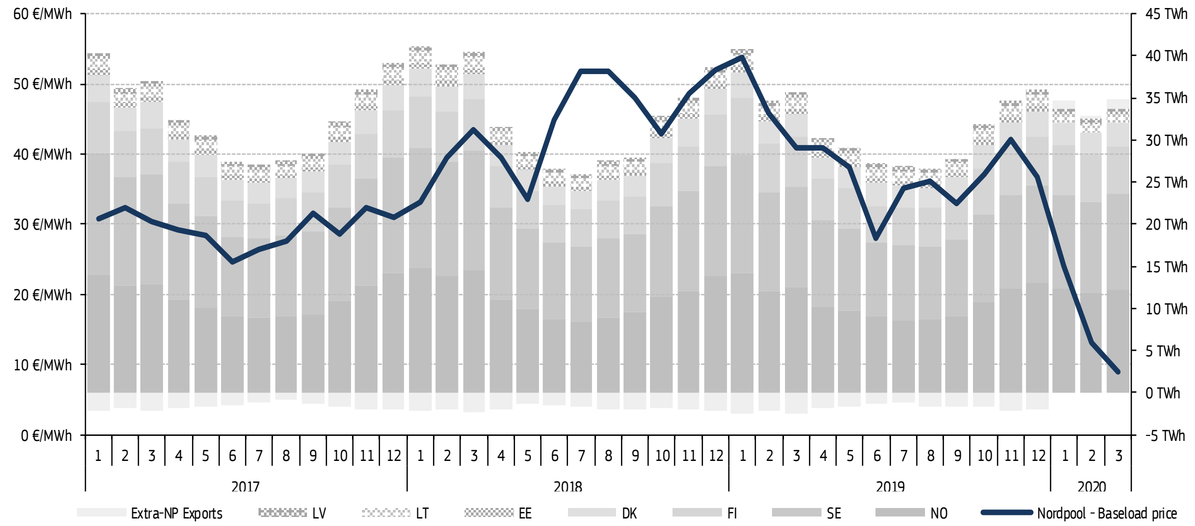


Source: ENTSO-E, Eurostat. Positive values of cross-border flows indicate net imports. Data represent net generation.

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

- As shown in **Figure 38,** the average monthly baseload price in the Nord Pool market went into freefall during the reference quarter on the back of mild and wet weather which kept demand low and hydro stocks at high levels. In addition, surging wind capacities and good win availability in Norway and Sweden weighed on baseload prices as well. The monthly average baseload went from 24 €/MWh in January, to 13 €/MWh in February, to 9 €/MWh in March. Compared to Q4 2019, the average system baseload price declined by 60% to 15 €/MWh in the reference quarter. Trading activity was little changed compared to the previous Q1.
- With the decommissioning of a coal-fired CHP unit in Stockholm in April, Sweden became the third EU Member State to exclude coal from its power mix. The move came two years ahead of schedule.

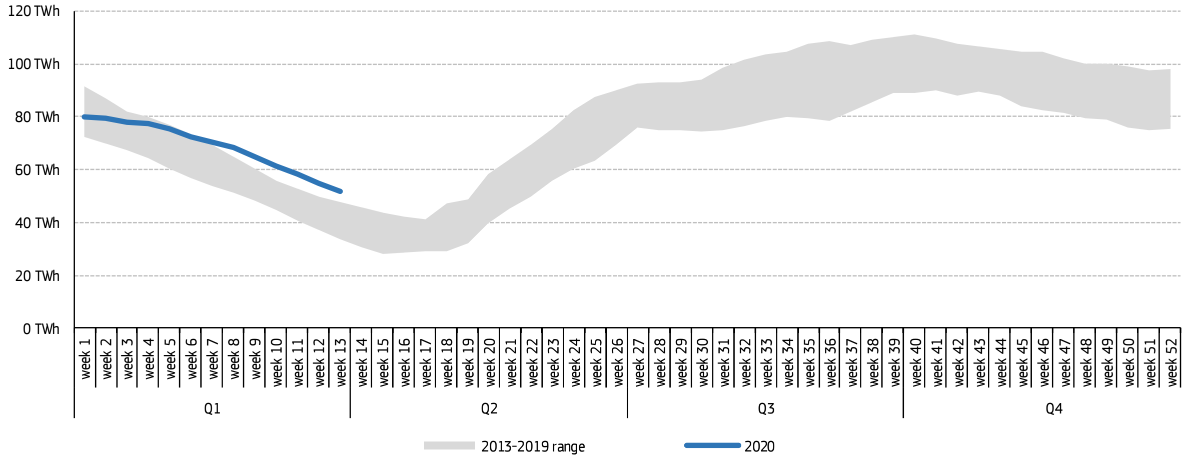
Figure 38 – Monthly electricity exchange traded volumes and the average day-ahead wholesale prices in Northern Europe



Source: Nord Pool spot market

- **Figure 39** 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. Hydro stocks in the region started the year at healthy levels amid high wind generation across Norway, Sweden and Denmark, above-average temperatures and plenty of rainfall. These conditions persisted in February, keeping the stocks at record high levels. The drawdown on hydro reservoirs accelerated in March as wind output eased and operators of hydro capacities took advantage of a more volatile price environment caused by interconnection issues. Nevertheless, the reservoir stocks finished the reference quarter at elevated levels thanks to the surplus from previous two months. The total hydro generation in the region jumped by 5 TWh year-on-year in Q1 2020, contributing to the record net exports of the region (see **Figure 30**).

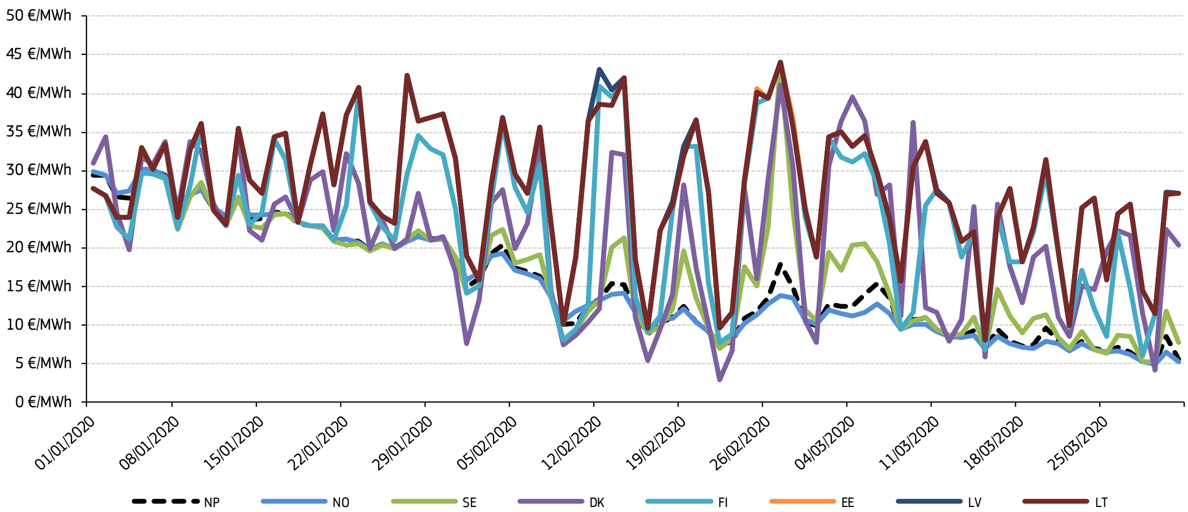
Figure 39 – Nordic hydro reservoir levels in 2020, compared to the range of 2013-2019



Source: Nord Pool spot market

- **Figure 40** shows that average daily prices across Northern Europe in Q1 2020 continued to display a high degree of divergence, as in previous quarters. The Baltic region and Finland, which both suffer from considerable structural deficits (see **Figure 31**), registered nearly permanent premiums over the system contract. These culminated in February when Sweden and Denmark joined the group of higher-priced markets, amid interconnection restrictions between Norway and Sweden. Record high wind generation brought average Danish prices below the system level on several occasions, especially in stormy February. Norway reported daily baseload prices at or below the system price level during the reference quarter.
- Contributing to the net importer position of Finland and the Baltics were flows from the Russian and Belarusian zones, which decreased measurably to 2.0 TWh in Q1 2020 (compared to 3.5 TWh in Q1 2019). This was driven mainly by lower demand in Finland, which was affected by a prolonged paper mill strike.

Figure 40 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

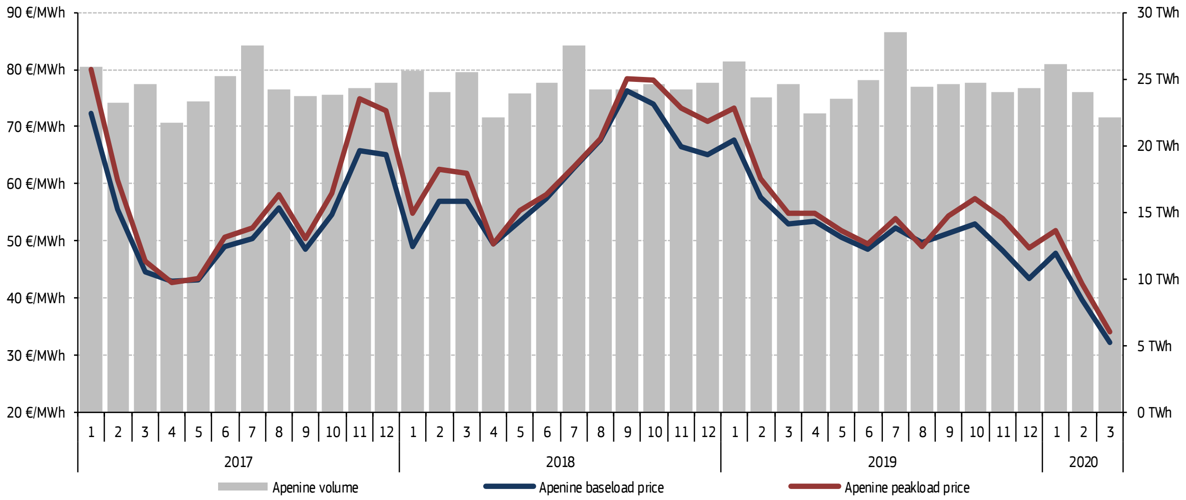


Source: Nord Pool spot market

4.4 Apennine Peninsula (Italy, Malta)

- Italian monthly average baseload electricity prices (**Figure 41**) followed a declining trajectory during the reference quarter. The drivers were high hydro generation, mild weather, declining gas prices and the demand shock associated with lockdown restrictions, which affected Italy since the beginning of March. The average monthly baseload price slid to 32 €/MWh in the final month of the reference quarter, equalling record lows from 2016. The average baseload price in Q1 2020 decreased by a third compared to Q4 2019 to 40 €/MWh. Meanwhile, the peakload electricity contract saw the premium over its baseload peer narrowing to less than 2 €/MWh in March, in line with usual seasonal developments. Trading volumes were little changed compared to the previous Q1.

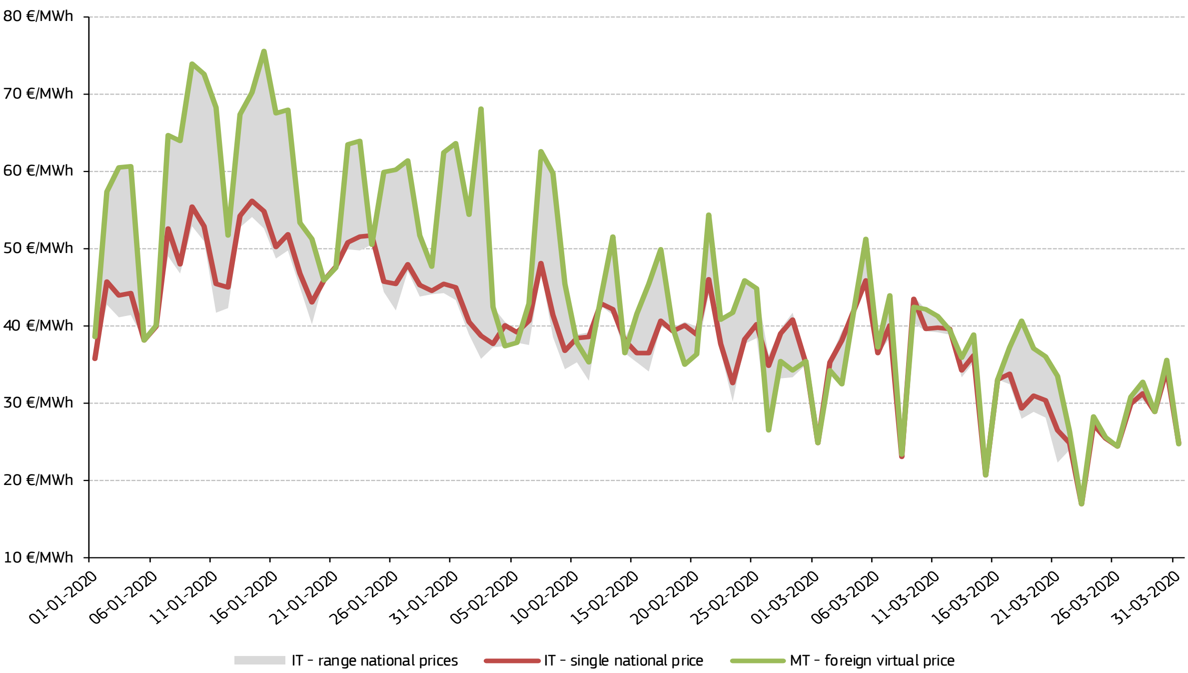
Figure 41 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy



Source: GME (IPEX)

- **Figure 42** shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. The first quarter of 2020 witnessed a steady slide in prices, in line with developments in the gas market. March saw daily prices dipping below 30 €/MWh amid severe lockdown measures which depressed demand.
- 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 42**, prices in the Maltese zone mostly followed the Italian average during Q1 2020 and formed the upper boundary of regional prices, especially in January and February. As the health crisis unfolded and demand dropped, price differences almost disappeared.
- A new 600 MW subsea interconnector with Montenegro, put into operation at the end of 2019, saw mixed flows in Q1 2020, with exports in the Montenegrin direction prevailing in the first two months of the year and Italian imports taking the upper hand afterwards.

Figure 42 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

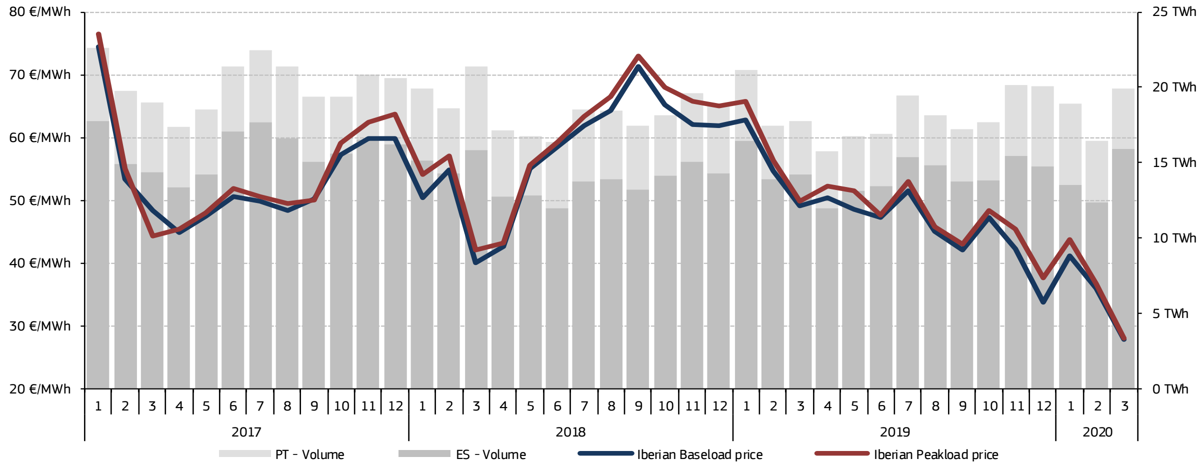


Source: GME (IPEX)

4.5 Iberian Peninsula (Spain and Portugal)

- **Figure 43** reports on the monthly average baseload and peakload contracts in Spain and Portugal. The region went through a development similar to Italy, if more extreme in both ways. The average baseload price in January went up 22% month-on-month to 41 €/MWh amid a tighter supply-demand balance. But rising temperatures, falling gas prices and solid hydro generation pushed baseload power under 36 €/MWh in February. The trend was exacerbated in March, amid economic disruptions caused by the spreading coronavirus and high renewable generation, which caused the monthly average to dive below 28 €/MWh, a four-year low. Compared to Q4 2019, the average baseload price declined by 15% to 35 €/MWh in the reference quarter. Trading activity was 6% lower compared to the previous Q1.

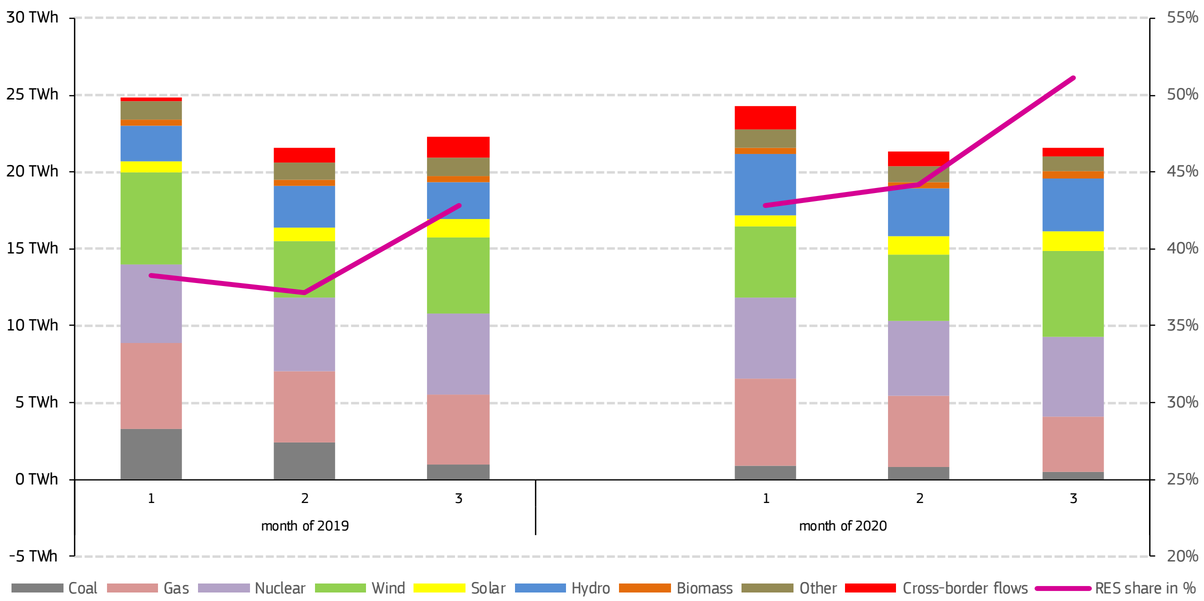
Figure 43 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula



Source: Platts, OMEL, DGEG

- **Figure 44** displays the evolution of the monthly electricity generation mix in Spain during the first quarter of 2020, as well as during the same period of the previous year. Thanks to improved hydro generation, the share of renewable electricity sources reached 46% on average in the reference quarter, up from 39% a year before. In March, renewables breached the 50% threshold in the mix. The combined share of coal and gas in the mix shrank from 33% in Q1 2019 to 25% in Q1 2020 as increased hydro generation and falling demand left smaller space for thermal plants. Both coal and gas were displaced in the process. The share of nuclear energy in Spain's mix, at 24%, was a percentage point higher compared to Q1 2019.

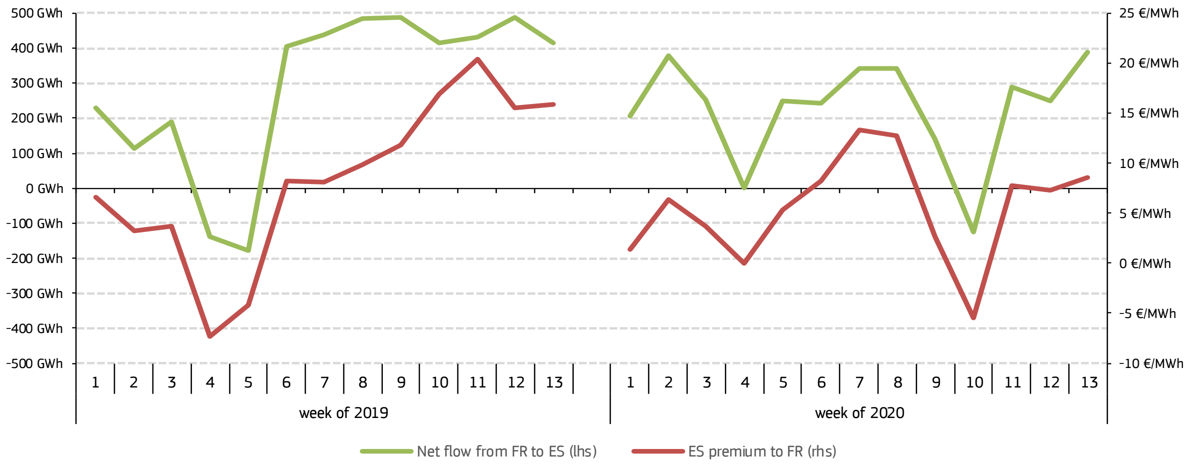
Figure 44 – Monthly evolution of the electricity generation mix in Spain in Q1 of 2019 and 2020



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

- **Figure 45** shows weekly electricity flows between France and Spain and price differentials between the two bidding zones. With the exception of the end of February and the beginning of March, day-ahead electricity was cheaper in France than in Spain in Q1 2020. Cross-border electricity flows generally followed price differentials, adding up to 3 TWh of net imports from France (down from 4 TWh in the previous Q1). Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.
- Bilateral trade with Morocco in Q1 2020 resulted in net imports of 15 GWh to Spain.

Figure 45 – Weekly flows between France and Spain and price differentials between them

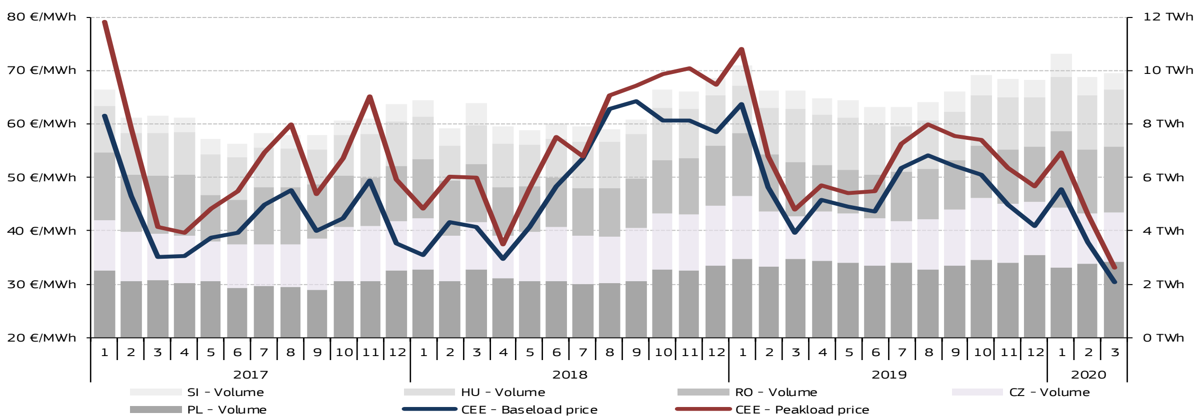


Source: ENTSO-E, OMEL, Platts

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

- **Figure 46** shows that average monthly prices for baseload power in Central Eastern Europe increased at the beginning of 2020 amid tighter supply conditions, but resumed their decrease in February and March, in line with developments in other regions. The average baseload spot contract in the region went from 48 €/MWh in January to 37 €/MWh in February to 30 €/MWh in March, pushed down by elevated wind generation in Poland, warm weather (see **Figure 2**) and the covid-related demand shock at the end of the reference quarter. The premium of peakload monthly averages over their baseload peers narrowed to less than 3 €/MWh at the end of the reference quarter, in line with typical seasonal patterns. When compared to Q4 2019, the average baseload price in the reference quarter fell by 15% to 39 €/MWh. Traded volumes in the reference quarter rose by 6% compared to Q1 2019.
- Relatively high carbon prices continued to put a strain on local lignite and coal power plants, forcing the region to import 5 TWh of electricity in the reference quarter on a net basis, up from 1 TWh a year earlier. Poland alone increased its net imports to nearly 3 TWh in Q1 2020. Germany, Austria, Nord Pool markets and Ukraine were the largest sources of inflows into the region.

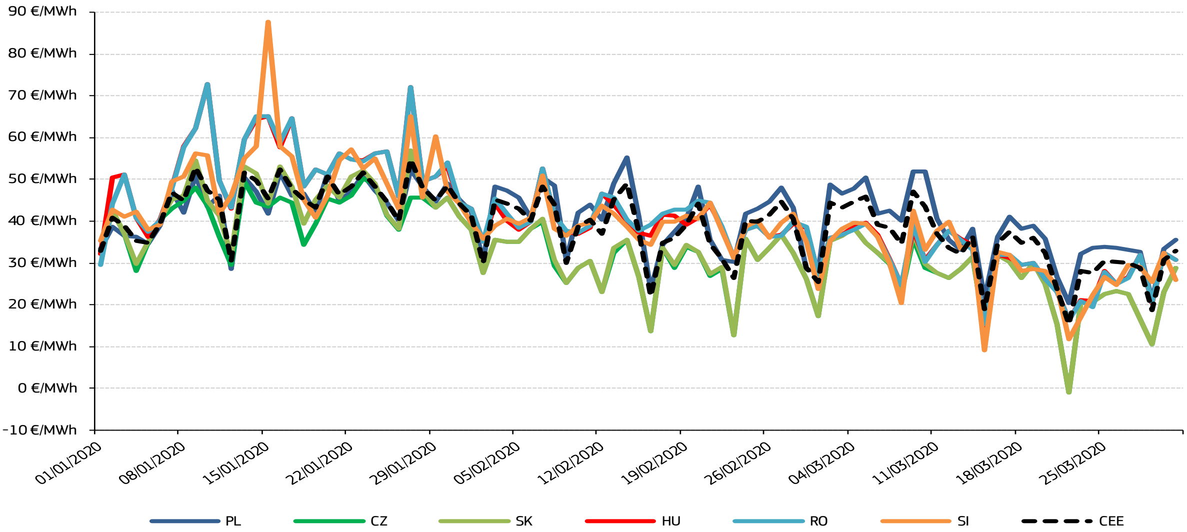
Figure 46 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)



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

- **Figure 47** shows that apart from a few moments in January, daily average baseload prices moved in a relatively compact band in Q1 2020, with few extremes on either side of the spectrum. Price spikes in January in Hungary and Romania were caused by bouts of cold weather, low wind availability and power plant outages. The lowest prices, as usual, were reported in Czechia, the regional export powerhouse, and its well-connected neighbour Slovakia. Baseload contracts in Poland, which kept its import channels wide open in the reference quarter, increased their average premium to Czech quotes from 2 €/MWh in January to 12 €/MWh in March.

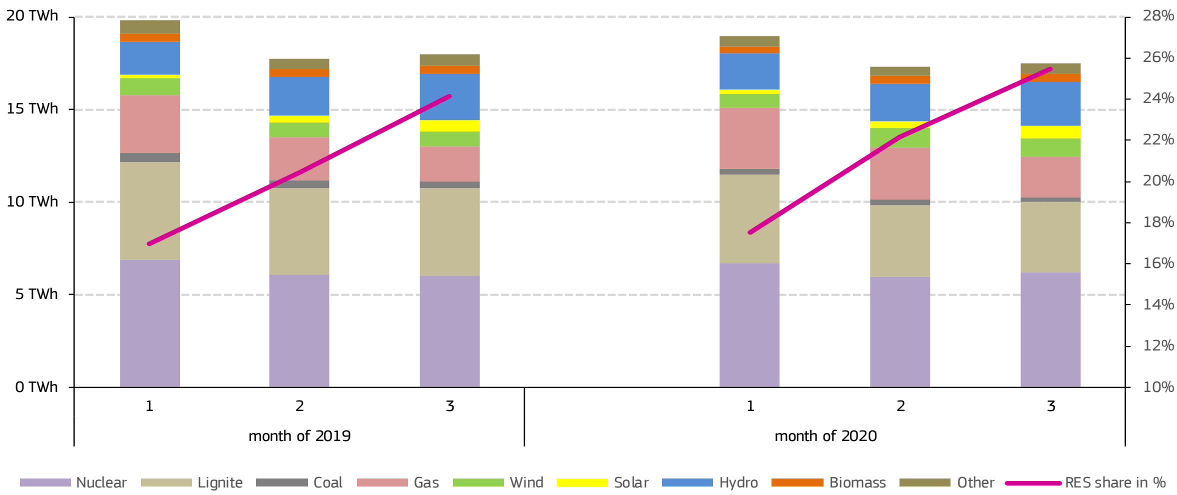
Figure 47 – Daily average power prices on the day-ahead market in the CEE region



Source: Regional power exchanges

- **Figure 48** compares the combined electricity generation mix of the CEE region (excluding Poland) between the reference quarter and the quarter a year before. Thanks to good its availability, nuclear generation increased its share of the mix to 35% in Q1 2020 (up from 34% a year before). The reduced competitiveness of lignite generation due to still relatively high CO2 prices caused the combined share of lignite and coal in the reference quarter to fall from 29% to 25% year-on-year, while gas managed to increase its share from 13% to 16% year-on-year, filling most of the gap left by coal. Renewable energy sources (wind, solar, hydro and biomass) accounted for 22% of the total electricity production in the reference quarter, up from 21% in Q1 2019. In Poland, which is analysed separately due to significant differences in the size and structure of its generation base, the combined share coal and lignite in its mix went down measurably to 67% in the reference quarter (compared to 72% in Q1 2019), while renewables increased their share from 18% to 22% year-on-year thanks to higher wind and biomass generation. Gas increased its share in the mix from 9% to 10% year-on-year, demonstrating some coal-to-gas switching potential in the market. This should be helped by a new 450 MW CCGT unit at Stalowa Wola, completed in March.

Figure 48 – Monthly evolution of the electricity generation mix in the CEE region (excluding Poland) in Q1 of 2019 and 2020

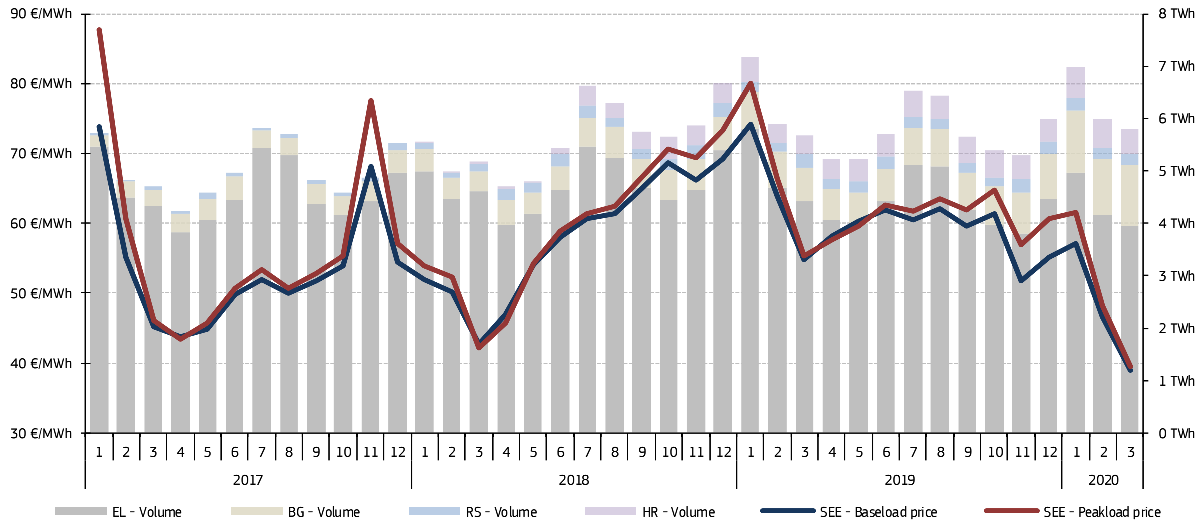


Source: ENTSO-E.

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

- **Figure 49** shows that the trade-weighted monthly average baseload prices in the SEE region headed lower during the reference quarter, driven mainly by falling prices across the region and mainly in Greece (by far the most liquid market). In January, the supply-demand balance tightened slightly amid high demand and falling lignite generation burdened by increased carbon costs. The situation improved markedly during the rest of the reference quarter, in line with typical seasonal patterns. The regional monthly average finished the quarter below 39 €/MWh, the lowest level since August 2016.

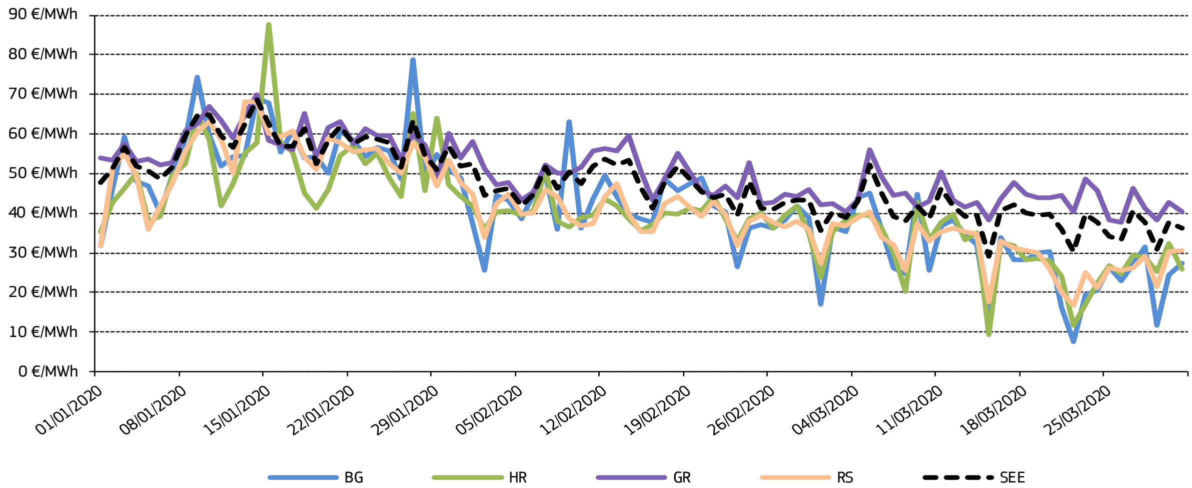
Figure 49 – Monthly traded volumes and baseload prices in South-Eastern Europe (SEE)



Source: IBEX, LAGIE, CROPEX, SEEPEX

- Apart from Greece, daily baseload price movements in individual markets were relatively well synchronized during Q1 2020, as shown in **Figure 50**. Prices in Croatia and Serbia gradually decreased in the reference quarter and were on average 13-14% lower compared to Q4 2019. Bulgaria witnessed more volatility and a slightly smaller decrease of 11% compared to Q4 2019. Greek daily spot prices distinctly diverged from the rest of the region in February and even during the lockdown in March, keeping their distance at about 10 €/MWh towards the end of the quarter.

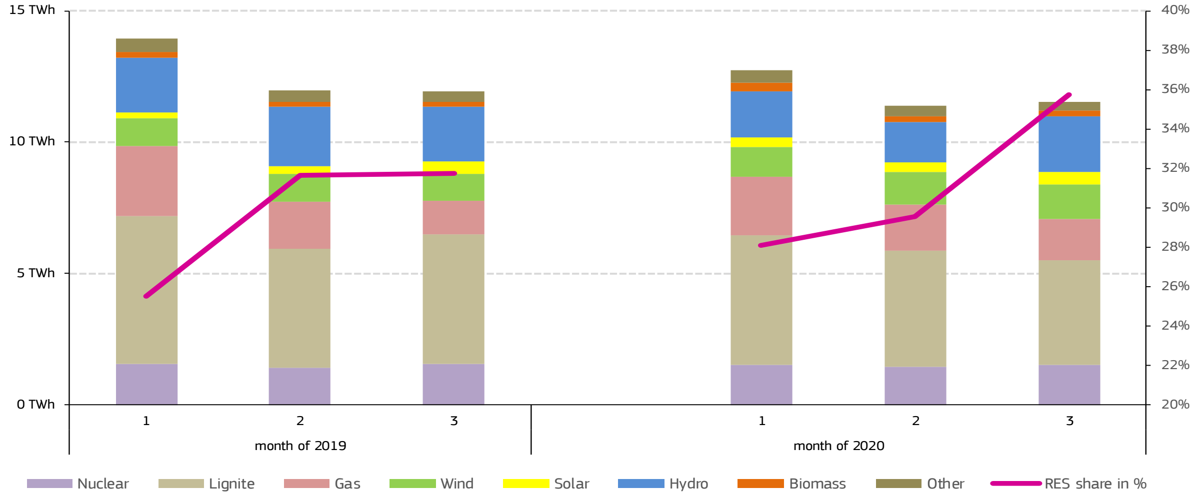
Figure 50 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia



Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 51** compares the combined electricity generation mix of the SEE region between the reference quarter and the quarter a year before. Falling lignite generation, which has difficulty coping with current CO2 prices and cannot be replaced by gas due to limited capacities, drove down the total generation by almost 2 TWh (or 6%) year-on-year and necessitated more imports. The share of renewables increased from 30% to 31% year-on-year thanks to rising wind generation. The combined share of coal and gas was fell to 53% (from 55% in the previous Q1).

Figure 51 – Monthly evolution of the electricity generation mix in the SEE region in Q1 of 2019 and 2020



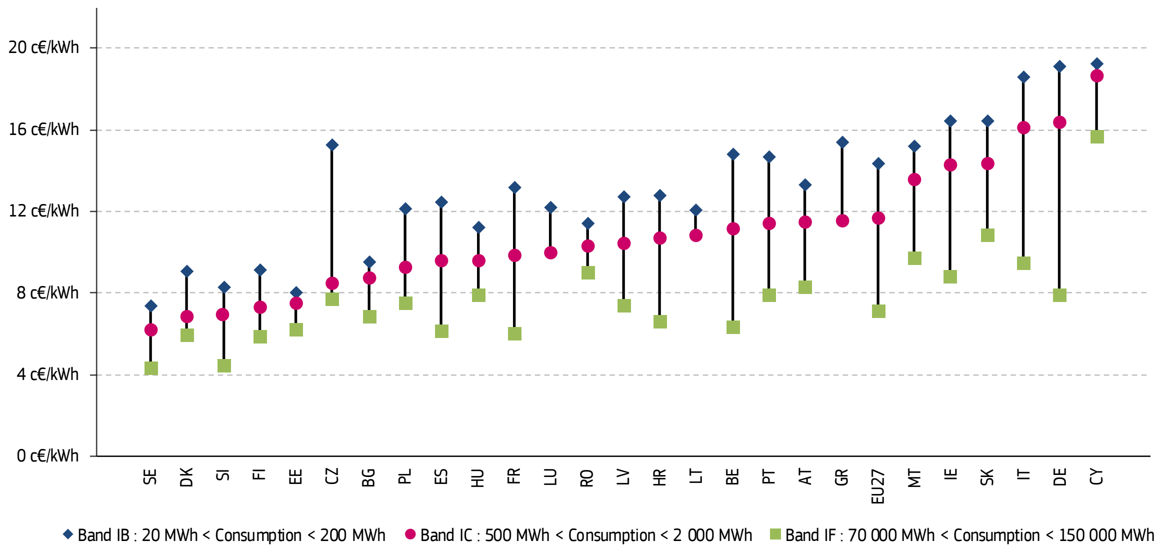
Source: ENTSO-E.

5 Retail markets

5.1 Retail electricity markets in the EU

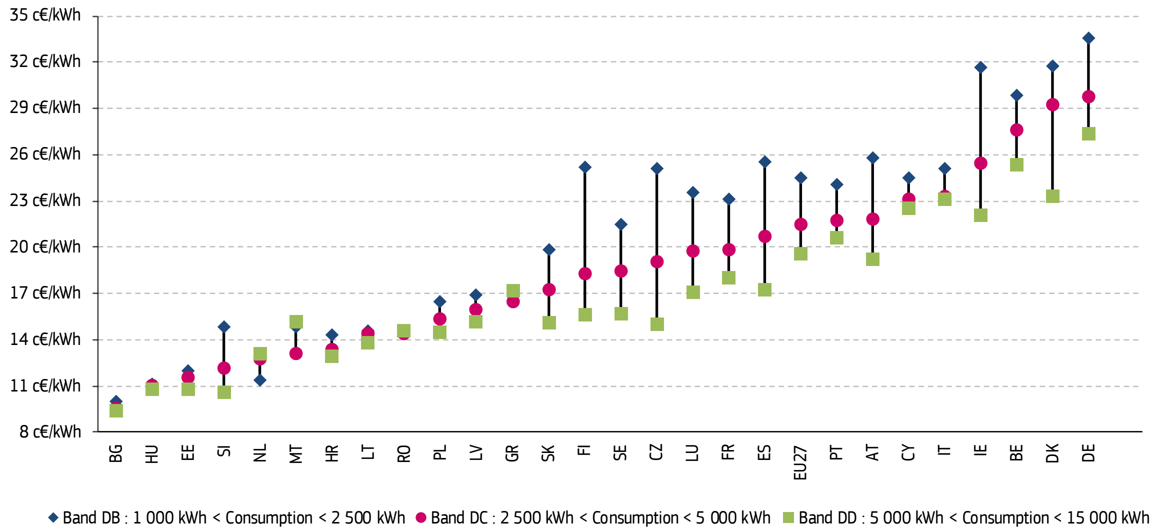
- **Figures 52 and 53** display the estimated retail prices in March 2020 in the 27 EU Member States for industrial customers and households. Prices are displayed for three different levels of annual electricity consumption for both consumer types (Eurostat bands IB, IC and IF for industrial customers 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 Cyprus (19.2 c€/kWh), Germany (19.1 c€/kWh) and Italy (18.6 c€/kWh), followed by Slovakia and Ireland (both 16.4 c€/kWh). The lowest prices in the same category were assessed to be in Sweden (7.4 c€/kWh) and Estonia (8.0 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 (15.6 c€/kWh), Slovakia (10.8 c€/kWh) and Malta (9.9 c€/kWh). Sweden (4.2 c€/kWh) was assumed to have the lowest prices, followed by Slovenia. The ratio of the highest to lowest price for large industrial consumers was 4:1 for this consumer type. Compared to March 2019, the average assessed EU27 retail electricity price for the IF band decreased by 8% to 7.1 c€/kWh.
- In March 2020, Germany (27.3 c€/kWh) was assessed as having the highest electricity price for large household consumers (band DD), followed by Belgium (25.3 c€/kWh), and with Denmark (23.3 c€/kWh) in the third place. The lowest prices for big households were calculated for Bulgaria (9.4 c€/kWh) and Slovenia (10.6 c€/kWh). In the case of small households, Germany was again evaluated as having the highest price (33.5 c€/kWh), followed by Denmark and Ireland, while Bulgaria and Hungary found themselves again on the other side of the price spectrum. Compared to March 2019, the average assessed EU27 retail electricity price for the DD band decreased by 1% to 19.6 c€/kWh.

Figure 52 – Industrial electricity prices, March 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 signifcant changes in the taxation structure affecting different sectors unevenly.

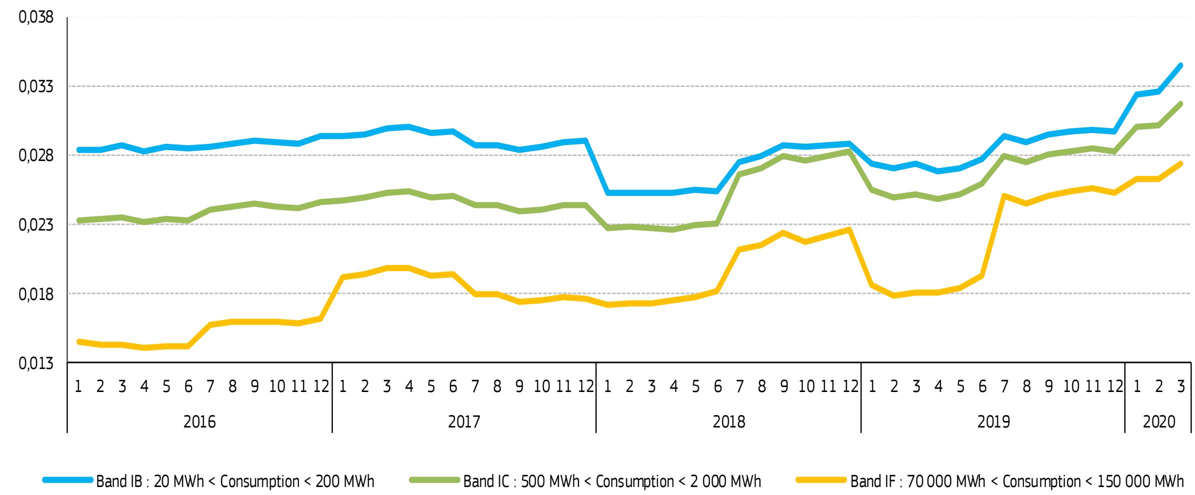
Figure 53 – Household electricity prices, March 2020 – all taxes included



Source: Eurostat, DG ENER

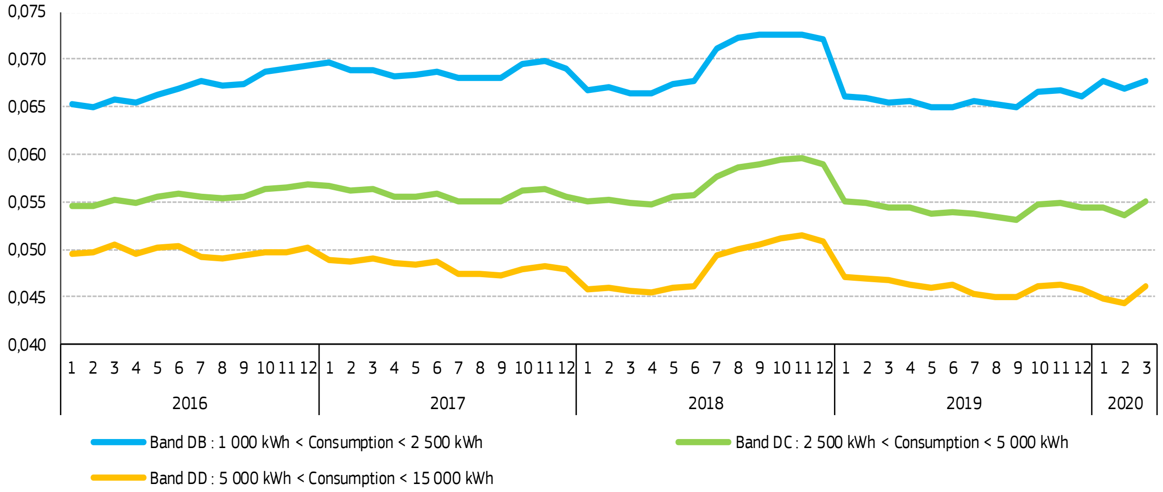
- **Figures 54 and 55** display the convergence of retail prices across the EU27 over time, by depicting their standard deviation. All end-user prices for the industry showed rising levels of price divergence throughout the reference quarter in comparison with 2019, with small- and medium-sized businesses being affected the most. In all three categories, price convergence reached record low levels, underlining diverging developments in different European wholesale markets.
- In the case of households, price convergence stabilized more or less at Q4 2019 levels. 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 54 – Standard deviation of retail electricity prices in the EU27 for industrial consumers



Source: Eurostat, DG ENER

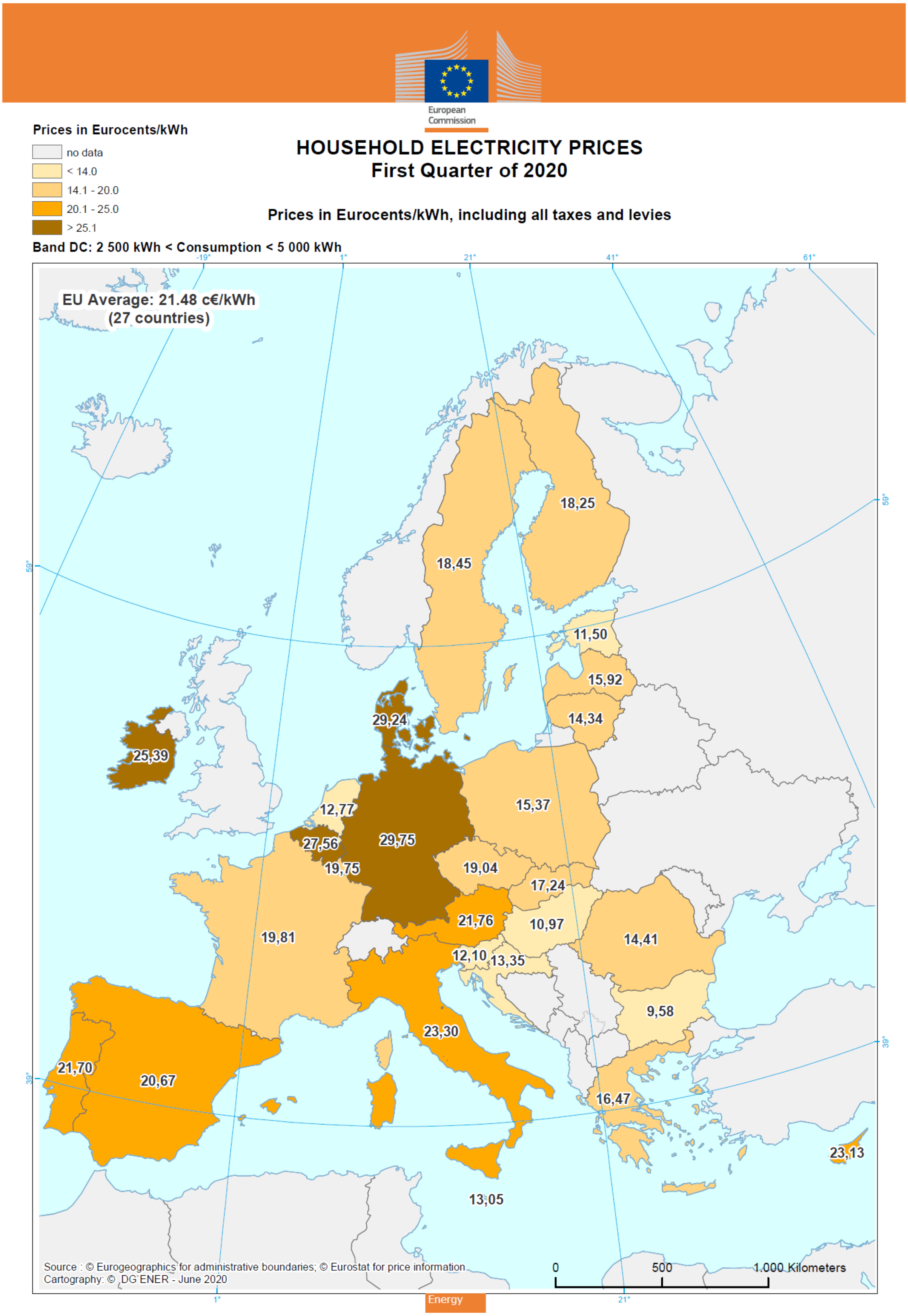
Figure 55 – Standard deviation of retail electricity prices in the EU27 for household consumers



Source: Eurostat, DG ENER

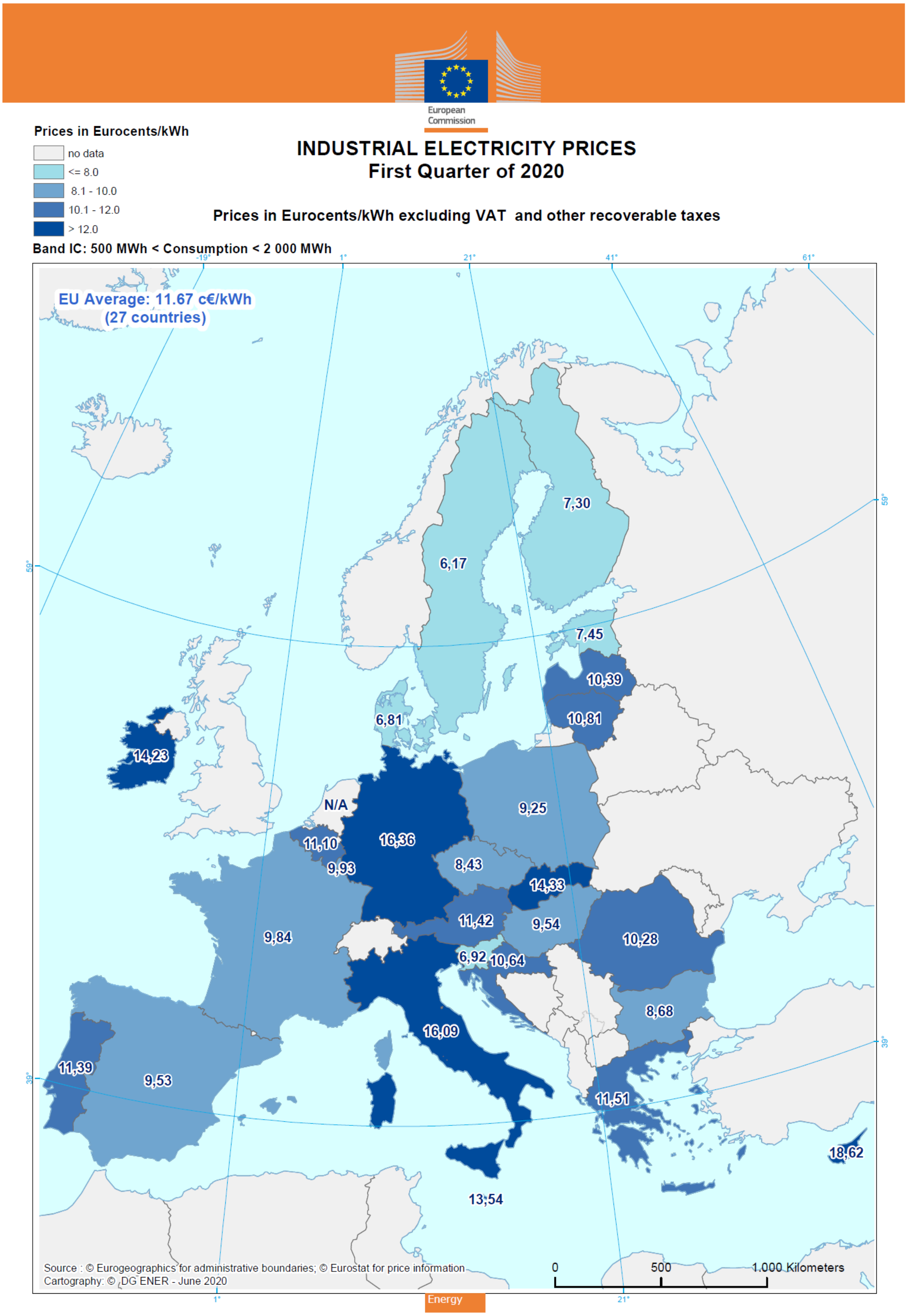
- **Figures 56 and 57** display the estimated electricity prices paid by EU households and industrial customers with a medium level of annual electricity consumption in the last month of Q1 2020. In the case of household prices, Germany topped the list (29.75 c€/kWh), followed by Denmark and Belgium. 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 March 2019. The largest year-on-year increases in the household category were assessed in Poland and Lithuania (+14%), followed by France (+11%). The biggest year-on-year falls were estimated for the Netherlands (-38%, see **Figure 58** for more details) and Slovenia (-26%).
- In the case of mid-sized industrial consumers, Sweden was assessed to have the most competitive price in Q1 2020, followed by Denmark and with Slovenia taking the third place. Meanwhile, Italy and Germany stood at the other end of the spectrum. At 11.67 c€/kWh, the average retail price for industrial customers in the EU27 in the reference period fell by 3% compared to Q1 2019.

Figure 56 – Household Electricity Prices, first quarter of 2020



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

Figure 57 – Industrial Electricity Prices, first quarter of 2020



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

- **Figure 58** 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 March 2020, the highest prices were observed in Berlin and Copenhagen (33.4 and 30.0 c€/kWh, respectively) where energy taxes accounted for approximately 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 (11.2 c€/kWh and 11.6 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 53**. Non-Member States in Europe's east tend to have lower prices. Thus, electricity for an average household in Kiev is seven times cheaper than for one in Berlin.

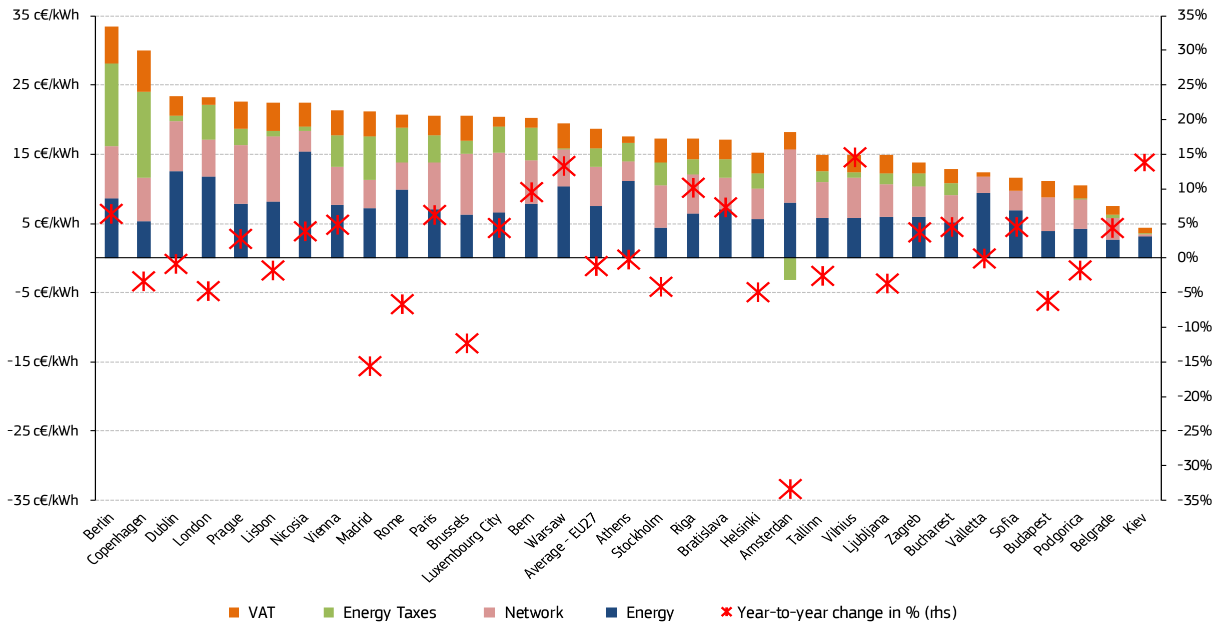
- The highest levels of the energy component in Europe were reported from Nicosia, Dublin and London (12-16 c€/kWh), cities surrounded by wholesale markets with higher prices compared to the EU27 average. The lowest levels of the energy component (4-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Bucharest) or with a high degree of renewable production (Copenhagen, Stockholm). The EU27 average for the energy component was 7.6 c€/kWh (almost unchanged from March 2019). Thus, the general decrease in European wholesale prices witnessed during 2019 has not been fully passed through to retail prices yet. 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 18**).

- 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 (up 2% from March 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 the local authorities.

- 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 53**.

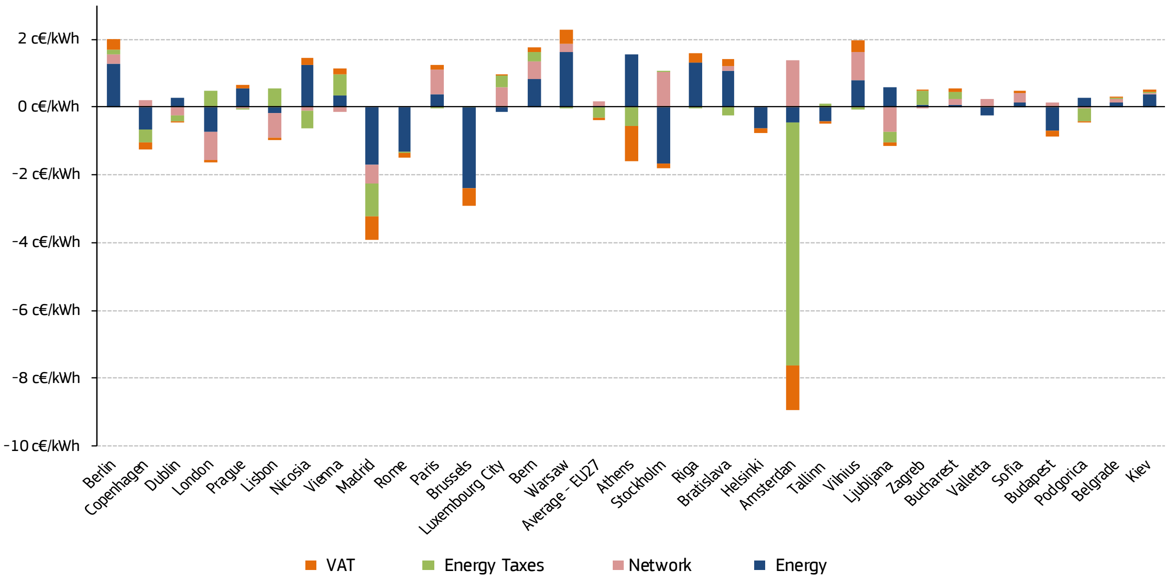
Figure 58 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, March 2020



Source: Vaasaett

- Compared to the same month of the previous year, the largest price increases in relative terms in March 2020 were observed in Vilnius (+15%), followed by Kiev (+14%) and Warsaw (+13%). As shown in **Figure 59**, the distribution component was the biggest contributor to rising prices in Vilnius. In Warsaw and Kiev, rising prices were driven by the energy component. 13 of the EU27 capitals reported prices lower or unchanged compared to the same month of the previous year, with Amsterdam (-33%), Madrid (-16%) and Brussels (-12%) 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 Belgian 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 59 – Year-to-year change in electricity prices by cost components in the European capital cities comparing March 2020 with March 2019

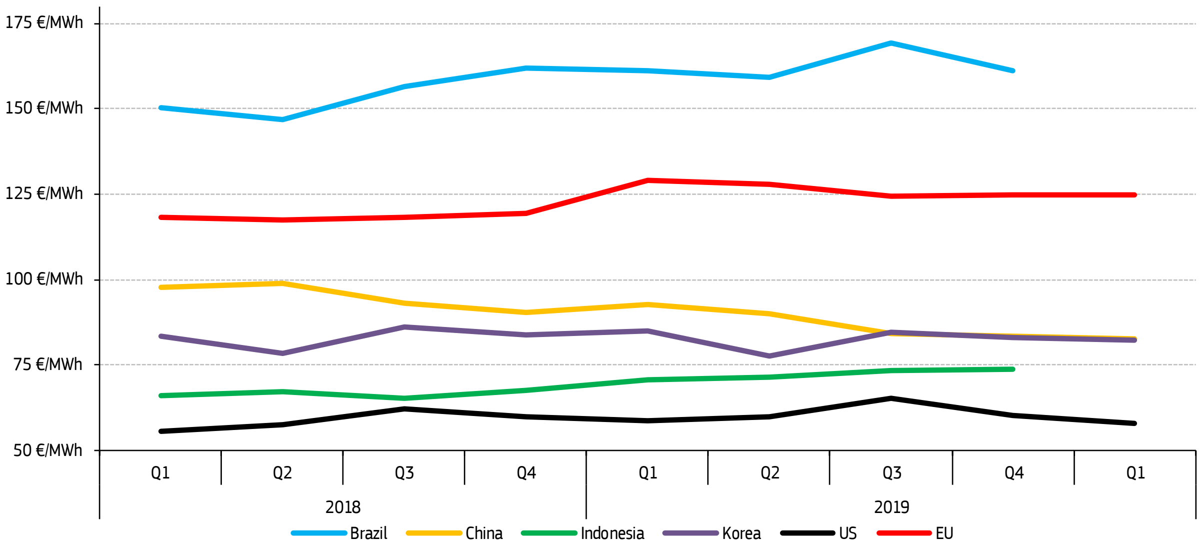


Source: Vaasaett

5.2 International comparison of retail electricity prices

- **Figure 60** 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.
- Prices in the EU27 remained unchanged in Q1 2020 compared to the previous quarter. Other regions were assessed to experience decreases, with the biggest drop occurring in the United States (-4% quarter-to-quarter in euro terms). Industrial power prices in China and Korea fell in tandem by 1% quarter-to-quarter and were about 51% lower than in the EU27.

Figure 60 – 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.

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 1975-2016) 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.