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HIGHLIGHTS OF THE REPORT

• Strong downward pressure on gas spot prices thanks to plentiful pipeline supplies and record LNG deliveries led to intensive coal-to-gas switching across the EU in Q1 2019, as coal was disadvantaged by relatively high CO2 prices. Gas-fired generation reached a record volume of 148 TWh, higher than in any previous first quarter.

• The share of coal in the EU power mix continued to decline, mainly at the expense of hard coal output, and reached the lowest level on record in March (13.3%), despite rapidly falling coal prices.

• The withdrawal of emission allowances from the market into the Market Stability Reserve, aimed at addressing the current surplus of allowances, started in January. However, uncertainty surrounding the Brexit issue was the main factor influencing CO2 prices in the quarter.

• Wholesale electricity prices fell across all EU markets in Q1 2019, with the European Power Benchmark declining by 21% compared to the previous quarter, thanks to mild weather conditions in February and March, lower energy commodity prices and good renewable output.

• The renewables sector continued to increase its share in the power mix, reaching 31% in the reference quarter, with wind generation leading the rise and breaking records especially in March. Increases in wind, solar and biomass output more than compensated for weak hydro generation, caused by low reservoir levels across the continent.

• The 1000MW UK-Belgium ‘Nemo Link’ interconnector started operating in January 2019, becoming the UK’s first electrical interconnector with Belgium and its fifth link with the continent. This enhances the potential of the CWE region, which cemented its position as a leading exporter of power to other regions with higher prices during Q1 2019.

• The trend of rising retail price divergence across the EU began to slowly reverse in Q1 2019, both for households and industry. The average industrial electricity price in the EU decreased by 1.1% compared to last quarter. In the household sector, Belgium, Germany and Denmark were the countries with highest prices, whereas Bulgaria and Hungary had the lowest prices.
EXECUTIVE SUMMARY

- Even though economic growth continued to expand in Q1 2019, electricity consumption decreased by approximately 2% year-on-year as milder winter and stagnating industrial production curbed demand. Of the major economies, power consumption fell the most in the UK (-5.5%), followed by Italy (-4.4%), France (-4%), Spain (-3.5%), Germany (-1.7%) and Poland (-1.4%).

- Spot coal prices fell by almost 30% during Q1 2019, finishing the quarter at 53.24 €/Mt, as stocks at the Dutch terminals hovered close to multiyear maximums and low prices of gas depressed the market. Spot gas prices, in turn, were pushed down by a high volume of LNG and pipeline imports, high storage levels and weak Asian demand. The TTF spot contract weakened by 34% during the reference period, finishing the quarter at 14.70 €/MWh, which was 27% lower than at the same time last year.

- The emission allowance market went through another volatile period in Q1 2019, trading in a range between 18 and 25 €/t, which was still a bit narrower than in the previous quarter. Overall, CO2 spot prices in the reference period fell by 14.3%, registering their first such decline since Q2 2017. However, at the end of March 2019 they nearly doubled compared to their level from March 2018. Uncertainty surrounding the UK’s participation in the EU EUTS was the main factor influencing CO2 prices in the quarter. Whenever the chances of a no-deal Brexit increased, prices were under downward pressure.

- In Q1 2019 the estimated EU import bill for thermal coal amounted to €2.4 billion, 1.2% lower compared to Q1 2018. The amount of imported thermal coal in the reference quarter came nearly 3% lower compared to the same quarter of 2018 and almost 11% lower compared to Q1 2017, which reflects a gradually decreasing role of the fuel in the EU generation mix. The largest share of extra-EU thermal coal imports came from Russia, accounting for 54% of the total. Russia has noticeably increased its import share over the last four years.

- The EU-wide European Power Benchmark of wholesale baseload prices reached 48.9 €/MWh in the reference quarter, which represented an increase of 7.7% in year-on-year comparison. Matched against the value from Q4 2018 however, the wholesale benchmark fell by 20.7%. In Q1 2019 the lowest prices could be found in Germany and Luxembourg (both 40.9 €/MWh) and Denmark (42.9 €/MWh) which benefited from ample fossil-fuel and/or renewable generation capacities. Wholesale prices in Italy, the Balkans and on the Iberian Peninsula registered lower falls than in Germany as weak hydro generation in those regions limited the supply side.

- Rising CO2 prices materially affected the EU power mix, as less CO2-intensive gas generation has gained prominence, with 19.2% share in the overall EU power mix in Q1 2019 (compared to 15.2% in Q1 2018 and 12.6% in Q1 2016), at the expense of hard coal and lignite generation, which saw its combined share reduced to 15.8% in the reference quarter (from 19% in Q1 2018 and 20.1% in Q1 2016). Between hard coal and lignite, the latter displays more resilience under the current circumstances, as lignite generation has lower marginal costs per unit of energy produced. The outlook for coal-to-gas switching is further improving. However, further coal-to-gas switching could be limited by lower power demand in summer months or high renewable output.

- In Q1 2019 the trend of a gradually rising role of renewable generation in the EU power mix continued, with the combined share of hydro, biomass, wind and solar reaching 31%. The share of hydro generation reached 10.1% in Q1 2019, lower than in any of the previous Q1 in at least last four years, as a dry summer last year and scarce rainfall in the reference period negatively affected reservoir levels. In contrast, wind-powered electricity generation recorded its best Q1 yet, gaining a 16% share in the overall mix and becoming a key driver of renewable generation growth.

- The number of hours with negative wholesale prices in Q1 2019 was relatively high compared to previous quarters. Most of hourly negative prices occurred in March, a month of strong wind generation and mild weather conditions, and was concentrated mainly in the German and neighbouring markets.

- The Central Western European region cemented its position as the biggest electricity exporter to the continent, having plentiful generation capacities, the most competitive prices and a good position to supply all the other regions. Net export flows grew to 22.5 TWh in Q1 2019 (+14% compared to Q1 2018). Strong renewable generation in the region and recovering performance of the French nuclear fleet contributed to this result. The Nordic region lost its traditional position of a net exporter due to low hydro reservoir levels. Imports from the Russian market to Finland and the Baltics rose by more than 50% compared to Q1 2018 and cost €186 million (+139% year-on-year).

- In March 2019, Belgium (31.2 c€/kWh) reported the highest median household price for electricity consumers, overtaking both Germany (30.8 c€/kWh) and Denmark (at 30.1 c€/kWh). Industrial consumers with large annual consumption, including most energy intensive users, paid the highest prices in the UK (117 c€/kWh) followed by Slovakia and Ireland. The lowest prices were reported by Luxembourg (3.7 c€/kWh) followed by Sweden and France.
1 Electricity market fundamentals

1.1 Demand side factors

- According to the data of the European Network of Transmission System Operators (ENTSO-E), EU-wide consumption of electricity registered an estimated 2% year-on-year decrease in Q1 2019 as milder winter and stagnating industrial production curbed demand. Of the major economies, power consumption fell the most in the UK (-5.5%), followed by Italy (-4.4%), France (-4%), Spain (-3.5%), Germany (-1.7%) and Poland (-1.4%).

- Figure 1 shows that after five previous quarters of consecutive slowdowns, the pace of economic growth in the EU-28 stabilized in the first quarter of 2019. From January to March 2019, GDP expanded by 1.5% in year-on-year comparison, which compares to 2.3% in Q1 2018.

Figure 1 – EU 28 GDP annual change (%)

![EU 28 GDP annual change](source: Eurostat)

- Figure 2 shows the monthly deviation of actual Heating Degree Days (HDDs) from the long-term average in Q1 2019. On EU-28 average, the quarter had 147 HDDs below average (which translates to 1.63 °C warmer than average per day) due to milder weather in February and March. In January on the EU-28 level, HDDs were in line with the long-term average. On a country-level, the decrease of HDDs in Q1 2019 was strongest in Lithuania, Latvia, Estonia, Denmark, and Poland, registering more than 220 HDDs below the long-term average. Whereas in Malta and Cyprus HDDs were closer to the long-term average in Q1 2019.

Figure 2 – Deviation of actual Heating Degree Days (HDDs) from the long-term average, in January–March 2019

![HDDs deviation](source: JRC)

The colder the weather, the higher the number of HDDs. Values above zero represent colder temperatures compared to the long-term average.
1.2 Supply side factors

- **Figure 3** reports on the developments in the European coal and gas prices which both continued in their slide during the entire reference period, after reaching a peak at the beginning of Q4 2018. Spot prices of both commodities took a dive under year-ahead prices at the end of January, moving in a contango position, as a sudden and sharp revision of cold weather forecasts on the continent pointed towards a milder-than-expected rest of the heating season. Spot prices then continued to decline more rapidly throughout the quarter, increasing their divergence from year-ahead contracts, on the back of high stock levels and weak demand.

- Spot coal prices, represented by the CIF ARA contract, fell by almost 30% during Q1 2019, finishing the quarter at 53.24 €/Mt, the lowest level since Q3 2016, as stocks at the Dutch terminals remained close to multiyear maximums and low prices of gas (a direct competitor fuel in the European electricity production) depressed the market. Prices were also pushed down by Russian suppliers ready to offer significant discounts to keep their market share. In addition, high amount of wind generation reduced the demand for coal. Spot gas prices, in turn, were pushed down by a high volume of LNG and pipeline imports, high storage levels and weak Asian demand. The TTF spot contract weakened by 34% during the reference period, finishing the quarter at 14.70 €/MWh, which was 27% lower than at the same time last year and the lowest level since Q3 2016.

- Year-ahead gas prices, by contrast, decreased only by 11% during the first quarter of 2019, arriving at 18.73 €/MWh at the end of the period and keeping more in line with similar declines in power futures in Germany, a key market for coal-to-gas switching. Year-ahead coal prices declined by 6% during the reference period, broadly in line with peer futures contracts in Australia.

**Figure 3 – Weekly evolution of spot and year-ahead coal and gas prices**

![Weekly evolution of spot and year-ahead coal and gas prices](image_url)

Source: S&P Global Platts

- As shown in **Figure 4**, the emission allowance market went through another volatile period in Q1 2019, trading in a range between 18 and 25 €/t, which was still a bit narrower than in the previous quarter. At the beginning of the year prices quickly dropped from their records above 25 €/t, as the effect of the Market Stability Reserve (MSR) being activated for the first time had been priced in already before, and generally mild weather conditions and weaker natural gas prices weighed prices down. Then came a reversal and the price of allowances climbed back towards record levels, pushed up by tight supply from primary auctions, colder weather boosting demand, and a relief rally after the UK parliament rejected a proposed Brexit deal with the EU. The move upwards then gradually dissipated thanks to the expectation of new allowances entering the market via German auctions, milder weather forecasts, weakening natural gas prices and uncertainty over Germany’s planned coal and lignite phase-out, which could greatly affect the demand for allowances in the longer term if the resulting surplus of unused permits were not cancelled. The downward trend continued until the end of February when fears of a no-deal Brexit abated and buyers started showing interest. Prices rebounded somewhat, finishing the quarter at 21.45 €/t. Overall, CO2 spot prices in the reference period fell by 14.3%, registering their first such decline since Q2 2017. However, at the end of March 2019 they nearly doubled compared to their level from March 2018.

- The European Commission has implemented several measures meant to shield the emission allowance market from Brexit. They aim to avoid the market being flooded by allowances issued or sold to companies by the British government when (or if) they are no longer needed by these companies. The allowances issued by a country that has notified the EU about its intention to leave the bloc are to be marked and thus distinguished from those used in the rest of the system, which should allow investors to discount their value accordingly. The UK received an exemption for allowances issued in 2018 as the EU law still applied on its territory when the allowances for 2018 were surrendered this spring. British allowances issued in 2019 would not, however, be subjected to the exemption. In another important measure, the Commission decided to temporarily suspend for the UK the free allocation and auctioning of emissions allowances, as well as the exchange of international credits, effective...
from 1 January 2019. This meant that no allowance auctions in the UK took place in Q1 2019. As a result, some UK participants in the trading system found themselves in a difficult position as they had used to borrow from their current year’s free allocation to surrender against their previous year’s obligation. The British government has said it will halt its participation in the EU ETS in the event of a no-deal Brexit. This could result in a supply overhang of carbon allowances accumulated over the last years by some participants who could see no need to retain them anymore. Developments around the issue continued to influence the market in Q2 2019.

Figure 4 – Evolution of emission allowance spot prices from Q1 2018 to Q1 2019

Source: S&P Global Platts

- Figure 5 reports on extra-EU thermal coal import sources and the monthly amounts of imports of the commodity into the EU. In the first quarter of 2019 thermal coal imports from outside the EU reached 28.8 Mt. The amount of imported coal in the reference quarter came nearly 3% lower compared to the same quarter of 2018 (29.6 Mt) and almost 11% lower compared to Q1 2017 (32.2 Mt), which reflects a gradually decreasing role of the fuel in the EU generation mix, visible even in the winter season (see Figure 9).

- In Q1 2019 the estimated EU import bill for thermal coal amounted to €2.4 billion, just 1.2% lower compared to Q1 2018, reflecting a slight year-on-year increase in import prices which compensated for the lower imported volume in the reference quarter. Looking further into the year, the decrease in the coal import bill should persist and even intensify as spot prices continued to fall in Q2 2019.

- In the first quarter of 2019 the largest share of extra-EU thermal coal imports came from Russia, accounting for 54% of the total. Russia noticeably increased its import share since the first quarter of 2016 when its thermal coal accounted for 39% of all imports (and 41% in the first quarter of 2017). This development can be explained partly by favourable shipment costs and rouble/euro exchange rate, partly by increasing production in Russia (which reached a record of 433 Mt in 2018, surpassing the Soviet maximum from 1988) and also partly by deliberate efforts of Russian producers to expand their presence in the European market, especially in Germany. The second most important thermal coal import source was Colombia, although its share fell from 18% in Q1 2018 to 11% in the reference period. In Q1 2019 USA was the third most important thermal coal trading partner of the EU as imports from this country accounted for 10% of all imports, down from 14% a year earlier. Imports from Indonesia made up 7% of EU’s total thermal coal imports, up from 5% a year earlier. South Africa accounted for 6% and Australia for 3% of EU’s thermal coal imports in the reference period.
2 European wholesale electricity markets

2.1 European wholesale electricity markets and their international comparison

- The next map shows that significant differences in wholesale electricity prices across Europe persisted in the first quarter of 2019, with a 27.1 €/MWh difference between the most expensive and cheapest market being broadly in line with last year’s figures.

- The highest average wholesale electricity prices in Q1 2019 could be observed in Greece (68 €/MWh), Ireland (61.1 €/MWh), Italy (59.4 €/MWh) and the United Kingdom (59.2 €/MWh), all of which are either traditionally significant importers of electricity and/or face limitations in cross-border transmission capacities or (in the case of the UK) apply higher CO2 prices for power generation than the rest of the EU. In contrast to the situation in Q4 2018, when Scandinavian countries registered the lowest wholesale prices in Europe, in Q1 2019 the lowest quarterly wholesale averages could be found in Germany and Luxembourg (both 40.9 €/MWh) and Denmark (42.9 €/MWh) which benefit from ample fossil-fuel and/or renewable generation capacities.

- The EU-wide European Power Benchmark of wholesale baseload prices reached 48.9 €/MWh in the reference quarter, which represented an increase of 7.7% in year-on-year comparison. Comparing with Q4 2018 however, the wholesale benchmark fell by 20.7%.

- In terms of developments in individual markets, the biggest year-on-year price swings in the upward direction took place in Romania (+54%), Bulgaria (+40%), Hungary and Greece (both +37%), whereas the biggest decreases/lowest increases could be observed in the UK (-1%), France (+7%), Belgium and the Netherlands (both +8%).
Figure 6 – Comparison of average wholesale baseload electricity prices, first quarter of 2019

Source: European wholesale power exchanges
Figure 7 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 after reaching the highest degree of convergence since several years in Q3 2018, wholesale electricity prices across different regional markets in Europe began to sharply diverge during Q1 2019. This was mainly due to the fact that during the reference period, prices in the CWE and CEE regions registered a much steeper fall than their counterparts in southern EU markets, especially Greece. Prices in Italy, the Balkans and on the Iberian Peninsula were affected by weak hydro generation.

Figure 7 – The evolution of the lowest and the highest regional wholesale electricity prices in the EU and the relative standard deviation of the regional prices

![Graph showing the evolution of the lowest and highest regional wholesale electricity prices in the EU and the relative standard deviation of the regional prices.](image)

Source: Platts, European power exchanges – As of January 2017 Platts PEP has been replaced by a calculated EU average (European Power Benchmark). In different periods minimal and maximum prices may refer to different power regions.

Figure 8 shows the evolution of the European Power Benchmark (EPB) spot wholesale electricity price contract, as well as German day-ahead baseload and year-ahead contracts in the reference period. Germany serves as a point of reference, having one of the most liquid markets in Europe with available forward curve price quotations. Both day-ahead EPB and German baseload contracts show the impact of rapidly decreasing fuel prices (coal and gas) for marginal power plants and above-average temperatures in Q1 2019. German prices, however, show a much larger volatility owing to a big influence of highly fluctuating wind generation in the market and also due to the fact that the EPB is a composite index representing a wide pool of individual markets. Year-ahead German electricity prices posted a 10% decrease in Q1 2019, similarly to year-ahead gas contracts (see Figure 3).
**Figure 8 – Weekly evolution of day-ahead and year-ahead German electricity prices**

![Weekly evolution of day-ahead and year-ahead German electricity prices](image)


- **Figure 9** shows the evolution of the electricity generation mix in the EU-28. Overall, the general trend of decreasing nuclear share and increasing role of renewables (hydro, biomass, wind and solar) and fossil fuels (combined solid fuels and gas) in the mix continued in Q1 2019. Compared to the same quarter of the previous year, in Q1 2019 the share of fossil fuels increased from 34% to 35%, while the share of renewables (hydro, biomass, wind and solar) rose from 31% to 32%. The share of nuclear went down from 28.6% to 28.2% year-on-year (compared to 31.5% in Q1 2016).

- Generally mild weather throughout the quarter limited the potential for fossil fuel generation. Within the fossil fuels complex, the effect of rising CO2 prices can be observed, as less CO2-intensive gas generation is gaining prominence, with 19.2% share in the overall mix in Q1 2019 (compared to 15.2% in Q1 2018 and 12.6% in Q1 2016), at the expense of hard coal and lignite generation, which saw its combined share reduced to 15.8% in the reference quarter (from 19% in Q1 2018 and 20.1% in Q1 2016). In fact, when strong wind generation in March 2019 pushed down demand for fossil fuel capacities, the share of hard coal and lignite in the mix dropped to the lowest level on record (13.3%).

- Between hard coal and lignite, the latter displays more resilience under the current circumstances, as lignite generation has lower marginal costs per unit of energy produced, so a higher carbon price would be required to significantly reduce its competitiveness. Nevertheless, both fuels faced declining shares in the mix in Q1 2019. In the case of hard coal, its share decreased to 7.7% from 9.8% in Q1 2018, and in the case of lignite, its share fell to 8.2% from 9.2% in Q1 2018. The distinction between hard coal- and lignite-based generation is not visible in Figure 9.
Figure 9 – Monthly electricity generation mix in EU-28

Source: ENTSO-E

- **Figure 10** depicts the evolution of the monthly renewable generation in the EU, alongside the share of renewables in the electricity generation mix. In Q1 2019 the trend of a gradually rising role of renewable generation continued, with the combined share of hydro, biomass, wind and solar reaching 31% (compared to 30% in Q1 2018 and 29.3% in Q1 2016). This was not only thanks to good weather conditions, but also owing to more than 18 GW of new wind and solar capacity additions in 2018\(^1\), which took the total combined potential of these two sources close to 300 GW across the EU. During the three months of the reference period, the share of RES moved in the range between 29.13 and 35.84%, which is not unusual as RES generation during this part of the year tends to be heavily influenced by changing factors such as hydro reservoir and precipitation levels or wind availability.

- The share of hydro generation reached 10.1% in Q1 2019, lower than in any of the previous Q1 in at least last four years, as a dry summer last year and scarce rainfall in the reference period negatively affected reservoir levels. In contrast, wind-powered electricity generation recorded its best Q1 yet, reaching a 16% share in the overall mix and becoming a key driver of renewable generation growth. The share of solar generation reached 2.6% as the number of solar radiation hours is lower during winter months, but this was still best figure for any previous Q1. The share of biomass stood at 3.2% in Q1 2019, compared to 2.7% in Q1 2018.

\(^1\) According to data from SolarPower Europe and WindEurope.
Figures 11 and 12 report on the profitability of gas-fired and coal-fired electricity generation by looking at the spread indicators on selected wholesale markets. All in all, gas emerged as the more competitive fuel in the reference quarter thanks to its low prices and also due to continually high CO2 prices.

In the case of UK, rapidly decreasing spot gas prices more than compensated for a fall in baseload and peakload contracts, which pushed the clean-spark spread to elevated levels above 12 €/MWh, last seen in 2016. Clean dark spreads in the UK, on the other hand, moved deep into the negative territory on the back of high CO2 prices and falling gas prices.

Monthly average German power prices were 10 – 15 €/MWh lower when compared to the UK reference and were going down even more sharply than in the UK, while at the same time the continental gas benchmarks were moving in line with the UK references. This resulted in gas-fired generation remaining close to the breakeven price throughout the reference period, implying that the actual result by a power generation asset depended on the specific efficiency rate.

More interestingly for the German power mix, a comparison with clean dark spreads, which moved deep into the negative territory over the reference quarter, reveals a fundamental shift in market dynamics, in which for the first time in many years gas-fired generation displayed consistently better competitiveness compared to coal in Germany. This was the case for both higher- and mid-efficiency gas plants, which moved in front of their coal-fired peers on the merit order curve, as evidenced by the increased share of gas at the expense of coal in Q1 2019 in Figure 9. In absolute terms, gas-fired generation reached 148 TWh in the reference quarter across the EU, the highest figure for a Q1 yet. The turnaround, which in some ways started at the end of last year, was driven by a combination of low gas prices and relatively high CO2 prices, which hovered above 20€/t during most of the reference quarter and which put the much more CO2-intensive coal-fired generation at a big disadvantage to gas. The trend is visible also along the forward curve, with German year-ahead clean spark spreads reaching their highest since 2012 at the end of Q1 2019, moving ahead of older coal units and closing in even on the more efficient ones.

This means that the outlook for coal-to-gas switching is further improving and that the continent could move closer to the market conditions in the UK, where carbon price floor imposed first in 2013 significantly reduced the competitiveness of coal in power generation. Around 11 GW² of mid-efficiency hard coal plants in Germany could be displaced by gas during this summer. However, further coal-to-gas switching could be limited by lower

² An estimate by Platts.
power demand in summer months or high renewable output. Conversely, increased switching to gas will limit the potential for further CO2 price gains.

Figure 11 – Evolution of clean spark spreads in the UK and Germany, and electricity generation from natural gas in the EU

Source: S&P Global Platts and ENTSO-E

Figure 12 – Evolution of clean dark spreads in the UK and Germany, and electricity generation from coal in the EU

Source: S&P Global Platts and ENTSO-E

- Figure 13 shows the monthly frequency of occurrence of negative hourly wholesale electricity prices in some markets, where this phenomenon is the most frequent in the EU. 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 baseload power generation (e.g.: nuclear). In such cases, conventional power plants begin to offer their output for a negative price in an effort to avoid switching the unit off and having to go through a maintenance intensive operation to restart the facility when they are required again.

- As can be followed from the chart, the number of hours with negative wholesale prices in Q1 2019 was relatively high compared to previous quarters. Most of hourly negative prices occurred in March due to strong wind generation and mild weather conditions and was concentrated mainly around the German and neighbouring markets. The increased incidence of negative prices in the Irish zone occurred as a result of the integration of the markets of Ireland and Northern Ireland which took effect in Q4 2018 and which introduced real time price signalling that more accurately reflects flexibilities in the power market during high wind periods.
Figure 13 – Number of negative hourly wholesale prices on some trading platforms

Source: Platts, European wholesale electricity markets

- Figure 14 shows that in the first quarter of 2019 the gap between wholesale electricity prices in Europe and the US narrowed as a result of a sharp drop of the EU benchmark and a slight increase of its US peer. On average, US quarterly wholesale electricity prices were 46% lower than the EU benchmark index.

- Wholesale electricity prices in Australia surged to 80 €/MWh at the beginning of 2019 (which is the summer season in the Southern Hemisphere) due to extreme heat waves and dropped to around 60 €/MWh in the rest of the quarter. Japanese wholesale prices followed the downward trajectory, in line with their European peers thanks to decreasing gas prices and mild weather conditions, falling from 80 €/MWh in January 2019 to 60 €/MWh at the end of the quarter, and landing at similar levels as prices in Australia.

Figure 14 – Comparison of the monthly average wholesale electricity prices in Europe, US, Japan and Australia

Source: European Power Benchmark, JPEX (Japan), AEMO (Australia) and the average of PJM West and ERCOT regional wholesale markets in the United States

2.2 Traded volumes and cross border flows

- Figure 15 shows the monthly evolution of electricity traded volumes, including exchange-executed trade and over the counter (OTC) market trade on the most liquid European hubs. Similarly to the last few years, in Q1 2019 the highest trade volumes could be observed in the German market, followed by the Nordic markets, and the UK, with Italy and France jostling for the fourth place.

- Traded volume of electricity shows a high degree of seasonality, following the higher consumption during winter periods. In the first quarter of 2019, similarly to earlier years, the total quarterly traded volume of electricity showed a slight decrease to 2,978 TWh compared to the previous quarter in which the total volume was 3,165 TWh.
Figure 15 – Monthly traded volume of electricity on the most liquid European markets

![Monthly traded volume of electricity on the most liquid European markets](image)

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

- **Figure 16** shows the comparison of volumes in different market segments of electricity trading on the most liquid electricity trading platforms in the EU. In Q1 2019 in year-on-year comparison, the total traded volume of electricity increased in Germany (by 5%), United Kingdom (by 9%), Spain (by 9%) and Belgium (by 5%). In contrast, traded volume of electricity decreased in France (by 30%), Nordic markets (by 22%), Italy (by 3%) and in Central and Eastern Europe (by 11%).

- In different segments of the electricity trade the movements in traded volumes were mixed. In Q1 2019 the overall traded volume decreased by 3% in year-on-year comparison, driven by the fall in the over-the-counter (OTC) trade by 9%, while the volume of exchange-executed contracts increased by 14%. Consequently, the share of exchange-executed trade increased from 29% to 33% between the first quarter of 2018 and 2019.

Figure 16 – Comparison of electricity traded volumes in some important day-ahead, forward and OTC markets, first quarter of 2019

![Comparison of electricity traded volumes in some important day-ahead, forward and OTC markets, first quarter of 2019](image)

Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations
Market liquidity can be measured by the churn rate which is calculated as the ratio of the total volume of power trade (including exchange executed and OTC markets on the spot and the curve) and electricity consumption in a given time period. In other words, the churn rate measures how many times a unit of electricity is traded before it is finally consumed.

Figure 17 shows the evolution of the quarterly regional churn rates from early 2016 to the reference period. Germany remained by far the most liquid market in Europe, with churn rates 3 to 8 times higher than in other regional markets in Q1 2019. Compared to the same period of the previous year, market liquidity slightly increased in Germany (as the churn rate grew from 12.9 to 13.5). Compared to the previous quarter, churn rates decreased in all the observed markets in Q1 2019 as lower trading activity met with increased consumption.

Figure 17 – Quarterly churn rates on selected European wholesale electricity markets

Source: Trayport, London Energy Brokers Association (LEBA), ENTSO-E and DG ENER computations

Figure 18 reports on the regional cross-border flows of electricity in Q1 2019. The CWE region cemented its position as the power core of the continent, having plentiful generation capacities, the most competitive prices and a good position to supply all the other regions. Net export flows grew month by month, adding up to 22.5 TWh for the whole reference quarter (+14% compared to Q1 2018). Strong renewable generation in the region and recovering performance of the French nuclear fleet contributed to this result.

Italy remained by far the largest importer of electricity in Q1 2019, purchasing more than 10.5 TWh, mainly from Switzerland and France and, to a lesser extent, Slovenia. A minor fraction of this volume was shipped to Malta. Compared to Q1 2018, however, the net import volume decreased by 22% on the back of mild weather conditions and good domestic supply. Similar factors reduced the net import of the CEE region by 55% year-on-year to 2.2 TWh in the reference quarter.

The Nordic, Iberian and SEE regions, on the other hand, experienced increased inflows compared to a year earlier, mainly owing to lower hydro generation caused by a dry summer last year. The Nordic region even lost its traditional position of a net exporter due to low hydro reservoir levels. The South-Eastern region emerged as a net exporter only towards the end of the quarter, as its hydro production gradually recovered. The position of the British Isles as a net importer remained broadly unchanged, with volumes in Q1 2019 similar to Q1 2018.
Figure 18 – EU cross border monthly physical flows by region

Source: ENTSO-E, TSOs

- Figure 19 compares net cross border flows to regional power generation. Positive values indicate a net exporter. In Q1 2019 the Baltic region imported an amount equivalent to roughly 40% of the domestically generated electricity. While it was less than in Q4 2018, such figures are more common during the summer season. High shares of imports indicate difficulties facing domestic generation assets or more favourable price conditions in the neighbouring areas. Relatively high CO2 prices, which negatively affect the competitiveness of fossil-based power plants in the region, play an increasing role in the developments there.

- In terms of relative shares, Italy retained the position of the second biggest importer relative to its output. For other regions the net cross border position was less than 10% compared to domestic production. It is noteworthy that outflows form the CWE region, which is a significant exporter in absolute terms, are not that big in relation to its total production and that this ratio never rose above 8% so far.

Figure 19 – The ratio of the net electricity exporter position and the domestic generation in the regions

Key to country distribution in regions: CWE (AT, DE, BE, NL, FR), CEE (CZ, HU, PL, SK, SI, HR), Nordic (DK, SE, FI), Baltic (LT, LV, EE), Iberia (ES, PT), SEE (BG, GR, RO), British Isles (UK, IE), Apennine Peninsula (IT, MT)

Source: ENTSO-E, TSOs, Eurostat, DG ENER calculations
3 Regional wholesale markets

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

- In the first quarter of 2019 the monthly average wholesale baseload electricity price in the CWE region declined from 54 €/MWh in January to 33 €/MWh in March (Figure 20). Likewise, the monthly average wholesale peak-load price in the CWE region declined from 62 €/MWh in January to 35 €/MWh in March 2019. The decline was driven by mild weather, with temperatures well below the long-term average in February and March 2019. In France, as a very weather sensitive market due to electric heating, electricity consumption decreased by 4% in the first quarter of 2019 compared to the same quarter of the previous year. Therefore, strikes at some coal-fired plants and ongoing maintenance at a few nuclear-power units did not have a measurable effect on prices.

- Due to increased capacity and good weather conditions, the importance of wind electricity generation increased in the CWE region in the first quarter of 2019. Wind output in Austria peaked in the first week of 2019 with an average of 32% in the total generation, remaining at increased levels throughout the quarter.

- In Germany, which is the EU leader boasting 60 GW of installed wind capacity (on- and offshore), wind-powered generation was particularly high in the first quarter of 2019, with an average share of 29% in the total generation. On a daily average, the share of wind electricity in the total generation even exceeded 50% on thirteen days in the reference quarter. Wind is on track to become Germany’s biggest single source of electricity this year, with 43 TWh generated in Q1 2019 versus 28 TWh for lignite.

Figure 20 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in Central Western Europe

Source: Platts, EPEX

- **Figure 21** shows the average regional day-ahead baseload prices for the first quarter of 2019. The quarter was subject to a few price spikes on a daily frequency. The average daily baseload electricity price in Germany ranged from -4.3 €/MWh to 85.3 €/MWh in the first quarter of 2019. Some of the price volatility can be linked to the variable output of wind electricity generation. On 1st and 13th of January and 9th of February wind electricity generation reached a peak share of more than 57% of the total generation, pushing daily prices down to extreme lows. In contrast, on 24th of January wind electricity generation reached a quarterly low with only 3% in the total generation, resulting in a spike in daily price peaking at 85 €/MWh.

- The price difference between the German and Austrian day-ahead market decreased strongly in the first quarter of 2019. The formerly jointed price zones are split since October 2018 in order to facilitate the operation of the TSOs. Whereas the daily average Austrian day-ahead baseload price was 7.52 €/MWh higher compared German baseload prices in the fourth quarter of 2018, the price differential decreased to a daily average of 4.12 €/MWh in the first quarter of 2019. As in the previous quarter, the price differential in the first quarter of 2019 between the observed markets is strongly influenced by extreme price falls in the German market as visible in **Figure 21**. Hence, the medium price differential between the Austrian and German day-ahead market at 1.56 €/MWh was considerably lower than the average price differential between these markets in the first quarter of 2019.
Figure 21 – Daily average wholesale power prices in the CWE region in Q1 2019

- Nuclear electricity generation in France gradually returned to normal performance levels in the first quarter of 2019 and was better compared to the previous quarter, as shown in Figure 22. Despite ongoing inspections at some units, small restrictions in capacity put no pressure on the French market due to mild weather conditions.

- In Belgium, nuclear-powered generation increased notably in the first quarter of 2019 compared to the previous quarter after the Tihange 3 reactor returned to operation. In combination with the end of winter, net electricity imports in Belgium decreased significantly compared to the previous quarter as well as the previous year.

Figure 22 – The weekly amount of generated nuclear electricity in France

Source: Platts
3.2 British Isles (UK, Ireland)

- Figure 23 informs about the monthly volumes and prices at the day-ahead markets in the United Kingdom and Ireland. After a high-price period in Q4 2018, the base- and peakload prices declined sharply during Q1 2019, on the back of mild temperatures in February and March as well as falling gas prices and good renewables performance. Average baseload prices went down by 28% during the quarter, while average peakload prices fell by 32% in the reference period.

Figure 23 – Monthly exchange traded volumes of day-ahead contracts and monthly average prices in the UK and Ireland

Source: Nordpool N2EX, SEMO

- Figure 24 shows that in Q1 2019 wholesale baseload electricity prices in the UK and Ireland responded to falling demand and followed the general trend of decreasing prices of gas, which is the fuel that tends to set marginal electricity generation cost in the country. Another factor supporting the supply side was the start of a new 1 GW UK-Belgium Nemo interconnector which increased the possibility of imports from the continent. The weakening of power prices continued despite two nuclear units’ delayed return into operation and a few unplanned maintenances at other units. Longer periods of negative system prices during weekends appeared in March, as large renewable output and increased import capacity met with lower-than-expected demand. Baseload prices in Ireland generally followed the UK contract, albeit with larger volatility influenced by fluctuations in wind availability. Increased levels of Irish wholesale prices at the beginning of the year can be attributed to unplanned outages at large conventional power plants.
Figure 24 – Daily average baseload electricity prices in the UK and Ireland

Source: Nordpool N2EX, SEMO

- **Figure 25** compares the weekly evolution of the electricity generation mix in the UK between the reference quarter and the quarter a year before. Due to elevated CO2 prices and competitive gas prices, coal-fired generation was almost completely priced out of the market towards the end of Q1 2019. Counting recently announced closures, only five coal-fired power plants should remain in service in the country as of 2020. That includes two units at Drax which are scheduled for conversion to gas pending government approval. With relatively stable nuclear output, gas-fired generation established itself as the main counterweight to balance out the fluctuations in wind availability.

- During the reference period the share of nuclear generation in the UK’s electricity mix, at 21%, remained approximately similar to the figure reported a year ago. The same can be said about the share of wind, which stood at 17% in Q1 2019. The biggest change happened within the fossil fuel segment, in which the share of coal plummeted from 11% to 5%, whereas gas increased its share from 45% to 52% year-on-year, cementing its position as the dominant source of supply.

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

- Low hydro reservoir, snow and precipitation levels in Northern Europe combined with high demand saw the Nord Pool average wholesale price in January rise to 55 €/MWh, the highest on record, with the peak occurring at the end of January. After that prices began to gradually decline on the back of more rainfall and warmer weather conditions, which pushed down heating-related electricity demand. Electricity has important role in heating in many Nordic countries. The deficit in reservoir levels gradually lessened. Baseload prices were pushed down fur-
ther in March thanks to strong wind generation in Sweden and Finland, finishing the quarter below 40 €/MWh. By the end of the quarter, the region’s hydro balance went back to the long-term average.

Figure 26 – Monthly electricity exchange traded volumes of and the average day-ahead wholesale prices in Northern Europe

- Figure 27 shows the weekly hydro electricity generation in Norway in Q1 2019 compared to previous years. The trend of a relatively low hydro electricity generation in Q4 2018 intensified during January 2019. By the fourth week of the year, hydro output dropped below the weekly generation of 2017 as a new low in the 7-year-range. This was influenced by a combination of higher demand in winter and overall low precipitation levels. Milder weather, increased precipitation, and higher wind electricity generation helped to decelerate this trend by the sixth week of the year. By the end of Q1 2019, the weekly hydro electricity generation in Norway recovered to an average level compared to the previous years.

Figure 27 – Weekly hydro electricity generation in Norway in 2019, compared to the range of 2013 to 2018

- Figure 28 shows that baseload prices across the Nordic countries remained well-aligned during most of Q1 2019, with the occasional exception of dips in Danish prices caused by strong wind generation there. Overall, cold temperatures and low hydro reservoir levels drove the prices up to record levels towards the end of January, after which the downward trend set in, supported by milder weather conditions and good wind availability.
During the whole reference quarter the Nordic region became a net electricity importer, which is unusual for this time of the year, as its wholesale electricity prices were generally higher there than in some countries in Central and Western Europe. Contributing to the net importer position of the observed region were imports from the Russian market to Finland and the Baltics, which rose significantly to 3.5 TWh (+50 % compared to Q1 2018 as shown in Figure 29) and which helped to keep the wholesale market in those countries well supplied. The elevated level of Russian imports, which began to increase materially in the second half of the last year, could be associated with the move of the Finnish grid operator to reduce tariffs on electricity imports from Russia from July 1, and also with a worsened market position of some Baltic fossil fuel-based generation capacities which have been losing competitiveness due to heightened CO2 prices. The bill for the electricity imports from Russia reached €186 million in the reference quarter (+139% year-on-year)\(^3\).

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\(^3\) According to Eurostat.
Figure 29 – Net monthly electricity flows to the Nordic region from the Russian market compared to the CO2 spot price

Source: Litgrid, Fingrid, S&P Global Platts

3.4 Apennine Peninsula (Italy, Malta)

- The Italian wholesale baseload and peakload electricity prices decreased sharply in the first quarter of 2019, in line with the other European wholesale markets (Figure 30). The baseload electricity price decreased from 68 €/MWh in January to 53 €/MWh in March 2019. Likewise, the peakload electricity price decreased from 73 €/MWh in January 2019 to 55 €/MWh in March 2019.

- On the demand side, daily average temperatures in Italy were lower in January 2019 compared to the long-term average resulting in an increase in prices compared to December 2018. With temperatures above the long-term average in February and March 2019, prices fell accordingly. On the supply side, decreasing natural gas prices supported the decrease in wholesale electricity prices.

Figure 30 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy

Source: GME (IPEX)

- Figure 31 shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. In the first quarter of 2019 the national average price moved closely along a downward trend starting at the end of January. The price peak in the last week of January relates to a cold snap in combination with a period of low wind electricity generation.
The Italian Power Exchange provides, in addition to the regional markets in Italy, also insights on foreign price zones such as Malta. The island is a net electricity importer from Italy and thereby daily prices from the Italian power exchange influence the Maltese wholesale electricity market. As visible in Figure 31, the price for the Maltese zone follows closely the lower range of regional Italian electricity prices. Price spikes such as the one on 12th of March indicate low electricity change between the price zones.

**Figure 31 – Daily average wholesale electricity prices in the Italian market, within the range of different area prices**

Source: GME (IPEX)

### 3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 32** reports on the monthly average wholesale baseload and peakload contracts in Spain and Portugal which fell from levels above 60 €/MWh in January to under 50 €/MWh in March 2019, as higher temperatures in the second part of the quarter combined with muted industrial demand and lower input prices weighed on the market. Spanish power demand from large industrial consumers recorded fourth consecutive annual decline in Q1 2019 on the back of weakening metals industry and stagnating auto manufacturing production. Compared to Q1 2018, the average baseload price rose by 15% in the reference quarter.
Figure 32 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula

Source: Platts, OMEL

- **Figure 33** displays the evolution of the weekly electricity generation mix in Spain during the first quarter of 2019, as well as during the same period of the previous year. The combined share of renewable energy sources (hydro, wind, solar and biomass) reached roughly 40% on average throughout the period. This was 4 percentage points lower than the share of renewables during the first quarter of 2018, mainly due to weaker wind and hydro output. The share of wind-powered generation declined from 26% to 23%, while the share of solar increased from 3% to 5% year-on-year.

- The combined share of coal and gas in the mix went up from 28% in Q1 2018 to 32% during Q1 2019. However, this was only thanks to a significant increase in the gas sector which increased its share from 17% to 23% year-on-year, whereas coal suffered a fall from 12% to 10% year-on-year. It is clearly visible that the coal-to-gas switching trend, present in Germany, Netherlands and the UK, influenced also the Spanish power mix. The competitiveness of gas in Spain was also helped by the removal of a tax on gas used by CCGT and cogeneration units last October.

- The share of nuclear energy in Spain’s energy mix, at 24%, was 3 percentage points higher during the reference period than in Q1 2018, as unplanned outages at the beginning of this year were compensated for by good performance during the rest of the quarter.

Figure 33 – Weekly evolution of the electricity generation mix in Spain in Q1 of 2018 and 2019

Source: ENTSO-E

- **Figure 34** shows that Spanish day-ahead prices started the year at a 4 €/MWh premium to French prices, much lower than at same time last year, thanks to good wind output which countered unplanned nuclear outages. As wind-power generation ramped higher in Spain in the next weeks, the premium reversed into a discount, with power flows to France reaching a peak at the beginning of February. Then came another reversal when French prices started falling at a greater pace than their Spanish peers due to a much improved performance of the...
French nuclear fleet. As a result, the Spanish premium climbed above 20 €/MWh in the middle of March, after which it settled around 15 €/MWh. Overall, total net French exports to Spain in Q1 2019 reached 546 TWh (up 61% compared to Q1 2018).

Figure 34 – Weekly electricity flows between France and Spain and price differentials between the two markets

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

- Figure 35 shows that average monthly prices for baseload and peakload power in Central Eastern Europe have followed the same downward trajectory as other regions in the first quarter of 2019, in a context of falling trading activity.

- Monthly baseload prices fell from 65 €/MWh on average in January to 38 €/MWh in March, in line with the developments in the Central Western region. At the beginning of the year, prices were driven up by cold weather, but the demand pressure eased afterwards as temperatures in February and March reached above-average levels, wind availability improved and imports of cheaper output from the CWE region and Nord pool covered demand during peak hours. That is why peakload prices registered a steeper fall from 75 to 42 €/MWh throughout the reference quarter.

- When compared to last Q1, however, the average baseload price in the reference quarter went up by 30% to 50 €/MWh.

- The region remained a net importer of electricity in the reference quarter, but to a much lower extent than in Q1 2018, with net inflows reaching 2.2 TWh in Q1 2019, compared to 4.6 TWh in Q1 2018, as a warmer end of the winter curbed demand.
Figure 35 – 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 36 reports that daily average wholesale prices in the CEE region registered higher volatility and dissonance in January, mainly as a result of changing weather conditions in individual markets, fluctuating wind output in Poland and Germany and changes in import capacities. Prices started to climb down in February due to warmer conditions, better wind availability and sufficient import capacities which were able to compensate for unplanned nuclear generation outages in Hungary and Slovakia.

Figure 36 – Daily average wholesale power prices in the CEE region

Source: Regional power exchanges, Central and Eastern Europe (CEE)
CEE: PL, CZ, SK, HU, RO, SI
3.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- **Figure 37** shows that after three quarters of constant rises, wholesale baseload electricity prices in the SEE region peaked at 75 €/MWh in January as low hydro reservoirs, depleted after a dry summer, limited supply availability. The reversal came in February thanks to milder weather conditions and a surge in hydropower output which benefited from stronger Danube flows. The downward trend continued for the rest of the quarter as plentiful rainfall and snowmelt supported run-of-river production. The baseload contract in the whole Q1 2019 reached 67 €/MWh on average, up 35 % compared to Q1 2018.

- Whereas at the beginning of the year the average monthly peakload price stayed above the average baseload price in the SEE region, that changed in February and resulted in an average 1-2 €/MWh premium of baseload over peakload. This price behaviour, with positive price differences between the base- and peakload price, in the SEE region is mainly driven by the Greek electricity wholesale price, which decoupled from the rest of the region in February and March, as shown in **Figure 38**, and stayed 15-20 €/MWh higher than in neighbouring markets.

- Overall, the average Bulgarian baseload electricity price in Q1 2019 increased by 40% year-on-year to 47 €/MWh. A similar 39% rise occurred in Greece where average baseload contract reached 70 €/MWh. The average Serbian baseload price in the reference quarter jumped by 46% year-on-year to 55 €/MWh.

- In the SEE region, Bulgaria is a net exporter of electricity to the Serbian and Greek market. In Q1 of 2019, a volume of 0.5 TWh was transferred from Bulgaria to Greece and 0.5 TWh from Bulgaria to Serbia. These values are similar to those in Q1 2018.

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**Figure 37** – Monthly traded volumes and prices in South-Eastern Europe (SEE)

Source: IBEX, LAGIE, OPCOM, SEEPEX

**Figure 38** – Comparison of daily average day-ahead prices in Bulgaria, Croatia, Greece and Serbia

Source: IBEX, LAGIE, SEEPEX, CROPEX
4 Retail markets in the EU and outside Europe

4.1 Retail electricity prices in the EU

- Figures 39 and 40 display estimated retail prices in March 2019 in the 28 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).

- Median industrial consumers (band IB) paid the highest prices in Italy (18.2 c€/kWh) and Germany (17.8 c€/kWh), followed by Ireland, Belgium and the UK (15.7 to 16.3 c€/kWh), apart from the non-interconnected island system of Cyprus. The lowest prices were assessed to be in Sweden (8.8 c€/kWh) and Finland (9.3 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. Industrial consumers with large annual consumption (IF), including most energy intensive users, paid the highest prices in the United Kingdom (11.7 c€/kWh) followed by Slovakia and Ireland. Luxembourg (3.7 c€/kWh) had the lowest prices, followed by Sweden and France. The ratio of the highest to lowest price for large industrial consumers was around 3:1 for this consumer type.

- In March 2019, Belgium (31.2 c€/kWh) was assessed as having the highest median household price for electricity consumers, overtaking both Germany (30.8 c€/kWh) and Denmark (at 30.1 c€/kWh). The lowest price was calculated for Bulgaria (10.1 c€/kWh). Household electricity prices are even more impacted by taxes and levies than their industrial counterparts. The variety and level of taxes and levies differs significantly from country to country, therefore the ratio of the largest to smallest price is higher for this consumer class, exceeding 3:1.

Figure 39 – Industrial electricity prices, March 2019 – without VAT and recoverable taxes

Source: Eurostat, DG ENE
Figures 40 and 41 display the convergence of retail prices across the EU over time, by depicting their standard deviation. Prices for all three levels of industrial consumption became more convergent between January and February 2019, after which the dispersion stabilized for large- and medium-sized industrial consumers of electricity and grew higher for small consumers. The energy component, which was largely responsible for dispersion for all three levels of consumption, accounts for less than 40% of prices paid by industrial consumers with small and medium volume consumption.

The evolution of household price convergence was less volatile as such prices are more impacted by regulated elements (network charges, taxes and levies) which make up on average 40% of the final bill. After becoming more and more divergent throughout 2018, household price prices in all the consumption bands started to converge again in Q1 2019, albeit at a slow pace. In the case of small and medium-sized households the divergence of prices still hovered at historically high levels at the end of the reference quarter.
The following maps (Figures 43 and 44) display estimated electricity prices paid by households and industrial customers in the EU, with medium level of annual electricity consumption in the last month of Q1 2019. In the case of household prices, Belgium replaced Denmark at the top of the list, while Bulgaria retained its position as the cheapest country compared to December 2018. The average price in the EU stayed without significant changes compared to the situation in Q4 2018 and rose by 2.4% compared to Q1 2018. In the case of industrial prices, Finland reported the most competitive figure in Q1 2019, unchanged from the previous quarter. The average industrial electricity price in the EU decreased by 1.1% compared to Q4 2018, but rose by 2% compared to Q1 2018.

The comparison of household and industrial consumers shows that the latter ones display a significantly lower retail price dispersion across the EU, which could be traced to increased attention to cost competitiveness paid by the industry.

Source: Eurostat, DG ENER
Figure 43– Household Electricity Prices, first quarter of 2019

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices.
Figure 44 – Industrial Electricity Prices, first quarter of 2019

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices.
The following graph (Figure 45) shows retail electricity prices recorded in European capital cities. In March 2019 the highest prices were observed in Berlin and Copenhagen (31.3 and 31 c€/kWh, respectively), much in line with the Eurostat data analysed above, apart from the position of Belgium. While on national average Belgium was the most expensive country, Brussels was the sixth most expensive capital with prices 25% lower than the rest of the country. The lowest prices were recorded in Sofia and Budapest (11.1 c€/kWh and 11.9 c€/kWh respectively). Compared to the same month of the previous year, the largest price increases are observed in London and Amsterdam (both +21%), followed by Brussels (+19%) and Helsinki (+17%). In all four cities the energy component was the biggest contributor to rising prices, while in the case of the capitals in the UK and the Netherlands growing energy taxes played their part too. Eight EU capitals reported prices lower than in the same month of the previous year, with Zagreb, Bucharest and Warsaw posting the largest drops. The price fall in the Croatian capital was caused almost exclusively by a lower VAT rate, whereas in the Romanian capital the decreasing energy component was the driving force.

Figure 45– The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh March 2019, and changes in % in household electricity prices compared to March 2018

The energy component increased in all but five EU capitals from March 2018 to March 2019, with the highest rises registered in Belgium, Cyprus, the UK and Portugal, as shown in Figure 46. Network charges remained broadly stable across the EU, with the exception of Portugal where a significant decrease drove the entire electricity bill lower in spite of a more expensive energy component. Another fall in network charges occurred in Poland where a price freeze was announced at the beginning of this year. Measurable increases in network charges were reported from Brussels, Helsinki, Ireland, Lithuania and London. Energy taxes decreased materially in Denmark and Ireland, while going up in the UK, the Netherlands and Luxembourg.
Figure 46 – Year-to-year change in electricity prices by cost components in the European capital cities comparing March 2019 with March 2018

Source: Vaasaett

4.2 International comparison of retail electricity prices

- The following graph (Figure 47) displays industrial retail prices paid by consumers in Europe and in its major trading partners. Prices include VAT and other recoverable taxes for the purpose of comparability.

- Prices in the EU remained relatively high, second only to prices in Brazil. Differences between wholesale electricity prices in the EU and the US are mirrored by differences between EU and US retail prices, with EU prices rising continually since 2017 and US prices on a mostly decreasing trajectory during the same period. The US and Brazil were the only countries from the roster where retail prices dropped in Q1 2019 compared to the previous quarter. The rest registered increases, with South Korea (+7%) leading the list, followed by Indonesia (+5%), China and the EU (both +3%).

- Over the last three years, retail electricity prices for industry rose most in Brazil (+21%) and the EU (+8%, +5% accounting for inflation). China, on the other hand, registered a 14% decrease. Price levels in Indonesia and South Korea remained broadly unchanged.

Figure 47 – Retail electricity prices paid by industrial customers in the EU and its main trading partners

Source: Eurostat, IEA, CEIC, DG ENER computations
5 Glossary

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

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

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

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

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

**Dark spreads** are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 35% efficiency. Dark spreads are given in this publication for UK and Germany, with the coal and power reference price as reported by Platts.

**European Power Benchmark (EPB7)** is a replacement of the former Platt’s PEP index discontinued at the end of 2016, computed as weighted average of seven major European markets’ (Belgium, France, Germany, Netherlands, Spain, Switzerland, United Kingdom) 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 50% efficiency. Spark spreads are given for UK and Germany in this publication, with the gas and power reference price as reported by Platts.

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.