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HIGHLIGHTS OF THE REPORT

- Coal-to-gas switching shifted into high gear across the EU in Q3 2019 as gas prices remained close to multiyear lows and rising CO2 prices severely undermined the profitability of coal-fired power plants. Even the relatively cheaper lignite generation faced strong headwinds due to its high carbon intensity.

- EU-wide electricity generation from solid fuels plunged by 35% year-on-year in the reference quarter. That in absolute terms meant 50 TWh less electricity produced by burning coal and lignite, an equivalent of the annual consumption of Portugal. This also translated into approximately €2.5 billion of lost revenues from the operation of coal and lignite assets in the reference quarter. Gas-fired power production managed to replace a great part of coal and lignite in the mix, increasing by 20% (or 28 TWh) year-on-year, but was limited in its expansion by rising renewable generation (+12 TWh), mainly in the wind sector, and by falling consumption (-7 TWh). Onshore wind farms alone provided more electricity to the grid than lignite-based power plants in Q3 2019. Meanwhile, solar PV output overtook coal generation volumes.

- As a result of its significantly reduced use, thermal coal imports from outside of the EU in Q3 2019 fell by 39% year-on-year to 18.3 Mt, beating the record low amount from the previous quarter and establishing a new all-time minimum. Several early retirements of coal units were announced or brought forward in the reference quarter. Greece and Hungary unveiled plans to phase out coal and lignite in their mix by 2028 and 2030 respectively.

- The share of renewable energy in the EU power mix reached 33% in the reference quarter, the highest for a third quarter yet and higher than the corresponding shares in India (27%), China (26%) and the United States (15%). Total combined output of solar, wind and biomass generation in the EU in the reference quarter increased by 10% year-on-year to 157 TWh. Thanks to expanding renewable generation and intensified coal-to-gas switching, the EU’s electricity sector, which is one the largest emitters of greenhouse gases on the continent, was on track to decrease its carbon footprint by more than 10% this year.

- Wholesale electricity prices increased in more than two thirds of individual EU markets in Q3 2019 on the back of higher carbon costs and weak hydro generation, with the biggest rises concentrated in the Balkans. Several large markets with relatively less carbon-intensive generation bases recorded stable (Italy, France) or decreasing (Spain, the UK) baseload prices. The pan-EU average price rose to 47.0 €/MWh, up 9% compared to the previous quarter.

- The average price of emission allowances rose by 6% to 27 €/t in the third quarter. It almost touched 30 €/t at the end of July, a level last seen in 2006. Carbon prices were influenced by electricity market drivers - such as rising cooling demand during summer heatwaves or temperature-related restrictions on nuclear availability - and expectations of a limited supply of allowances during August when government auctioning activity usually slows down. Events surrounding the Brexit issue continued to be a factor as well.

- A new 700 MW interconnector linking the Netherlands and Denmark for the first time was put into operation in September. The 325km subsea high-voltage direct current cable will enable the Dutch market to import more renewable electricity from the Danish grid and also help ease some of the constraints the Nordic networks have to cope with during periods of strong wind generation.

- In August, the British electrical system experienced a power outage that affected 1.1 million customers who were disconnected for around 50 minutes. This was the largest power cut in over a decade in the UK. Apart from customers without power, other effects included major disruption to parts of the rail network and other critical facilities such as hospitals or airports. A wide discussion about the costs and benefits of ensuring security of supply took place in the aftermath.

- In the retail market, the largest year-on-year increases in the household category in September were assessed in the Netherlands and the UK (both +16%), Czechia (+15%) and Lithuania (+14%). The biggest year-on-year falls were estimated for Spain (-19%), Denmark (-13%) and Cyprus (-11%).
EXECUTIVE SUMMARY

- EU-wide electricity consumption declined by approximately 1% year-on-year in Q3 2019, driven by decreases in larger Member States. Of the major economies, power consumption increased in Spain (+3.2%) and Italy (0.6%), while falls were registered in Germany (-3.1%), Poland (-2.1%), France (-1.7%), the UK (-1.1%) and the Netherlands (-0.5%). The measurable fall in Polish consumption is noteworthy as it took place against the backdrop of 3.9% annual GDP growth, one of the highest among the Member States.

- Spot gas prices, represented by the TTF day-ahead contract, remained close to multiyear lows and on average reached 10.2 €/MWh in Q3 2019 (down 21% compared to Q2 2019), amid sufficient pipeline deliveries, plentiful LNG supply and high storage levels. Spot coal prices, represented by the CIF ARA contract, moved closer to the levels on the forward curve, increasing by 5% compared to the previous quarter to 51.1 €/MWh.

- The carbon market reached new highs in July, but gave up some of its gains during the rest of the quarter. At 27 €/t, the average price of one emission allowance in Q3 2019 was nevertheless 6% higher than in the previous quarter and 43% higher compared to the same quarter a year ago. This was a major driver of intensified coal-to-gas switching across Members States.

- In Q3 2019, the estimated EU import bill for thermal coal amounted to €1.5 billion, 45% lower compared to Q3 2018. This exceeded the year-on-year decline in imported volumes due to lower commodity prices. The significant fall in coal imports reflected adverse conditions for coal-fired generation in the quarter. The largest share of extra-EU thermal coal imports (65%) came from Russia.

- Rising CO2 prices continued to significantly influence the structure of thermal generation as less CO2-intensive gas gained prominence, reaching a 25% share in the overall EU power mix in Q3 2019 (compared to 20% in Q3 2018), at the expense of hard coal and lignite, which saw its combined share reduced to 13% (from 20% in Q3 2018). Increased carbon costs and growing renewable penetration undermined the economics of both coal and lignite units. As a result (and also thanks to some plant closures), lignite-based generation in Q3 2019 fell by 24% year-on-year (or 17 TWh), while hard coal generation plunged by 46% year-on-year (or 33 TWh).

- The combined share of hydro, biomass, wind, solar and geothermal sources in the EU generation mix reached 33% in Q3 2019 (up from 31% in Q3 2018). The main driver behind the increasing importance of renewable power in the reference quarter was wind generation which in its onshore segment expanded by 14% year-on-year (or 7.9 TWh) and in the offshore sector recorded a 40% year-on-year jump in generation (or 4.3 TWh). With 11.2% of the electricity mix, wind overtook hydro as the largest contributor to renewable output. The share of solar reached 6.6% in Q3 2019.

- A milestone was reached during an auction in Portugal in August which awarded 1.15 GW of solar PV capacity at an average price between 20 and 21 €/MWh. The auction saw one successful bid of just 14.8 €/MWh for a 150 MW lot, which represented a 67% discount to the reference tariff of 45 €/MWh and a world record, beating the previous low of around 15.8 €/MWh set this summer in Brazil.

- The European Power Benchmark of seven major markets averaged 39.1 €/MWh in the reference quarter, down 2% compared to the previous quarter. Matched against the value from Q3 2018, the wholesale benchmark fell by 12%. The lowest prices could be found in the Norwegian market (35.4 €/MWh) which benefited from cheap hydro generation and increased wind output. Average wholesale prices in Greece, Poland and Romania, in contrast, approached or exceeded 60 €/MWh. The differences could be partly explained by interconnection insufficiencies or outages, partly by the effect of rapidly growing and unevenly distributed renewable output and also by the significantly strengthened CO2 price which impacts individual markets unevenly, depending on the local generation mix. This trend, coupled with several critical grid situations which occurred in the reference quarter, points to the need for increased investment in strengthening network resilience and expanding cross-border capacities.

- Average retail electricity prices for households in the EU stayed without significant changes in the reference quarter compared to the situation in Q2 2019 and rose by 2% compared to the last month of Q3 2018. In the case of mid-sized industrial consumers, Denmark was assessed to have the most competitive prices in Q3 2019, moving ahead of Sweden.
1 Electricity market fundamentals

1.1 Demand side factors

- **Figure 1** shows that the pace of economic growth in the European Union held steady in Q3 2019 compared to the previous quarter. According to an estimate published by Eurostat, seasonally adjusted GDP in the EU-28 expanded by 1.4% year-on-year between July and September 2019, which compares to 1.9% achieved in Q3 2018.

- According to the approximated data of Member States’ statistical services, regulatory authorities and TSOs, EU-wide consumption of electricity fell by approximately 1% year-on-year in Q3 2019, driven by decreases in larger Member States. Of the major economies, power consumption increased in Spain (+3.2%) and Italy (0.6%), while falls were registered in Germany (-3.1%), Poland (-2.1%), France (-1.7%), the UK (-1.1%) and the Netherlands (-0.5%). The measurable fall in Polish consumption is noteworthy as it took place against the backdrop of 3.9% annual GDP growth, one of the highest among the Member States. General stagnation of industrial activity was dragging down the consumption levels in the EU in Q3 2019.

**Figure 1 – EU 28 GDP annual change (%)**

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Source: Eurostat
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- **Figure 2** illustrates the monthly deviation of actual Cooling Degree Days (CDDs) from the long-term average in Q3 2019. EU-wide, the quarter had 42 CDDs above average (which translates to 0.5 °C higher than usual per day), mainly due to increased temperatures in July and August. In Italy, Hungary, Bulgaria and Croatia, daily temperatures in these two months exceeded the average by more than 1 °C, igniting increases in demand for cooling. France, Malta and Romania also experienced relatively hot summers, resulting in power demand spikes during heatwaves. Temperatures in September were generally in line with long-term averages on both the cooling and heating side. Cyprus, Malta and Portugal were the exceptions in this regards, recording a relatively warmer end of the summer season.

**Figure 2 – Deviation of actual heating degree days and cooling degree days from the long-term average in July-September 2019**

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Source: JRC.
The colder the weather, the higher the number of HDDs. The warmer the weather, the higher the number of CDDs.
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1.2 Supply side factors

- **Figure 3** reports on the developments in European coal and gas prices in Q3 2019. Spot prices of either commodity followed different paths, with gas contracts hovering close to 10-year lows for most of the reference quarter and their coal peers going through several ups and downs. Meanwhile, year-ahead prices moved more or less in tandem and remained in their contango position vis-à-vis the spot market.

- Spot gas prices (represented by the TTF contract) experienced a small short-lived rally at the beginning of the reference period, driven by Norwegian supply concerns and speculative bidding. Prices then returned close to the 10 €/MWh mark and didn’t react even during a wave of sweltering temperatures in the second half of July, which pushed EU-wide gas burn in electricity generation to record highs. The stable environment continued until the beginning of September when, despite Russian production turndows and maintenance works on Norwegian facilities, spot contracts started falling further on the back of mild temperatures and high wind availability, reaching a new record low of 7.5 €/MWh in the trough. A similar drop occurred at the end of the quarter. The market remained well supplied during the entire reference period thanks to, among other factors, plentiful LNG deliveries and record high storage levels. Overall, the average quarterly TTF spot price reached 10.2 €/MWh in Q3 2019 (down 21% compared to Q2 2019 and down 59% compared to Q3 2018).¹

- Thermal coal spot coal prices, represented by the CIF ARA contract, started the reference quarter on an upward trajectory, even though the momentum was driven more by speculative interest rather than fundamentals which still pointed to an oversupplied market. The trend peaked at the height of the heatwave in the second half of July, as some market participants hoped that the additional cooling demand could lead to more coal burn. In August, prices were continually sliding amid high stocks at major terminals, low demand and milder temperatures. Another turning point came in September and the new upward trend received a boost in the aftermath of the attacks on Saudi oil infrastructure in the middle of the month when increased international tensions temporarily pushed energy prices higher. Despite some easing in the next couple of days, spot coal prices finished the quarter measurably higher compared to the end of Q2 2019 and, unlike in the gas market, moved closer to the levels on the forward curve. All in all, the average quarterly CIF ARA spot price reached 51.1 €/MWh in Q3 2019 (up 5% compared to Q2 2019, but down 40% compared to Q3 2018).

- At 17.9 €/MWh, year-ahead gas prices in Q3 2019 were trading on average 6% lower than in the previous quarter, but remained considerably higher than their spot peers, clouding the prospects for stronger coal-to-gas switching in 2020. Meanwhile, year-ahead CIF ARA contracts closely followed gas on the forward curve, keeping clean dark spreads for the next year favourably positioned vis-à-vis their spark competitors.

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

The emission allowance market, shown in Figure 4, reached new highs in Q3 2019, almost touching the 30 €/t mark in July. But from then on CO2 prices followed a downward trajectory and finished the quarter below 25 €/t.

Prices began to climb in the second week of July amidst indications that allowances not demanded for coal plants subject to negotiated closures in Germany might be cancelled by the government in order to neutralize the effects of early retirements on the CO2 market. Carbon prices were also supported by increased power prices stemming from low wind generation forecasts and high temperatures restricting nuclear generation and pushing up cooling demand. The bullish sentiment was additionally driven by expectations of a limited supply of allowances entering the market in August when government auctioning activity usually slows down considerably. The rising trend continued until July 24 when, at the height of the heatwave, prices on the ICE Futures Europe exchange reached a 13-year intraday high of 29.95 €/t. However the psychologically significant threshold of 30€/t was not breached and, as temperatures returned to seasonally normal levels, CO2 prices retreated with them.

The downward trend continued in August despite the auctioned volumes in that month falling sharply to less than 30 million allowances (as opposed to more than double that amount put on offer in July). Apparently, intensified coal-to-gas switching, which translated into lower CO2 emissions, started to have meaningful effects on the demand for allowances. Another factor depressing the price was the appointment of a new prime minister in the UK whose strong support for leaving the EU on October 31 with or without a deal was seen as decreasing the chances for a negotiated divorce settlement, which implied less predictability about the UK’s future participation in the EU ETS and, by extension, less certainty about the short term supply-demand equilibrium in the market. As a result, the average CO2 price in August fell to 27 €/t from 27.9 €/t in July, a first decline in that month during the third trading period (which began in 2013). In the middle of September, spot prices rose temporarily in the aftermath of the attack on Saudi oil facilities which increased distress in the wider energy market, before returning to levels close to the 25 €/t mark seen offering enough buy-side support. That support, however, gave away on the last day of the quarter, when the price slipped below 25 €/t and, at the same time, broke through the 200-day moving average, an important resistance level that was last breached in February this year.

All in all, the average quarterly CO2 spot price in the reference period rose by 6% compared to Q2 2019, putting further pressure on carbon-intensive generation capacities, especially in the coal-fired sector. At 27 €/t, the average price of one allowance in Q3 2019 was 45% higher compared to the same quarter a year ago (18.83 €/t).

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. In Q3 2019, as in the previous two quarters, both the free allocation and auctioning of emissions allowances by the UK government were suspended. The resumption of auctioning and free allocation is expected after a deal has been reached between the EU and the UK. Meanwhile, the reduced supply of allowances stemming from the significant UK volumes blocked from entering the market puts upward pressure on prices.

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

Source: S&P Global Platts
• **Figure 5** reports on extra-EU thermal coal import sources and monthly amounts of imports of the commodity into the EU. Provisional Eurostat data show that in the third quarter of 2019 thermal coal imports from outside the EU reached 18.3 Mt, beating the record low amount from the previous quarter and establishing a new all-time minimum. The volume of imported coal in the reference quarter came 39% lower compared to the same quarter of 2018 (30.0 Mt). This reflects the sharp fall of coal use in electricity generation in the EU (see Figure 9) and the adverse conditions for coal-fired generation in the quarter (see Figure 12). In Q3 2019, the estimated EU import bill for thermal coal amounted to €1.5 billion, 45% lower compared to Q3 2018, exceeding the year-on-year decline in imported volumes due to lower commodity prices.

• The largest share of extra-EU thermal coal imports in the reference quarter came from Russia, accounting for nearly two thirds (65%) of the total. Russia continued to hold a strong position in the European thermal coal market. Russian suppliers steadily increased their share in the last couple of years, building it up from 40% of all imports in 2016 to 48% a year later and 52% in 2018, mainly at the expense of their Colombian and US competitors. 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 exporters to expand their presence in the European market. The second most important thermal coal import source was Colombia, although its share fell from 13% in Q2 2019 to 10% in the reference period. The United States was the third most important thermal coal trading partner of the EU in the reference period, accounting for 8% of all imports (up from 7% in Q2 2019). Australia accounted for 6% of EU’s thermal coal imports in the reference period, trailed by South Africa (4%) and Kazakhstan (2%). The Indonesian share diminished to 0.2%.

• The decline in thermal coal shipments in the reference period could be observed in all major EU importers. Deliveries to German and Dutch terminals (calculated together as many German plants are supplied via Dutch ports) fell by 33% year-on-year to 7.4 Mt and only started to pick up slightly towards the end of the reference quarter as utilities embarked on restocking their plants ahead of the winter season, narrowing the contango on the forward curve (see Figure 3). Restocking activity was visible also at Polish terminals, where imports increased by nearly a third to 3.3 Mt in the reference quarter compared to Q2 2019 (but were still 20% down year-on-year). In the rest of the major markets, coal-to-gas switching generally reached high intensity and coal imports continued to hover close to record lows from the previous quarter, with Italy registering 1.6 Mt of imports (-42% year-on-year), France 1.5 Mt (-32% year-on-year) and Spain 0.9 Mt (-79% year-on-year). The most dramatic drop in thermal coal deliveries (by 86 % year-on-year to 0.2 Mt) was recorded by the UK which fell behind Finland (0.6 Mt), Portugal (0.3 Mt) and Romania (0.26 Mt).

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**Figure 5 – Extra-EU thermal coal import sources and monthly imported quantities in the EU-28**

![Graph showing thermal coal import sources and monthly quantities in the EU-28](image)

*Source: Eurostat*
2 European wholesale markets

2.1 European wholesale electricity markets and their international comparison

- The map on the next page shows, that wholesale electricity prices across Europe varied considerably in Q3 2019. While the baseload power in Malta cost more than 66 €/MWh on average, it sold for roughly half of that in Norway in the reference quarter. A similar, if a little smaller, divide could be observed between Greece and Belgium. The differences could be partly explained by interconnection insufficiencies or outages, partly by the effect of rapidly growing and unevenly distributed renewable output and also by the significantly strengthened CO2 price which has a varied impact on individual markets, depending on the local generation mix. This trend, coupled with several critical grid situations which occurred in the reference quarter, points to the need for increased investment in strengthening network resilience and expanding cross-border capacities.

- Apart from Malta (66.3 €/MWh) and Greece (62.4 €/MWh), the highest average wholesale electricity prices in Q3 2019 were reported from Romania (58.7 €/MWh), Poland (57.9 €/MWh) and Hungary (56.4 €/MWh). Some of these countries traditionally rely on imports of electricity (Greece, Hungary), and some faced increased production costs in the reference quarter due to high CO2 prices penalizing their carbon-intensive generation mix (Poland, Greece). Romania suffered from low hydro output and had to resort to increasing imports. The lowest quarterly wholesale prices were recorded in Norway (33.6 €/MWh), which benefited from ample hydro reservoir levels and rising wind generation, and Belgium (35.2 €/MWh), where exceptionally high nuclear output and rising renewable penetration compressed baseload contracts.

- The pan-EU average of wholesale baseload prices reached 47.0 €/MWh in the reference quarter, down 21% in a year-on-year comparison. Compared to Q2 2019, the wholesale benchmark rose by 8.6% on the back of low hydro generation in the Balkans and higher carbon prices, which were only partly compensated by the expansion of renewables and feeble demand.

- In terms of price developments in individual markets, the biggest (and only) year-on-year price swings in the upward direction took place in Bulgaria (+53%) and Romania (+6%), whereas the largest falls could be observed in Belgium (-42%), the UK (-39%) and France (-38%).

- In July Ukraine took a big step forward towards the liberalized model of the electricity market, holding its first ever day-ahead and intraday trading sessions and replacing mandatory purchases of all electricity produced in the country by a state company Energorynok for an administratively set price. The average baseload prices in both the integrated power system of Ukraine and the Burshtyn Island\(^2\) reached levels similar to that of neighbouring Poland and Hungary.

\(^2\) Burshtyn Island is an area in Western Ukraine comprising the Burshtyn coal-fired power plant and several substations. It has been synchronized and connected to the Continental European (UCTE) grid via the power systems of Hungary and Slovakia since 2002.
Figure 6 – Comparison of average wholesale baseload electricity prices, third quarter of 2019

Source: European wholesale power exchanges, government agencies and intermediaries
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 a peak in divergence at the end of Q2 2019, wholesale prices across different regional markets in Europe began to converge again in the reference period. This was due to the fact that average prices in countries and regions which traditionally form the lower part of the spectrum (Nord Pool, Germany, France) registered increases across the board in Q3 2019, while markets which usually find themselves in the upper part of the range saw baseload prices stabilizing (Italy) or going down (Greece, Spain).

Figure 8 shows the evolution of the European Power Benchmark (EPB) spot wholesale electricity price, as well as German day-ahead and year-ahead contracts for baseload delivery 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. The reference period witnessed a relatively high degree of convergence between the EPB and day-ahead German contracts which were both reacting to the developments in the carbon and input fuels markets and to swings in renewable generation. German day-ahead prices also showed only slightly larger volatility than the EPB, which is unusual given the large degree of renewable penetration in the German market. Year-ahead German prices were influenced by the movements in year-head prices of coal, gas and emission allowances, rising by 2% on average in Q3 2019 compared to Q2 2019 and finishing the quarter with a 10 €/MWh premium over the day-ahead German contracts. About the same gap stood between year-ahead and day-ahead gas prices at the end of the reference period (see Figure 3).

Source: Platts, European power exchanges. In different periods minimal and maximum prices may refer to different power regions. The shaded area delineates the spectrum of prices across EU regions.

• Figure 9 shows the evolution of the electricity mix in the EU-28. The dominant theme influencing the structure of the generation in the reference quarter continued to be the declining role of coal and lignite which were increasingly squeezed out by gas and renewables. Compared to the same quarter of the previous year, the share of fossil fuels (solid fuels, gas, oil) in Q3 2019 decreased from 42% to 39%, while the share of renewables (hydro, biomass, wind and solar) rose from 31% to 33% on the back of strong wind output growth. The share of nuclear generation remained broadly stable at 26% as an exceptional performance of the Belgian fleet compensated for decreases in generation volumes in France, Germany and the UK.

• Falling demand throughout the quarter and rising renewable generation limited the space for thermal power plants. Within the fossil fuels complex, the effect of high CO2 prices and associated coal-to-gas switching was visible. Less CO2-intensive gas generation gained share at the expense of coal and lignite in nearly all countries with switching potential and reached a 25% share in the overall mix in Q3 2019 (compared to 20% in Q3 2018). In absolute terms, gas-fired power plants increased their output by 28 TWh year-on-year in the reference quarter which was the largest gain of all generation sources. Solid fuels, on the other hand, saw their share reduced to 13% in the reference quarter (from 20% in Q3 2018). That in absolute terms translated into 50 TWh less electricity produced by burning coal and lignite than in Q3 2018. Renewables generated 12 TWh of electricity more in the reference quarter than in Q3 2018.

• Between hard coal and lignite (the distinction between them is not visible in Figure 9), 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 the low price/production cost 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 bigger carbon footprint (by about 20%) than their coal peers per MWh, which penalizes the former ones more when emission allowances become costlier. In Q3 2019, record high CO2 prices and increasing renewable penetration (which kept average electricity prices in check) coalesced to undermine the economics of some of the least efficient lignite units. As a result (and also thanks to some plant closures), lignite-based generation in Q3 2019 fell by 24% year-on-year (or 17 TWh), while coal-fired generation plunged by 46% year-on-year (or 33 TWh). Thus, the share of coal in the EU power mix in Q3 2019 fell below that of solar energy, and the share of lignite was lower than that of onshore wind.

![Figure 9 – Monthly electricity generation mix in EU-28](image)

Source: ENTSO-E, Eurostat, DG ENER

• Figure 10 depicts the evolution of the monthly renewable generation in the EU, alongside the share of renewables in the electricity generation mix. In Q3 2019 the the rising role of renewable generation was on display, reaching 33% share, the highest for a period between July and September so far. In the previous two years the renewable share in Q3 was lower than 31%.

• The main driver behind the increasing importance of renewable power in the reference quarter was wind generation which in its onshore segment expanded by 14% year-on-year (or 7.9 TWh) and in the offshore sector recorded a 40% year-on-year jump in generation (or 4.3 TWh). Solar-based generation in Q3 2019 grew by 2.7% (or 1.2 TWh) compared to Q3 2018. Biomass-based generation registered a 2% year-on-year rise in output. A measurable decline of 2% compared to Q3 2018 occurred in hydro generation in Q3 2019.

• Wind-powered electricity generation recorded a strong third quarter in 2019 and with a 11.2% share in the mix overtook the hydro sector as the largest contributor to renewable output. The share of solar grew to 6.6% in Q3
2019, compared to 6.3% in Q3 2018. Biomass saw its share in the mix going slightly up to 4.6% in the reference quarter (from 4.3% a year before).

- The largest increases in wind output came from Germany, Spain, France and the UK. Belgium, Greece, Portugal and Poland also provided significant contributions in this respect. Offshore wind farms in Belgium expanded their generation by 86% year-on-year (or 0.5 TWh) in the reference quarter.

- At 33%, the combined share of hydro, biomass, wind and solar in the EU electricity generation in Q3 2019 was higher than in other major economies. The share of renewables in the US power mix in the reference quarter stood at 15%, whereas in China and India renewable energy constituted 26% and 27% of their respective total power generation during the same quarter.\(^3\)

Figure 10 – Monthly renewable electricity generation in the EU and the share of renewables in the power mix

- Figures 11 and 12 report on the profitability of gas-fired and coal-fired electricity generation in Germany, the UK, Spain and Italy by looking at the spread indicators on selected wholesale markets. In Q3 2019, gas further increased its gains over its main competitor compared to the previous quarters thanks to its low price and persistently high prices of emission allowances which penalize coal more because of its greater carbon-emission intensity.

- As shown in Figure 11 In all countries under observation, the profitability of gas generation stayed in the positive territory throughout the reference quarter, with Italian and Spanish gas plant operators achieving higher margins than their peers in Germany and the UK due to lower power prices in Germany and additional carbon-related costs in the UK. As spot gas prices hovered consistently close to multiyear lows and CO2 prices rarely dipped under 26 €/t for the greater part of Q3 2019, the main factor driving clean spark spreads in the reference period were wholesale electricity prices in individual markets. In the UK, the spreads were the lowest among the compared group due to a combination of stagnating power prices and the local carbon price support which puts extra costs on emitting plants. CCGT plant operators in Britain, however, may also rely on revenues from the capacity market. EU-wide gas generation reached a peak of more than 61 TWh in July, helped by record cooling demand during summer heatwaves and temperature-related capacity curtailments in some countries. This was in line with the developments in clean spark spreads in the markets under observation.

\(^3\) 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 contain burning of biomass.
Figure 11 – Evolution of clean spark spreads in the UK, Spain, Italy and Germany, and electricity generation from natural gas in the EU

- Figure 12 demonstrates that coal generators across Europe were operating in a very adverse environment in Q3 2019. In the UK, higher costs for carbon, falling power prices and slightly increased input fuel costs meant that clean dark spreads sank deeper in the negative territory, leaving very little room for coal plants in the British merit order. A similar story played out in Germany, the only difference being the absence of carbon price support in the German market. Spanish clean dark spreads decreased the most of the whole group, reacting to significant falls in local power prices and diving below zero for the first time in many years. Spain saw the strongest swings in coal and gas generation (in relative terms) in the reference quarter. The only market where clean dark spreads for a plant with an average efficiency managed to stay positive was Italy, mainly thanks to relatively higher power prices there. However, even the Italian market saw a significant shift from coal to gas, as the gap between the local clean spark and dark spreads widened during Q3 2019. The total coal generation in the EU corresponded with falling clean dark spreads, plunging by 46% year-on-year to 39 TWh in the reference quarter. In August, coal-fired generation in the EU reached its lowest level on record.

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

Source: ENTSO-E, Eurostat, Bloomberg
• The difference between clean spark and dark spreads reached record levels in Q3 2019, driving the intensification of coal-to-gas switching across Europe. The impacts in individual markets in the reference quarter could be seen in Figure 13. In Spain, the switching channel was exhausted almost entirely, with 86% of last year’s Q3 coal and lignite output substituted by gas which increased its foothold in the mix by 93% year-on-year. Apart from low dark spreads, a number of policy changes the Spanish government introduced over the last couple of years contributed to this strong swing. The most important of them happened last year when the tax on burning gas for electricity production was revoked (and retained for coal usage) and targeted capacity payments for thermal plants were abolished, which deprived coal plants of additional source of revenue. Gas, on the other hand, managed to substitute the whole generation gap left by coal (and lignite to a lesser degree) and to increase its presence in the mix even beyond that, filling in for low hydro output and for decreased imports from Portugal.

• The case of Germany, where coal and lignite suffered the largest losses in absolute terms in Q3 2019, shows that even lignite power plants with their relatively low input costs have become vulnerable in the world of high carbon prices. The slide in lignite generation levels stemmed partially from retirements. However, the average utilization rate of plants remaining in service (on a same-unit, capacity-weighted basis) fell from 79% in Q3 2018 to 57% in Q3 2019, a significant change considering the fact that lignite-fired plants have always been regarded as a baseload-providing source. The unique combination of cheap gas and expensive carbon meant that for the first time ever, gas-fired power plants displayed better economics than parts of the lignite fleet. The decline in lignite-based generation had also far-reaching impacts on cross-border power flows. It is telling that German net exports during the reference quarter totalled only 1.3 TWh, compared to 11 TWh in Q3 2018 when CO2 prices were 40% lower. Collapsing exports also help explain why the absolute year-on-year increase in gas generation in Germany in Q3 2019 was so small (3.6 TWh) in relation to the fall in coal and lignite output (-18.2 TWh combined). The missing volumes were replaced by cheaper sources elsewhere, most importantly by increased generation from high Alpine hydro reservoirs and Belgian nuclear units.

• In Italy, gas was not able to push out its main competitor entirely out of the merit order, as clean dark spreads in the country stayed predominantly in the positive territory. But gas-fired generation, which offered much higher margins, gained ground also against oil and some imports as well. In France, where coal-fired generation almost ceased since spring, gas replaced weak hydro and nuclear output. In other countries under observation, gas was unable to fully capitalize on coal’s decline, as cheaper alternatives such as renewables or imports used this opportunity instead, and feeble demand reduced the space for thermal plants in general. A prominent example is the Netherlands, where renewable output jumped by 28% year-on-year in Q3 2019, driven by a surge in solar generation. In Poland, in turn, the 2.1% year-on-year drop in electricity consumption in the reference quarter covered the entire fall in the local coal generation (-0.8 TWh). Declining consumption and rising renewable generation curbed both coal and gas in the UK and Ireland.

• A further increase in the intensity of fuel switching in the short term seems unlikely due to operational inertia of some coal plants (stemming from heat supply obligations, hedging positions, long-term fuel contracts or grid stability considerations) and limited gas generation capacity in some markets.

• This year’s consistently worsening conditions for coal-firing assets started also to materially affect their future prospects. Around half of the Spanish coal fleet is expected to be retired by the end of the next year, partly as a result of stricter emission standards requiring significant investments which the plant owners decided not to undertake. Many additional retirements have been announced or brought forward in other countries. This shows that generators have largely factored in the current CO2 price level as a new normal and are adapting their portfolios accordingly, making the current changes in the mix harder to reverse. Thus, in some Member States with government-mandated coal exit deadlines, the end of coal-based generation could happen sooner thanks to market forces only. The first such market-driven abandonment of coal use in the electricity sector will happen next year in Austria.

• The increased switching activity has both short term and long term ramifications for the EU ETS. As lower coal burn decreases demand for emission allowances, the switching puts downward pressure on carbon prices. The carbon footprint of EU’s electricity sector decreased roughly by 12% year-on-year during the first nine months of 2019. Additionally, the material decline in the utilization rates of coal- and lignite-based power plants, which puts their status as baseload-providing assets into question, influences hedging strategies of major utilities who hold large amounts of emission allowances currently in circulation. As coal-to-gas switching lowers generators’ hedging requirements, this frees up more allowances for other players in the market and depresses prices.

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4 Calculations based on data from Energy Charts of Fraunhofer-ISE.
**Figure 13** – Coal-to-gas switching in selected EU countries in Q3 2019 compared to Q3 2018

![Coal-to-gas switching chart](image)

Source: ENTSO-E, Eurostat, DG ENER

- **Figure 14** shows the monthly frequency of the occurrence of negative hourly wholesale electricity prices in selected EU 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). 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 the costly and high-maintenance operation of restarting the facility when they are required again.

- At 64, the number of hours with negative wholesale prices in Q3 2019 was relatively high compared to the previous Q3 last year when only 8 such instances were counted, but similar to Q3 2017 when hourly prices were lower than zero in 68 cases. All the falls into the negative territory in the reference quarter were almost evenly split between August and September. As is usually the case, Germany had the highest number of negative hourly prices (26) in Q3 2019, trailed by Belgium (16) and Denmark's East zone (14). In August, most negative pricing was concentrated in the afternoon hours of the weekend between 10th and 11th when sunny weather coincided with good wind availability in the North Sea.

- Another noteworthy concentration of negative hourly prices occurred on Sunday, September 15th in the afternoon when low weekend demand met with strong winds in Denmark and northern Germany. During a large portion of the weekend, Denmark’s wind generation surpassed its total electricity consumption. This triggered exports to Norway, Sweden, Germany and (via a new interconnector) to the Netherlands. However, as wind generation increased also in neighbouring Germany, power started to flow northwards in the opposite direction, turning Denmark into a transmission bridge between Germany and the Nordics. The rising tide of German wind exports caused prices in the neighbouring Danish zone to go below zero for several hours. For reliability reasons, the Danish TSO kept around 0.5 GW of fossil-based generation online during the weekend. The episode highlighted vulnerabilities in the local transmission networks. The power surge in the German grid stemming from strong wind output was so extreme that the local TSO asked its Danish counterpart to curtail 1.3 GW of wind generation. This typically brings about additional system costs as the curtailed generators have to be remunerated (the estimated claims of compensation for curtailed generation in 1Q 2019 in Germany rose by 60% year-on-year to €364 million according to the German energy regulator (BNetzA), with most of the increase occurring in the northern regions with a high concentration of wind generation\(^5\)). The northbound flows of German electricity despite the negative pricing in the Danish zone underlined known market constraints within Germany and pointed to the need of increased coordination and careful planning with regard to future generation capacity additions.

- A recently published study by BNetzA, which analysed market data from the period between 2016 and 2018, revealed that many conventional power plants reacted to negative prices only to a limited extent, often due to the lack of flexibility stemming from heat supply obligations or due to self-generation incentives. A survey of plant

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\(^5\) Bericht zu Netz- und Systemsicherheitsmaßnahmen - 1. Quartal 2019, p. 27.
operators showed that CHP units in particular would still generate power even if hourly prices dropped to minus 100 €/MWh. Bottlenecks between high-voltage and distribution grids were also seen as a contributory factor.

Figure 14 – Number of negative hourly wholesale prices on selected day-ahead trading platforms

- **Figure 15** compares price developments in the wholesale electricity markets of selected major economies. Day-ahead markets in Japan and the US underwent a turbulent summer this year, both registering significant price spikes in August. In the US, the heightened levels were limited to the ERCOT region (corresponding roughly to Texas) where high cooling demand driven by extremely hot weather combined with low wind availability and pushed prices towards the 9000 USD/MWh ceiling for several hours. The local grid operator had to declare an energy emergency, calling on all power plants to ramp up generation levels and asking customers to conserve. The rest of the country saw much more moderate price rises thanks to very low costs of burning domestically produced natural gas which serves as the fuel to marginal power plants in most local electricity markets. By the end of the reference quarter the situation stabilized and the average US prices returned to around 30 €/MWh, about 20% lower than their EU peers.

- High cooling demand spurred by summer heatwaves also influenced the Japanese wholesale market where average prices climbed above 86 €/MWh in August and settled at 77 €/MWh in September, about twice as high as the EU average and higher than in any individual EU market for that month. The Tokyo Commodities Exchange started trading Japan’s first electricity futures in September, a step that should encourage competition in the market and entice new entrants to the sector which has been undergoing liberalization since 2016. In another move that should help new entrants compete with regional incumbents, baseload electricity auctions started to be held in August. These will enable retailers to purchase power at fixed prices, limiting their exposure to price spikes on the spot market. Wholesale electricity prices in Australia fell under 45 €/MWh on average during Q3 2019, compared to 51 €/MWh in the previous quarter, on the back of mild winter weather in the Southern Hemisphere.

Figure 15 – Monthly average wholesale electricity prices in Europe, US, Japan and Australia (D-A markets)

Source: European Power Benchmark, JPEX (Japan), AEMO (Australia) and the average of PJM West, ERCOT and CAISO regional wholesale markets in the United States
2.2 Traded volumes and cross border flows

- **Figure 16** shows the monthly evolution of electricity traded volumes, including exchange-executed trade and over the counter (OTC) trade on the most liquid European markets. Due to data availability issues, only July and August 2019 were added. The largest trade volumes could be again observed in the German market, followed by the UK and the Nordic markets. France and Italy came fourth and fifth respectively in the two-month period.

- Traded volumes of electricity show a high degree of seasonality, with activity usually slowing towards the summer months and picking up again after the holiday season. Unlike in previous years, however, the traded volumes picked up in July compared to June, before going down again in August. Compared to the same two months last year, the trading activity increased by 2%. The largest relative gains were recorded in Spain (+27%), the CEE region (+11%) and France (+7%), whereas Belgium (-57%), the Nordic markets (-18%) and the UK (-4%) experienced the biggest slides.

**Figure 16** – Monthly traded volume of electricity on the most liquid European markets

![Graph showing monthly traded volume of electricity on the most liquid European markets]

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

- **Figure 17** shows the comparison of volumes in different market segments of electricity trading on the most liquid electricity trading platforms in Europe in July and August. In different segments of power market trading the volume dynamic was mixed. The 2% rise in the overall trading activity in the two-month period was driven by increased volumes of exchange-traded contracts (+10% year-on-year) which more than compensated for a fall in over-the-counter (OTC) trading (-1%). Consequently, the share of exchange-executed trade increased from 31% to 33% year-on-year. The year-on-year rise of exchange-based activity was driven mainly by the German futures market, where traded volumes jumped by 52 TWh, and to a smaller extent by the markets in the CEE region (+10 TWh). Belgium, the UK and the Nordic markets saw exchange-traded volumes go down by 14 TWh in total. In the OTC segment, Spain reported a significant 46% boost compared to the last year, specifically in cleared contracts. The shift from OTC to exchange-executed trading comes as more and more smaller producers enter the market and for reasons of convenience meet at a central marketplace rather than trade bilaterally.

**Figure 17** – Electricity traded volumes in selected day-ahead, forward and OTC markets in July and August of 2019

![Graph showing electricity traded volumes in selected day-ahead, forward and OTC markets]

Source: Platts, wholesale power markets, Trayport, London Energy Brokers Association (LEBA) and DG ENER computations
Figure 18 reports on the regional cross-border flows of electricity. The CWE region continued to hold the position of the leading exporter, having plentiful and diverse generation capacities, competitive prices and a central position suitable to supply all the other regions. Monthly net export flows were relatively stable, adding up to 21.8 TWh for the whole reference quarter (+20% compared to Q3 2018). Strong wind and hydro generation and an exceptional performance of the Belgian nuclear fleet contributed to this result.

Italy remained by far the largest importer of electricity in Q3 2019, receiving 8.7 TWh of net inflows, mainly from Switzerland and France and, to a lesser extent, Austria. A minor fraction of this volume was shipped to Malta. The net Italian position improved compared to the previous Q3 thanks to increased domestic hydro and gas generation. This was reflected also in record exports to Greece which reached 0.9 TWh on a net basis in the reference quarter (as opposed to 0.3 TWh of net imports from Greece in Q3 2018). The second largest importer region, the British Isles, saw its net purchases in Q3 2019 remain broadly stable at 4.9 TWh (-3% year-on-year), as lower consumption made up for decreased domestic generation. The CEE region’s net position shifted from a mild surplus in Q3 2018 to a 4.7 TWh deficit on the back of poor hydro generation and reduced lignite-based output. South Eastern Europe also had to sharply ramp up imports in Q3 2019 to 3.5 TWh due to dry conditions, which curbed hydro generation, and high carbon prices faced by lignite-burning units in the region.

The Nordic region went through a volatile quarter, swinging between surplus and deficit in Q3 2019. Compared to the last Q3, the region shifted from being a net importer (-0.7 TWh) to exporting 1.7 TWh on a net basis thanks to strong Swedish hydro generation in July. The Iberian Peninsula imported 2.5 TWh on a net basis in the reference quarter (down 22% from Q3 2018).

Figure 18 – EU cross border monthly physical flows by region

Key to country distribution in regions: CWE (AT, DE, BE, NL, FR, CH), CEE (CZ, HU, PL, 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 19 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. In Q3 2019, the position of the Baltic region continued to worsen as it imported almost the same amount of electricity as generated domestically (compared to 77% of domestic output in Q3 2018). However, the situation began to improve towards the end of the quarter. High shares of imports indicate difficulties facing domestic generation assets or more favourable price conditions in the neighbouring areas. High CO2 prices, which negatively affect the competitiveness of fossil-based power plants in the Baltic region, played a crucial role in the developments there.

In terms of relative shares, Italy retained the position of the second biggest importer relative to its production. For the rest of the regions, the net imports of exports didn’t 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 Q3 2019, the net CWE exports corresponded to 6.7% of the regional generation.

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, 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). The -100% level means the same amount of electricity is imported as produced domestically. 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 July 2019, the monthly average baseload electricity prices in the CWE region jumped 21% month-on-month to 39 €/MWh in response to rising CO2 and fuel costs which weighed on thermal plants in Germany and the Netherlands (Figure 20). Temperature-related spikes in demand contributed to the power price inflation. During the rest of the quarter monthly average baseload prices were holding slightly below 36 €/MWh thanks to increased wind generation, feeble demand and falling carbon costs. Compared to Q3 2018, the average baseload price in the region declined by 34% to 36.9 €/MWh in the reference quarter. Average peakload prices initially followed their baseload peers, but the spread between them widened in September, in line with regular seasonal trends.

- Increased CO2 prices, intensified coal-to-gas switching and variations in hydro reservoir levels significantly influenced generation and cross-border flow patterns across the region. Thus, Austria and Switzerland both recorded a 22% year-on-year jump in generation in Q3 2019, mainly thanks to higher hydro output which benefited from large melting snowpack in the Alps. Belgium saw its total output levels increase by 47% year-on-year on the back of exceptionally good nuclear availability, while the Dutch mix profited from increased solar and wind generation. In absolute terms, the combined generation volumes of Austria, Switzerland, Belgium and the Netherlands increased by 13 TWh, while German generation plunged by 14 TWh in the reference period. The position of France as the largest exporter in the region didn’t undergo any material changes.

- A new 700 MW interconnector linking the Netherlands and Denmark for the first time was put into operation in September. The 325km subsea high-voltage direct current cable is an initiative of the two countries’ TSOs. The so-called Cobra cable will enable the Netherlands to import more renewable electricity, mainly wind-based, from the Danish grid. The cable connection has been designed in such a way that it will also be possible to connect an offshore wind farm at a later stage.

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

- Figure 21 shows the average regional day-ahead prices in the reference quarter. Most of the time the prices displayed a high degree of convergence, moving between 20 and 50 €/MWh, with two larger dips caused by renewable output surges and low weekend demand. The first occurred on August 10th, when wind and solar generation breached 100 GW across the continent, driving hourly prices into the negative territory in Germany, Denmark and Belgium. France avoided prices below zero as its nuclear fleet was ramped down sufficiently to accommodate the active solar and wind capacities peaking at 14 GW. The second major fall in prices happened during the last weekend of the reference quarter, when German renewable generation peaked above 50 GW on Saturday and Sunday, covering up to 90% of domestic consumption in the afternoon.

- On the other side of the price spectrum, two events stood out when daily baseload contracts in the region touched or breached 50 €/MWh. High cooling demand and various temperature-related generation restrictions sent prices up during the July heatwave. The biggest effects were felt in France where daily average contract peaked at 52.93 €/MWh on July 24th, drawing imports from Germany, the UK, Belgium and even Spain at times. Italy remained the
only country to import French power during the episode. Gas generation could do little to help ease the strain on the grid since it was already operating close to its maximum capacity and nuclear availability sank to 60%. Prices climbed up noticeably also at the end of August amid a lull in wind availability and higher temperatures.

Figure 21 – Daily average power prices on the day-ahead market in the CWE region in Q3 2019

As shown in Figure 22, the French nuclear generation was relatively underwhelming in Q3 2019, down 3.6% compared to the same quarter last year amid heat-related curtailments and other unexpected outages. In July, nuclear output reached its lowest point during the 30th week, at the height of the heatwave, when high temperatures in rivers into which cooling water from plants is discharged forced 6.5 GW of reactors out of the grid. Generation output took another hit in the second half of September due to a strike that affected several plants and due to low river flows on the Rhone, Meuse and Moselle which also restricted operation at a few units. Seven out of the total of 58 French reactors are planned to undergo extended overhauls this year, six of which were ongoing during the reference quarter. Belgium, in contrast, experienced a 125% year-on-year jump in nuclear output in Q3 2019. Thanks to Doel 3 and Tihange 2 reactors returning from outages in July and other scheduled maintenances being postponed for several months, nuclear availability was at its full 6 GW capacity throughout the rest of the reference quarter, with all seven reactors online. This was in stark contrast to last year, when the country’s nuclear fleet was operating at historically low levels due to unplanned outages. Baseload prices in the Belgian market in Q3 2019 were on average the lowest in the whole region, beating France by 0.5 €/MWh.

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

Source: ENTSO-E
3.2 British Isles (UK, Ireland)

- **Figure 23** informs about the monthly volumes and prices on the day-ahead markets in the United Kingdom and Ireland. In July baseload and peakload prices increased by 7% and 9% respectively month-on-month, responding to rising carbon and fuel prices and reduced flows from the continent occupied by meeting heatwave-related demand spikes. A decreasing trend set in afterwards, however, propelled by a turnaround in the carbon and fuels markets, higher renewable generation, feeble demand and a return of some nuclear capacities into service. September saw average baseload prices settling below 42 €/MWh, a two-year minimum. The peakload contract, meanwhile, finished the reference quarter with a 4 €/MWh premium over its baseload peer. Compared to Q3 2018, the average baseload price on the British Isles declined by 54% to 44 €/MWh in the reference quarter.

- Trading activity on the day-ahead market continued to be record low in both markets. Compared to the same quarter last year, the volumes fell by 45% in Q3 2019.

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

- **Figure 24** shows that average daily baseload electricity prices in the UK (N2EX) moved between 30 and 50 €/MWh during 3Q 2019, responding to renewable availability and the developments in the price of gas, which is the fuel that sets marginal electricity generation costs most of the time in the British market. Prices on the all-island Irish market generally followed the UK contract, albeit with larger volatility due to fluctuations in wind generation which constitutes a more important part of the power mix on the Irish island compared to the UK, covering around 35-45% of consumption during the reference quarter. New installations and favourable weather conditions contributed to a 27% year-on-year rise in the wind (onshore) output on the island during the quarter. Coal-based generation, on the other hand, suffered from negative clean dark spreads, falling by 84% year-on-year.

- On August 9th, the British electrical system experienced a power outage that affected 1.1 million customers who were disconnected for around 50 minutes. This was the largest power cut in over a decade in the UK. The technical report of the system operator concluded that the event started with a lightning strike after which two larger generators and some smaller embedded generation tripped, reducing their combined supply to the grid by nearly 1.1 GW. This caused a rapid fall in network’s frequency, which in turn induced a further 350 MW of embedded generation to go offline. The system operator was keeping 1 GW of automatic reserves to respond to such an event, and using all the backup power and other instruments (including 472 MW of battery storage) managed to stop the frequency fall at 49.1 Hz. However, just as the frequency began to climb up again, a further trip of a 210 MW gas turbine occurred, taking the cumulative loss of generation to 1.7 GW. Frequency than began to fall again and at 48.8 Hz secondary backup systems acted automatically to disconnect roughly 5% of demand in order to enable frequency recovery and ensure the integrity of the network. Apart from customers without power, other effects included major disruption to parts of the rail network and other critical facilities such as hospitals or airports. A wide discussion about the costs and benefits of ensuring security of supply took place in the aftermath. The system operator is looking to introduce new constraint management products in order to address the risk of similar incidents repeating in the future. It is also considering frequency and voltage stability contracts for up to 6 GW of capacities that can deliver inertia. This is a force that comes from heavy spinning generators and slows down the grid’s reaction to a deficiency or surge in generation which gives the grid operator more time to correct an imbalance.
Figure 24 – Daily average electricity prices on the day-ahead market in the UK and Ireland

Source: Nord Pool 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. Increased CO2 prices (higher than on the continent due to the carbon price support mechanism) and very competitive gas prices, pushed coal-fired generation out of the UK merit order this year. The small coal-firing activity reported in August and September, which took place despite deeply unfavourable margins (see Figure 12), was most likely the result of a need to deplete remaining fuel stocks at units destined to be retired soon.

- British electricity generation recorded a 1.5% year-on-year fall in Q3 2019, driven by a 21% decrease in nuclear output which was caused mainly by the extended maintenance of the Hunterston B and Dungeness B reactors. The share of renewable energy sources in the mix rose from 33% in Q3 2018 to 39% in the reference period thanks to large gains in offshore wind generation (+43% year-on-year). The combined share of gas and coal, meanwhile, declined from 41% to 40% in Q3 2019 as both fuels suffered year-on-year falls in utilization (0.3 TWh for gas and 1.1 TWh for coal in absolute terms), which highlighted the exhausted opportunities for coal-to-gas switching in the UK market.

Figure 25 – Approximated weekly evolution of the UK electricity generation mix in Q3 of 2018 and 2019

Source: ENTSO-E, Eurostat, BEIS
3.3 Northern Europe (Denmark, Estonia, Finland, Latvia, Lithuania, Sweden, Norway)

- As shown in Figure 26, the average monthly baseload price in the Nord Pool area reached more than 35 €/MWh in July, moving sharply higher compared to the previous month on the back of low wind availability, rising carbon and fuel prices and reduced imports from Russia. Underwhelming generation in Sweden, Finland and Denmark pushed prices even higher in August. Afterwards, the overall tightness in the regional generation-consumption balance eased thanks to higher hydro and wind output which together with decreasing carbon prices translated into lower monthly average baseload contracts in September. Compared to Q3 2018, the average system baseload price declined by 31% in the reference quarter.

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

- Figure 27 shows the weekly evolution of the combined hydro reservoir levels in the Nordic region (Norway, Sweden and Finland) in 2019 compared to previous six years. Hydro stocks in the region started the reference quarter at a high level but stagnated in the first six weeks due to dry conditions, above-average temperatures and rising Norwegian exports which stepped in for lower generation in Sweden and Denmark. Reservoirs started rising measurably only in the second half of August thanks to increased precipitation levels in Norway and despite strong Norwegian and Swedish electricity exports. Wet conditions persisted and towards the end of the reference period and helped the stocks breach 100 TWh at the end of September. The total hydro generation in the region increased by 2.2 TWh year-on-year thanks to strong Swedish production (+2.5 TWh) which was concentrated mainly to July and September and outweighed a minor decrease in Norwegian output (-0.5 TWh).

Figure 27 – Nordic hydro reservoir levels in 2019, compared to the range of 2013-2018

Source: Nord Pool spot market
Figure 28 shows that average daily prices across Northern Europe in Q3 2019 developed a regularly-structured pattern in which markets relying most on imports (the Baltics and Finland) witnessed the highest prices (with 13-14 €/MWh average premium over the system contract), while those that relied less on inflows from other markets (Denmark, Sweden) registered much lower average premiums over the system price (1.5-3 €/MWh). Norway reported daily baseload prices at or below the system price level throughout the reference quarter. There were two significant price dips driven by wind generation surges in Denmark and Germany (the second one from September is described in greater detail in Figure 14). The high import dependence of Finland and the Baltics was accentuated at the height of the July heatwave (on the 24th) when the day-ahead contract in those markets surged to 62 €/MWh, while the system baseload product traded at less than 39 €/MWh. Another spike came at the end of the reference quarter when annual maintenance on several interconnectors between Finland and Sweden coincided with reduced Finnish nuclear generation, sending prices in Finland and Estonia towards 90 €/MWh. Finland’s structural reliance on imports stems from a decade-long delay in the completion of the Olkiluoto-3 nuclear reactor. This deficit puts strains on transmission capacities with neighbouring countries.

Figure 28 – Daily average regional prices and the system price on the day-ahead market in the Nordic region

- Contributing to the net importer position of Finland and the Baltics were flows from the Russian and Belarusian zones which reached 3 TWh (on a net basis) in Q3 2019, down 16% compared to the same quarter last year. The decrease was apparently the result of summer plant maintenances which affected July export volumes stronger than in the past.

3.4 Apennine Peninsula (Italy, Malta)

- Italian monthly average baseload electricity prices (Figure 29) were stable in the third quarter of 2019, moving in a band between 49 and 52 €/MWh. The average baseload price for the reference quarter, at 51 €/MWh, was almost unchanged from the previous quarter. Increased carbon costs for the local marginal power plants nudged electricity prices higher in July, but then, as the CO2 market started to slide, the effect tapered off. Meanwhile, the peakload electricity contract displayed a greater volatility, even falling slightly below the average baseload price in August, before returning to a more usual premium over the baseload contract in September. Compared to Q3 2018, the average baseload price declined by 26% in the reference quarter.

- Several Italian power generators announced plans to convert a significant amount of coal-fired capacity to gas or build entirely new CCGT units. The move coincides with the planned launch of a capacity market this year and comes in advance of the phase-out of 7.2 GW of coal capacity scheduled for 2025. Capacity providers will be selected on the basis of regular auctions open to new and existing generators, including renewables, demand response providers and storage. Annual expenditure on the mechanism is forecast by the Italian TSO at €0.8-1.2 billion, which translates to 40GW of capacity at 25,000 €/MW. This compares with €1.2 billion of gross costs of the UK capacity mechanism projected for this year. Italy’s reserve margin has decreased considerably in the past two decades, with around 20 GW of thermal capacity retiring since 2012. This has exposed the northern regions of the country, where a lot of consumption is concentrated, to a greater risk of power outages.
Figure 29 – Monthly electricity exchange traded volumes and average day-ahead wholesale prices in Italy

Figure 30 shows the daily evolution of the national average price and the range of the regional price areas in the Italian market. Third quarter of 2019 saw several periods of increased volatility associated with weather-related increases in consumption which had to be met mostly with higher gas-fired output or ramped-up imports, driving up daily prices in the process. Despite an early return into operation of an important interconnector with Switzerland, the Italian gas-fired power generation reached 22.4 GW on July 25th, an eight-year maximum. Another peak came at the end of August, when higher prices in neighbouring France together with lower renewable output and rising gas use in power generation prompted the daily national average contract to surge above 70 €/MWh.

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 30, prices in the Maltese zone in most cases form the upper boundary of the whole spectrum of Italian regional electricity prices. Price spikes in the middle and towards the end of August were caused by unplanned cable outages in Sicily and reduced flows from the mainland.

Figure 30 – Daily average electricity prices in the Italian day-ahead market, within the range of different area prices

Source: GME (IPEX)
3.5 Iberian Peninsula (Spain and Portugal)

- **Figure 31** reports on the monthly average wholesale baseload and peakload contracts in Spain and Portugal. In July baseload prices went up 9% month-on-month to 51.5 €/MWh amid rising carbon and fuel costs and restrictions on imports from France, which met with increased demand (+9% year-on-year). During the rest of the reference period both baseload and peakload contracts declined thanks to falling CO2 prices, good wind and solar generation and reduced demand, finishing the quarter close from each other at around 42 €/MWh. Compared to Q3 2018, the average baseload price declined by 30% in the reference quarter. Compared to the previous quarter, the average baseload contract was down 6% in Q3 2019.

- A milestone was reached during an auction in Portugal in August which awarded 1.15 GW of solar PV capacity at an average price between 20 and 21 €/MWh. The auction saw one successful bid of just 14.8 €/MWh for a 150 MW lot, which represented a 67% discount to the reference tariff of 45 €/MWh and a world record, beating the previous low of around 15.8 €/MWh set this summer in Brazil. The awards highlighted strong competition for grid connections in the country and also hinted at the expectations of market participants that once 15-year the fixed price contracts expire, earnings in the wholesale market would provide sufficient revenue stream for profitable long-term operation of the generation assets.

**Figure 31 – Monthly electricity exchange traded volumes and average day-ahead prices in the Iberian Peninsula**

![Figure 31](image_url)

Source: Platts, OMEL, DGEG

- **Figure 32** displays the evolution of the weekly electricity generation mix in Spain during the third quarter of 2019, as well as during the same period of the previous year. The combined share of renewable electricity sources (hydro, wind, solar and biomass) reached 31.5% on average throughout the period, 2.5 percentage points down compared to Q3 2018 on the back of a 40% fall in hydro generation. The share of wind-powered output in Q3 2019, on the other hand, rose from 13% to 15%, while the share of solar increased from 7.5% to 8% year-on-year.

- The combined share of coal and gas in the mix went up from 41% in Q3 2018 to 43% during Q3 2019. This was driven by a significant boost in gas-fired generation which not only displaced coal but also stepped in to make up for missing hydro output and increased its share from 20% to 41% year-on-year. Coal plants, in contrast, suffered under adverse market conditions and saw their share reduced from 19% to 3% year-on-year as coal-to-gas switching intensified (see **Figure 13**). The share of nuclear energy in Spain’s mix, at 24%, was unchanged compared to Q3 2018. The total generation in the reference quarter rose by 4% year-on-year on the back of higher gas-fired and renewable output.
Figure 32 – Weekly evolution of the electricity generation mix in Spain in Q3 of 2018 and 2019

Source: ENTSO-E

- **Figure 33** shows average weekly electricity flows between France and Spain and price differentials between the two bidding zones. The average premium of Spanish day-ahead prices over their French peers averaged 10.9 €/MWh in the reference period, up 22% from Q3 2018, as rising carbon and fuel prices penalized the relatively more carbon-intensive Spanish generation. However, total net French exports to Spain decreased by 22% year-on-year to 2.5 TWh in Q3 2019, as the capacity of a 400 kV link (Cantegril-Argia-Hernani) between the two countries has been curtailed since spring. Several weaknesses were discovered on the line in July which required major repair works. The current schedule foresees maintenance to be completed in 2019. Spain and France are connected through five high-voltage power lines of combined 2.8 GW capacity.

- Bilateral trade with Morocco in Q3 2019 developed in Spain’s favour, as Morocco became net importer of Spanish electricity in August and September. Throughout the whole reference quarter, Spanish net exports to Morocco reached 60 GWh.

Figure 33 – Weekly flows between France and Spain and price differentials between them

Source: ENTSO-E, OMEL, Platts
3.6 Central Eastern Europe (Czechia, Hungary, Poland, Romania, Slovakia, Slovenia)

- **Figure 34** shows that average monthly prices for baseload power in Central Eastern Europe have followed a similar trajectory as other European regions at the beginning of the reference quarter, rising by 19% month-on-month in July to 52 €/MWh amidst higher CO2 and fuel prices, a few unexpected plant outages and import capacity reductions. Contrary to developments in most other regions however, baseload contracts in Central Eastern Europe continued to rise in August (to 54 €/MWh), as maintenance on vital interconnectors, temperature-related plant outages and weak hydro generation in the Balkans weighed on the region. The supply-side pressures only eased in September as milder temperatures put a damper on demand, import capacities and nuclear units became more available and wind increased its presence in the Polish mix. The monthly average peakload contracts in the region followed their baseload peers, keeping their premium at around 5 €/MWh throughout the reference quarter.

- When compared to the previous Q3, the average baseload price in the reference quarter fell by 13% to 52.7 €/MWh. Compared to Q2 2019, however, the average price in the reference quarter increased by 18%. That was the highest quarter-to-quarter increase of all the regions under observation.

- Hungary announced in September that it plans to phase out coal-fired power generation by 2030. Most of that comes from 950 MW lignite-fired Mátra Power Plant which in the first three quarters of this year covered around 9% of domestic consumption.

- Due to weak hydro generation and increased carbon prices, which put a strain on the local lignite fleet, the region became a significant importer of electricity in the reference quarter, recording a net deficit of 4.7 TWh. Poland alone increased its net imports from 0.9 TWh in Q3 2018 to 2.8 TWh in Q3 2019. Germany, Austria, Nord Pool markets and Ukraine were the largest sources of inflows.

Figure 34 – Monthly electricity exchange traded volumes and average day-ahead prices in Central Eastern Europe (CEE)

- **Figure 35** demonstrates relatively high volatility and wide differences in daily average baseload prices on the day-ahead market across the CEE region during the reference quarter. The lowest prices, usually between 30 and 50 €/MWh, were reported in the well-interconnected and well-supplied duo of Czechia and Slovakia. Baseload contracts in Poland, Hungary and Romania, which all had to rely on imports to various degrees, were on average sold at a 13-20 €/MWh premium to the Czech quotes. Slovenian day-ahead price were on average slightly lower than that, but prone to spikes in the second half of the quarter. The region coped well with the July heatwave, despite some plant outages and low hydro output in the Balkans. Rising solar generation in Hungary and Poland contributed to meeting increased cooling demand. Polish prices reached their highest levels in August, often dwelling above 60 €/MWh, as maintenance on the 600 MW link to Sweden significantly restricted imports of cheaper power from Scandinavia. Several price spikes rocked the markets in Hungary, Romania and Slovenia at the end of August and the beginning of September, with daily averages approaching or breaching 100 €/MWh. The events were triggered by temperature-driven demand peaks which collided with unplanned outages at the Paks nuclear plant and last-minute import restrictions in Hungary, coupled with weak wind generation in Romania and low run-of-river output across the Balkans (Slovenia, Croatia, Bulgaria, Romania, Serbia).
Figure 35 – Daily average power prices on the day-ahead market in the CEE region

![Power prices graph]

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

- Figure 36 compares the weekly evolution of the combined electricity generation mix of in the CEE region (excluding Poland) between the reference quarter and the quarter a year before. Nuclear generation constituted the most important pillar of the power sector in the sub-region, accounting for 38% of the total generation volume in Q3 2019 (second only to France and Belgium), up from 37% a year before. The combined share of lignite and coal in the reference quarter fell from 15% to 14% year-on-year, while gas managed to increase its share from 10% to 14% year-on-year, demonstrating measurable coal-to-gas switching lead by Czechia and Hungary (see Figure 13). Renewable energy sources (wind, solar, hydro and biomass) accounted for 21% of the total electricity production in the reference quarter, down from 22% in Q3 2018 on the back of poor hydro generation in Bulgaria and Romania. 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 stood at 78% in the reference quarter (compared to 82% in Q3 2018), while renewables increased their share from 11% to 14% year-on-year thanks to new wind and solar additions. Installed solar PV capacity in the country doubled in the first three quarters of the year, approaching 1 GW in September.

Figure 36 – Weekly evolution of the electricity generation mix in the CEE region (excluding Poland) in Q3 of 2018 and 2019

![Generation mix graph]

Source: ENTSO-E
3.7 South Eastern Europe (Bulgaria, Croatia, Greece and Serbia)

- Figure 37 shows that the trade-weighted monthly average baseload prices in the SEE region stayed more or less stable throughout Q3 2019, moving around 60 €/MWh, as decreases in the Greece (by far the most liquid market) compensated for rising prices in Bulgaria, Croatia and Serbia. Peakload contracts, meanwhile, traded at an increasing premium over their baseload peers, reaching more than 2 €/MWh at the end of the reference quarter, which was in line with seasonal patterns.

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

- Day-ahead Greek electricity wholesale prices were on average 7-12 €/MWh higher than in neighbouring markets in Q3 2019, as shown in Figure 38. Increased CO₂ prices and relatively uncompetitive supply contracts continued to weighed down the output of Greek lignite plants (~2 TWh year-on-year), while their gas-fired competitors boosted generation by 1.2 TWh thanks to low input costs. Rising renewable output, most importantly from wind farms, helped keep prices in check despite increased cooling demand during hot summer days. Day-ahead baseload prices in the rest of the region displayed a relatively high level of convergence in Q3 2019, with a few price spikes puncturing the 100 €/MWh mark in Serbia and Croatia during periods of temperature-related demand peaks and low hydro and wind availability in the region (see Figure 35).

- The average Bulgarian baseload electricity price in Q3 2019 increased by 32% compared to the previous quarter to 54 €/MWh, on the back of high consumption (+4% year-on-year), low hydro output and worsening market conditions for local lignite-based generators. A similar story played out in Croatia where average quarterly baseload price went up by 28% quarter-to-quarter to 55 €/MWh. The average Serbian baseload price, meanwhile, rose by 30% quarter-to-quarter to 57 €/MWh.

- Bulgaria is traditionally a net exporter of electricity to the rest of the region, especially Greece. Low hydro output in the reference quarter caused net outflows from the country to tumble by 37% year-on-year to 1.7 TWh.

- In August, Greece commissioned a new subsea cable connecting mainland with the Peloponnesian peninsula, marking an important milestone in the grid expansion programme run by the local DSO. The interconnector will stabilize the electricity system in the western part of the country and should eventually link up with the island of Crete, Greece’s largest autonomous power grid. Crete and dozens of other island power systems have plenty of underutilized renewable capacity. Network limitations have led the grid operator to place caps on the capacity of installed wind and solar resources on these islands, with almost four fifths of that cap already filled.

- Bulgarian, Greek and Romanian TSOs have agreed in July to establish a Regional Coordination Centre (RCC) by the end of the year for calculating capacity and assessing regional generation adequacy. RCCs are required to calculate cross-zonal capacities based on data from TSOs and respecting operational security limits. Other tasks include creating common grid models or coordinating regional outage planning.
Figure 38 – Daily average power prices on the day-ahead market in Bulgaria, Croatia, Greece and Serbia

Source: IBEX, LAGIE, SEEPEX, CROPEX

- **Figure 39** displays the evolution of the weekly electricity generation mix in Greece, Bulgaria, Croatia and Serbia during the third quarter of 2019, as well as during the same period of the previous year. As visible from the chart, lignite formed the basis of power production in the SEE region in Q3 2019, representing 37% of the total generation volume (down from 41% a year ago). Gas managed to increase its share in the reference quarter from 14% to 18% year-on-year, mainly thanks to intensive lignite-to-gas switching in Greece (see **Figure 13**). Nuclear generation saw its share rising from 11% to 13% on the back of higher output from Kozloduy Power Plant in Bulgaria. The share of renewable energy sources suffered a fall from 30% in 3Q 2018 to 28% in the reference quarter on the back of weak hydro generation in Bulgaria (~50% year-on-year), Croatia (~33% y-o-y) and Serbia (~20% y-o-y). The combined wind and solar generation, however, recorded a 12% year-on-year rise thanks mainly to higher wind output in Greece.

- In September, Greece announced a phase-out of coal generation by 2028 at the latest. The country has over 4 GW of lignite-based capacity which in the first three quarters of this year provided 22% of the total Greek power generation (down from 29% in 1-3Q 2018).

Figure 39 – Weekly evolution of the electricity generation mix in the SEE region in Q3 of 2018 and 2019

Source: ENTSO-E, Eurostat
4 Focus on corporate PPAs and residential PV

4.1 Corporate PPAs in Europe

- **Figures 40 and 41** report on the developments in the market of corporate renewable power purchase agreements (PPAs). These are long-term contractual agreements between generators and consumers (in this case corporate actors) to purchase and sell electricity produced by a renewable asset (existing or prospective) at a fixed price. By setting the offtake price for a long period in advance, PPAs offer renewable energy developers stable and predictable revenue streams and insurance against market prices swings, therefore incentivizing the investment in new renewable capacities without the necessity of public subsidy. This allows renewable generators to participate in the market without the distortive effects of government support schemes and also has a positive impact in the fiscal sphere. Thanks to their ability to insure future revenues, PPAs are also instrumental in obtaining competitive long-term project financing. Corporations can, in turn, gain economic advantages from signing a PPA, as it provides a certain amount of energy at a fixed cost, hedging the offtaker against possible future price increases. Secondly, PPAs allow corporations to meet their carbon reduction targets. Over 200 companies have committed to source all their electricity needs from renewable generation assets in the shortest possible time (by 2050 at latest) as part of the RE100 initiative; more than half of these are headquartered in Europe. PPAs also stimulate further development of energy markets. As a result of the increased demand for long term hedging of renewable energy assets’ production, major power exchanges are contemplating whether to extend their power futures horizon to 10 years ahead, so that PPA price risk could be better managed.

- **Figure 40** maps the evolution of the renewable capacity contracted via corporate PPAs announced and signed in previous years and in the first three quarters of 2019 in Europe. It also distinguishes the type of used technology. With the exception of 2017, the total annual contracted volumes increased in each of the previous years, reaching 2.3 GW in 2018. As of September this year, corporate offtakers were on track to surpass that result, having secured 1.8 GW (or about 81% of last year’s figure) from January to September. From the technological perspective, onshore wind installations are the most widely contracted, but offshore wind farms and solar parks gained market share this year, representing 17% and 26% of total contracted capacity respectively. Numbers of signed agreements have been fluctuating from year to year, showing that the market is still in its infancy and that it is driven by relatively few actors. However, the general trend of increasing contracted volumes and growing number of European countries involved (from 3 countries in 2013 to 13 this year so far) point to the fact that renewable energy can be price-competitive compared to the wholesale market, an important milestone in and of itself.

**Figure 40 – Evolution of the numbers and capacity of signed corporate PPAs in Europe**

- **Figure 41** shows that the Nordic countries are leaders in corporate PPAs signed this year both in terms of contracted capacity and the total number of agreements. Sweden, Denmark, Finland and Norway combined account for 56% of MWs contracted and 14 out of 32 deals concluded. Scandinavia’s dominance stems from a mixture of factors: good availability of wind and water resources, stable and favourable regulatory framework, and locally situated corporate actors with both high demand for energy and sustainability targets. Generally cooler temperatures, for instance, make the region a sought-after location for building data centres by techno-
logical companies. In contrast, in Southern Europe (Spain, Italy, Portugal) where very suitable conditions for subsidy-free solar generation exist, the large majority of contracts are signed by utility off-takers (as so-called utility PPAs) who are better able to handle associated risks (operational, pricing, weather-related) and then re-sell the electricity to final consumers. For the financing institutions, utilities also often represent a more desirable counterparty in terms of credit risk. The relatively low number of corporate PPAs in Germany reflects the fact that local developers have little incentive to sign them as long as the current robust government support schemes are in place. However, the upcoming expiry of 20-year feed-in tariffs for generation assets installed at the beginning of the century means that PPAs could be used to secure revenues for the remaining lifespan of these assets. That was the case with the one transaction announced in Germany this year. In the UK, government support is currently available mainly for offshore wind, which makes PPAs an attractive alternative for developers of onshore wind and solar PV projects. Large companies in Ireland have a legal obligation to report what proportion of the energy they consume is renewable and similar requirements are in place for issuing planning permits for new data centres, increasing the motivation of corporations to enter into PPAs.

- The off-taker spectrum is diverse, but dominated by technology companies which accounted for two thirds of capacity contracted in the first three quarters this year. Other parties on the demand side include representatives from heavy and chemical industry, consumer goods producers and railway operators.

Figure 41 – Country-by-country overview of corporate PPAs signed during 1Q-3Q/2019 in Europe

4.2 Residential PV in EU: tour d’horizon

- Rapid investment cost reductions coupled with Member State’s support schemes and rising retail electricity prices steadily increase the economic attractiveness of residential solar photovoltaic installations. In several markets (Germany, Belgium, Netherlands, Poland, Austria or Finland for instance) household activity is the driving force behind the expansion of the local solar capacity.

- Government support policies and regulations have been key to residential PV deployment, usually targeting two main areas: a) lowering investment costs via grants, rebates, tax credits or exemptions and b) stimulating self-consumption and sale of electricity to the grid via feed-in tariffs, net-metering or export tariffs.

- The oldest mechanism designed to incentivise the deployment of rooftop PV installations are feed-in tariffs (FiTs) under which homeowners are compensated at a fixed rate per kWh guaranteed for an extended period, thereby providing long-term price and offtake assurance and a relatively clear payback time. In most cases all PV generation is deemed to be sold to the utility, regardless of whether it is self-consumed or exported to the grid (under a so-called buy-all, sell-all tariff). Policymakers adopting these types of support schemes face the difficulty of setting (and timely updating) the right FIT which would stimulate enough interest and at the same time not lead to excessive fiscal outlays. Germany, which was an early mover introducing the mechanism in 2004, initially updated FiTs annually, but as it became clear that technology costs were dropping quicker than anticipated, a more rapid tariff reduction schedule was adopted in order to avoid overcompensation. Soon after that the FiT dropped below the level of residential retail rates which started to incentivize self-consumption. Most new systems installed in the country are now therefore configured to receive FIT only for exports to the grid. France has a similar mechanism, but the FiT recalibrates based on the amount of new capacity for which connection requests were received in the previous three-month period. As retail electricity prices in the country are comparatively low, the buy-all, sell-all model is still the most prevalent.
Italy and the UK used to have similar schemes but abandoned them in favour of export tariffs. Under these mechanisms, PV owners generate electricity for self-consumption and sell excess volumes to the utility. Accounting is usually done in real time (at hourly or half-hourly intervals). The export tariff is typically lower than retail electricity prices and can be adjusted over time, affecting both new and existing systems. A public authority could be in charge of setting the rate or it could be left up to the retailer. In Italy, the remuneration for excess generation amounts to approximately half the retail rate, which incentivizes households to optimize their daily demand profile and procure battery storage solutions in addition to PV panels. The government also provides income tax credits to PV owners. In the UK, electricity suppliers themselves set export tariffs with no price floor and no other policy support embedded. One supplier offers around 6.5 eurocent/kWh flat export tariff (about one quarter of the retail rate for a median household), which translates to a 15-year payback time, assuming 30% self-consumption rate. That compares with payback times under 7 years which can be achieved in Belgium under the local net metering scheme. Spain recently revised its self-consumption regulatory framework, setting the remuneration for excess electricity at retail rates and simplifying the registration process for applicants.

Net metering represents the most common support model. In it, PV owners use the distribution network as if it were a battery. Self-consumption is treated as in the previous model, but electricity that is exported to the network is not remunerated in real-time and instead awarded with credits that can be used to offset consumption from the network at a later time or date. The longer the period over which the credits can be redeemed, the more economically attractive the scheme is for households. The level of remuneration of the exported electricity varies from scheme to scheme. Member States with a net metering scheme include Belgium, Cyprus, Finland, Hungary, Latvia, the Netherlands, Poland or Romania.

Governments have also introduced special charges on households with rooftop PV in an attempt to account for the increased network costs associated with distributed generation and to recover some of the fixed costs of serving a customer that are bypassed through self-supply. In Flanders, households are obliged to pay around 100 euros per 1 kW of installed capacity a year for using the distribution network.

An important feature of several market are group purchases in which PV customers in a given area aggregate their demand through a commercial or non-profit organisation, which then auctions the portfolio to solar installers, achieving economies of scale. This model results in very competitive prices for rooftop PV installations and contributes to relatively high PV penetration rates in the markets where group purchases are commonplace.

Self-consumption is highly relevant in the context of the drive towards greater consumer empowerment and engagement, and the realisation of Europe’s renewable energy targets. Legislative acts, such as the recast Renewable Energy Directive (EU 2018/2001) adopted recently as part of the Clean Energy for All Europeans package introduce definitions that formally recognise renewables self-consumers, jointly acting renewables self-consumers and renewable energy communities and give them the right to generate, including for own consumption, store and sell their excess production.

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6 Based on calculations by BloombergNEF.
5 Retail markets

5.1 Retail electricity markets in the EU

- Figures 42 and 43 display estimated retail prices in September 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 consumed).

- Smaller industrial consumers (band IB) were assessed to pay the highest prices in the UK (18.6 c€/kWh), Italy (18.3 c€/kWh) and Germany (18.1 c€/kWh), followed by Ireland and Cyprus (16.9 and 16.4 c€/kWh, respectively). The lowest prices in the same category were assessed to be in Sweden (8.1 c€/kWh) and Denmark (8.6 c€/kWh). The ratio of the largest to smallest reported price was above 2:1. On the other side of the consumer spectrum, industrial companies with large annual consumption (IF), including most energy intensive users, paid the highest prices in the United Kingdom (14.2 c€/kWh) followed by Cyprus (12.8 c€/kWh), Slovakia and Malta (both 9.9 c€/kWh). Luxembourg (5.7 c€/kWh) was assumed to have the lowest prices, followed by Sweden and Denmark. The ratio of the highest to lowest price for large industrial consumers was almost 4:1 for this consumer type. Compared to September 2018, the average assessed EU retail electricity prices for the IF band increased by 7.5% to 8.4 c€/kW

- In September 2019, Germany (29.2 c€/kWh) was assessed as having the highest electricity price for large household consumers (band DD), followed by Belgium (24.8 c€/kWh), and with Denmark (22.1 c€/kWh) and Italy (22.1 c€/kWh) jostling for the third place. The lowest price for big households was calculated for Bulgaria (10.2 c€/kWh) and Hungary (10.9 c€/kWh). In the case of the small households, Germany was again evaluated as having the highest price (35.1 c€/kWh), followed by Ireland and Denmark, while Bulgaria and Hungary found themselves again at the other side of the price spectrum. Household electricity prices are 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 relatively high, around 3:1.

Figure 42 – Industrial electricity prices, September 2019 – without VAT and recoverable taxes

Source: Eurostat, DG ENE
Figure 43 – Household electricity prices, September 2019 – all taxes included

Figure 44 and 45 display the convergence of retail prices across the EU over time, by depicting their standard deviation. End-user prices for all three levels of industrial consumption showed relatively stable dispersion levels throughout the reference quarter in comparison to Q2 2019, with the lowest level of divergence being measured for large industrial consumers and the highest one of smaller businesses. 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.

In line with the general trend this year, retail electricity prices for households showed growing convergence across all categories in the reference quarter. 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.

Source: Eurostat, DG ENER
• **Figures 46 and 47** 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 Q3 2019. In the case of household prices, Germany topped the list, followed by Denmark and Belgium. As 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 household price in the EU stayed without significant changes in the reference quarter compared to the situation in Q2 2019 and rose by 2% compared to the last month of Q3 2018. The largest year-on-year increases in the household category in September were assessed in the Netherlands and the UK (both +16%), Czechia (+15%) and Lithuania (+14%). The biggest year-on-year falls were estimated for Spain (-19%), Denmark (-13%) and Cyprus (-11%).

• In the case of mid-sized industrial consumers, Denmark was assessed to have the most competitive price in Q3 2019, moving in front of Sweden and with Finland taking the third place. Meanwhile, the UK, Italy and Germany stood at the other end of the spectrum. The average retail price for industrials in the EU in the reference period, at 12.43 eurocents/kWh, was estimated unchanged compared to Q2 2019 and up 8.0% compared to Q3 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 the increased attention to cost competitiveness paid by the industry.

Source: Eurostat, DG ENER

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**Figure 45 – Standard deviation of retail electricity prices in the EU Member States for household consumers**
Figure 46– Household Electricity Prices, third quarter of 2019

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices.
Figure 47 – Industrial Electricity Prices, third quarter of 2019

Source: Data computed from Eurostat half-yearly retail electricity prices and consumer price indices
• **Figure 48** 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 September 2019, the highest prices were observed in Berlin and Copenhagen (32.3 and 29.6 c€/kWh, respectively) where energy taxes accounted for approximately a third of the final bill. The lowest prices of EU Member States were recorded in Budapest and Sofia (11.4 c€/kWh and 11.6 c€/kWh, respectively). This corresponds to the Eurostat data analysed in **Figure 43.** Non-Member States in Europe’s east tend to have lower prices. Thus, electricity for an average household in Belgrade is four times cheaper than for one in Copenhagen.

• The highest levels of the energy component were reported from Nicosia, Dublin and London (11-15 c€/kWh), cities surrounded by wholesale markets with higher prices compared to the EU average. The lowest levels of the energy component (4.5-6 c€/kWh) were recorded in the capitals of countries with stronger forms of price regulation (Budapest, Bucharest, Bratislava) or with a high degree of renewable production (Copenhagen, Stockholm). The EU average in the reference quarter for the energy component was 7.9 c€/kWh (up 7% from September 2018).

• The highest network charges were recorded in Lisbon (10.2 c€/kWh) where, despite a significant cut compared to last year, they accounted for 45% of the total price and were measurably higher than the energy component. The lowest network fees were collected in Valletta (1.6 c€/kWh) and Sofia (2.7 c€/kWh). The EU average in the reference quarter was 5.3 c€/kWh (down 2% from September 2018).

• Apart from Berlin and Copenhagen (10-11 c€/kWh), the highest energy taxes were paid by households in Madrid and Rome (5.5-7.5 c€/kWh), Valletta, Sofia and Budapest stood at the other end of the range, with zero energy taxes collected by the local authorities.

**Figure 48 – The Household Energy Price Index (HEPI) in European capital cities in Eurocents per kWh, September 2019**

Source: Vaasaett

• Compared to the same month of the previous year, the largest price increases in September 2019 were observed in Kiev (+19%), followed by Vilnius (+15%) and Amsterdam (+16%). As shown in **Figure 49,** in Kiev and Vilnius the energy component was the biggest contributor to rising prices, while in the case of the Dutch capital growing energy taxes were the main driver behind the retail price movement. Nine EU capitals reported prices lower than in the same month of the previous year, with Zagreb (-9%), Copenhagen (-7%) and Madrid (-5%) posting the largest drops. The price fall in the Croatian capital was caused exclusively by a lowered VAT rate, whereas in the Spanish capital the decreasing energy component was the driving force. Retail prices in the Danish capital were pushed down by a substantial cut in energy taxes which was accompanied by lower network charges and a decreased VAT component.

• The energy component decreased in seven EU capitals from September 2018 to September 2019, with the biggest drops in absolute terms registered in Madrid, Stockholm and Brussels. Network charges remained broadly stable across the EU, with the exception of Portugal where a significant decrease drove the total retail price lower in spite of a more expensive energy component. Paris, on the other hand, experienced a substantial increase in network fees. Measurable increases in network charges were also reported from Vilnius and Sofia. Energy taxes decreased materially in Denmark, Ireland and Greece, while going up in Italy, the Netherlands, the UK and Luxembourg.
5.2 International comparison of retail electricity prices

- **Figure 50** displays industrial retail prices paid by consumers in the EU and in its major trading partners. Prices include VAT (with the exception of US prices) and other recoverable taxes for the purpose of comparability.

- Prices in the EU remained stable in Q3 2019, rising by less than 1% compared to the previous quarter. Other regions saw more dynamic developments, with South Korea registering a 17% price rise quarter-to-quarter and the US industrial end-user prices growing by 9% quarter-to-quarter in euro terms. Power consumption in the reference quarter became more expensive also for industrial companies in Brazil, where prices increased by 6% compared to Q2 2019. Only the Chinese retail were an exception, continuing in their downward trend and declining by 6% in Q3 2019 compared to the previous quarter.

- China expanded the reform of its power sector in the second half of the year and replaced the fixed on-grid tariff which still applies to approximately 60% of its coal power generation with floating adjustments. The new mechanism should allow for a gradual deregulation of all generation in the country and contribute to lower power costs for consumers.
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 (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 devi-
ation 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.