

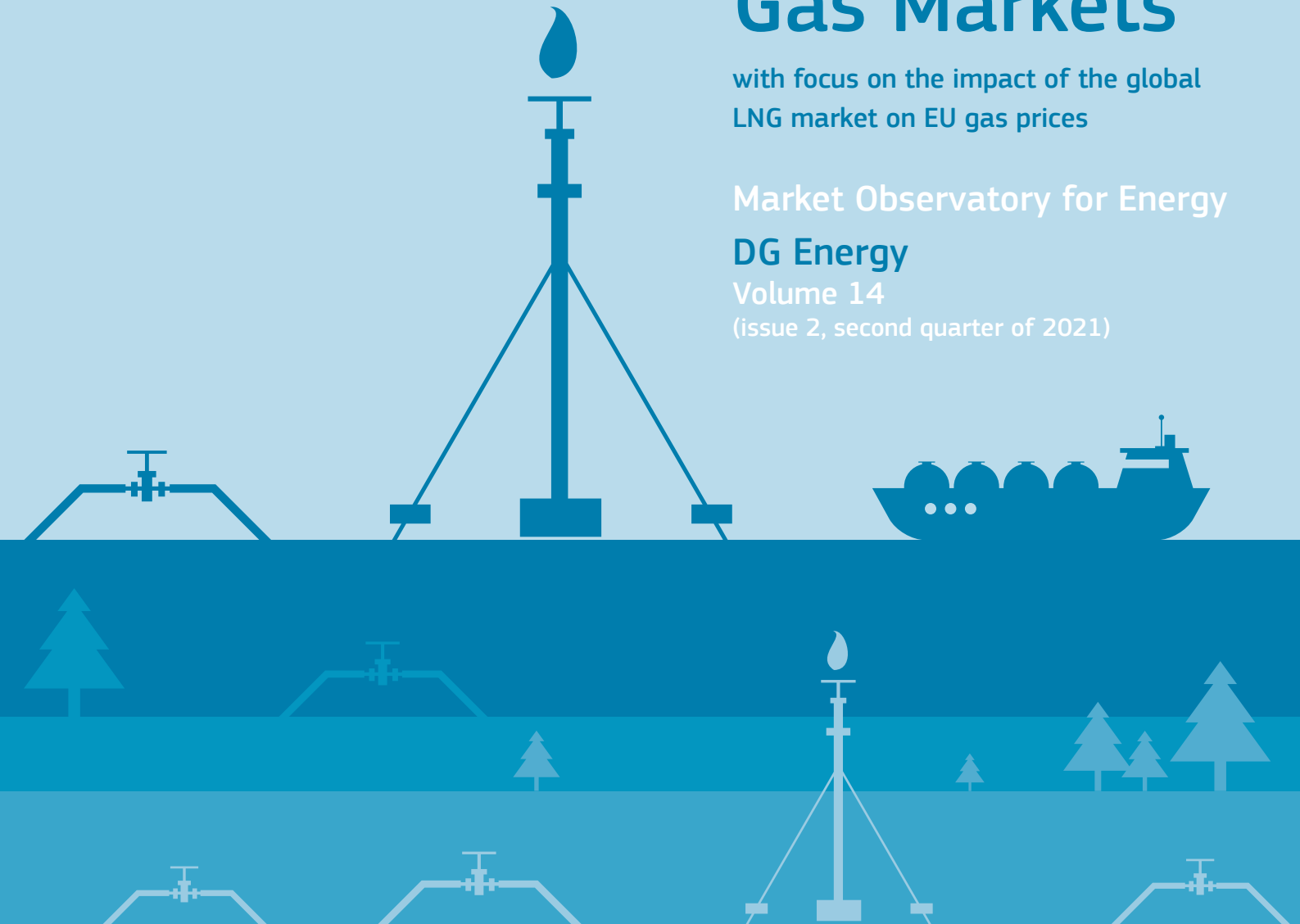


Quarterly Report

on European Gas Markets

with focus on the impact of the global
LNG market on EU gas prices

Market Observatory for Energy
DG Energy
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HIGHLIGHTS OF THE REPORT

- **Wholesale gas prices in Europe underwent a significant increase in the second quarter of 2021, setting off from 19 €/MWh at the beginning of April and finishing the month of June at 35 €/MWh. During the summer months and early autumn, the average spot wholesale price continued to soar and reached even 70-75€/MWh in September 2021, never seen since the beginning of trade on the European gas hubs. Meanwhile, carbon prices, also impacting wholesale gas market, continued to increase in Q2 2021, and coal and oil prices were up as well, showing the generally positive mood on energy commodity markets.**
- Behind the significant increase in the EU wholesale gas prices, there can be found several reasons, impacting either the supply or demand side of the market. **Demand for LNG was continuously increasing in the Asian markets**, which, coupled with the supply constraints at some big LNG producers countries' liquefaction sites (e.g. deferred maintenance), coupled with increasing international freight transport costs, also impacting LNG cargoes, resulted in increasing wholesale gas prices in each region. For Europe, it meant fierce competition for LNG and given an existing premium of the Asian gas markets to Europe, less cargo availability and increasing prices. Over Q2 2021 and beyond in the following quarter, Asian wholesale gas benchmarks became indicative for the TTF in Europe. (See more on global factors, impacting LNG prices in the Focus on chapter of the current report).

EU LNG imports were slightly up, by 1% year-on-year in Q2 2021, amounting to 24 bcm, though imports were up in April and June, but down in May year-on-year, showing that, owing to the aforementioned reasons, no clear and solid rebound could be observed throughout Q2 2021, after the significant fall in the previous quarter. In Q2 2021, France had the biggest LNG imports in the EU (5.8 bcm), followed by Spain (5.2 bcm), and Italy (3.3 bcm). The United States were the largest LNG source for the EU, ensuring 7.4 bcm of imports, followed by Russia (5.1 bcm) and Qatar (4.4 bcm). China overtook Japan as the biggest LNG market in the world, importing 28 bcm of LNG in Q2 2021, followed by the EU (24 bcm) and Japan (22 bcm – second biggest market as single country).

- **Low gas storage levels in the EU also significantly contributed to rise in wholesale gas prices.** At the end of June 2021, the average storage filling rate was 47.5% in the EU on average, which was the lowest over the last decade at this time of the year and 33 percentage points lower than at the end of June 2020. The main reason behind sluggish storage refilling was a series of cold snaps during April and May 2021 in most of the EU, resulting in switching back from storage injection to withdrawal several times, and lower than expected gas inflows from important sources, such as Norway. Increasing gap of refilling rates ahead in Q2 2021 and in the following quarter put an upward pressure on spot gas prices, and elevated injection needs ahead of the winter heating season increased supply tightness of the gas market.
- **EU net gas imports rose by 7% year-on-year** (by 6.2 bcm) in Q2 2021. Russian pipeline supplies covered 42% of extra-EU net gas imports, whereas the share of LNG imports altogether amounted to 23%. The share of Norwegian pipeline gas fell below 20% in Q2 2021 (six year low), principally owing to the gas infrastructure maintenance works in Norway, brought forward to the second quarter of the year. Pipeline imports from Algeria more than tripled year-on-year, and covered 11% of the total extra-EU gas imports in Q2 2021, as oil-indexed price contracts were increasingly competitive vis-à-vis soaring gas hub prices. The Trans Adriatic Pipeline (TAP) ensured 1.9% of the total extra-EU gas imports, whereas the share of Libya was less than 1% in Q2 2021. Net gas imports in the EU amounted to 78.5 bcm in Q2 2021, and in the first half of 2021 they reached 180 bcm (up from 166 bcm in the first half of 2020).
- **Nord Stream remained the most important supply route of Russian pipeline gas to the EU in Q2 2021**, having a share of 40% in the Russian pipeline imports (15 bcm of gas transit), the Belarus transit came to the second place, with a share of 27%, followed by the Ukrainian transit (26%), both with 10 bcm of gas transit. The share of the Turk Stream was 7%, with slightly less than 3 bcm of gas transit. In Q2 2021 and over the summer, Gazprom booked less than expected (and/or no additional) capacities, mainly through the Ukrainian and Yamal pipelines, which was interpreted by some market actors as a trial to convince European partners for the need of swift finalisation of the new Nord Stream 2 pipeline.
- **EU gas consumption in Q2 2021 was up by 19%** (13.5 bcm) year-on-year, amounting to 84.5 bcm. The high percentage increase was principally owing to low gas consumption in Q2 2020, with the onset of Covid-related restrictions that time, however, cold weather in Q2 2021, increase of gas use in electricity generation (up by 9.3% - 9.9 TWh), and general economic rebound also supported the increasing demand for gas. EU GDP in Q1 2021 was up by 2.7% compared to the previous quarter, signalling an ongoing economic recovery after lifting Covid-related restrictions in many sectors of the economy. Gas consumption amounted to 223 bcm in the first half of 2021, increasing by 11% (23 bcm) compared to the same period of 2020.
- **Indigenous gas production in the EU, amounting to 12.7 bcm in Q2 2021, was down by 8%** (1.7 bcm) compared to Q2 2020, and reached the second lowest quarterly production over the last decade. In Q2 2021, the Netherlands produced 5.9 bcm of gas (-10% year-on-year), whereas Romania produced 2.2 bcm (+10%). Gas production in the EU amounted to 26.7 bcm in the first half of 2021, down from 29.4 bcm in the first half of 2020.
- **Gas traded volumes on the European hubs fell by 4% (by 607 TWh)** in Q2 2021 year-on-year, after the decrease of 13% in the previous quarter. Even amid increasing gas consumption and imports, traded volumes on the most liquid European hubs were down, as trading volumes were mainly driven by near-curve contracts (spot and month-ahead), supported by increasing need for gas in power generation, whereas trade on the far end of the curve decreased further.

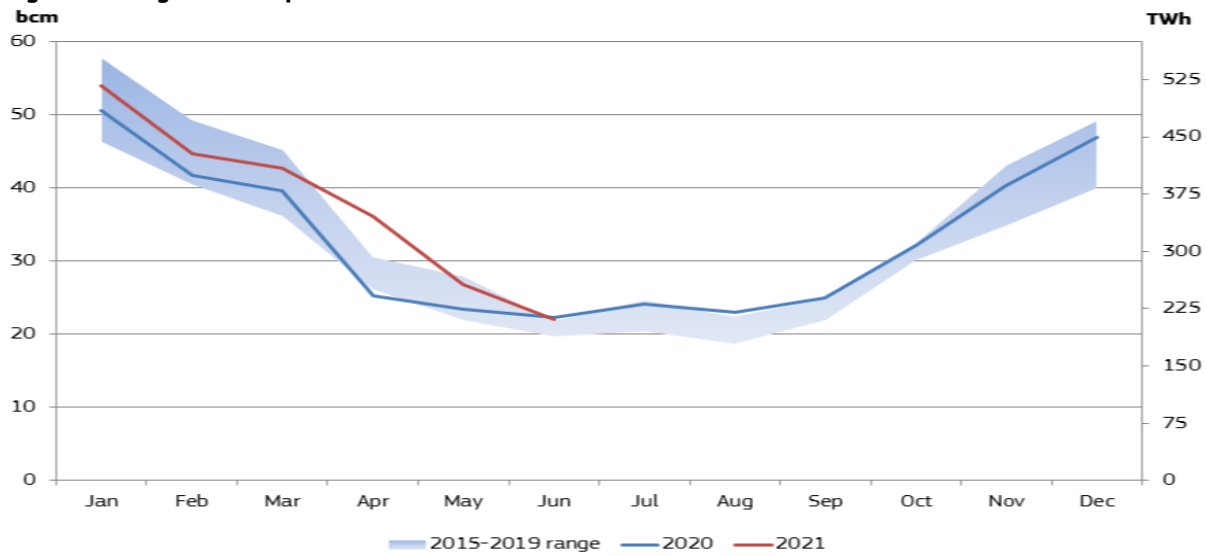
- **Spot prices on the European gas hubs in Q2 2021**, were up by around 30-40% compared to the first quarter of 2021, being in a quarterly range of 24-26 €/MWh, whereas they were three to five times higher than in Q2 2020, when prices fell to historic lows. Even compared to the pre-crisis Q2 2019 quarter, spot prices rose by 50-110%. The discount of forward contracts to the spot market increased over Q2 2021, in the case of the year-ahead-to-spot discount reaching 9 €/MWh by the end of June 2021, implying that the market anticipates a correction in high spot prices in the following year.
- **Retail gas prices for household customers showed an increase of 7.5% year-on-year in Q2 2021**. With the exception of three countries, gas prices for households in European capital cities were higher in August 2021 compared to the same month of 2020, implying that recent price increases on wholesale gas markets was already perceivable in retail contracts. However, as wholesale gas prices have been rising further following Q2 2021, there is a high probability that retail prices will follow, and this will impact the energy bill of households and entail financial strain on utilities profits.
- **Hydrogen costs-based assessments** showed that in the Netherlands **production costs of hydrogen** (capital expenditure costs included) with alkaline electrolyser technology amounted to 138 €/MWh in March 2021, whereas with polymer electrolyte fuel cells (PEM) the cost was assessed to 172 €/MWh, and with steam methane forming at around 51 €/MWh, showing that recent steep increase in wholesale gas and electricity prices can also be tracked in hydrogen price assessments.

1. Gas market fundamentals

1.1 Consumption

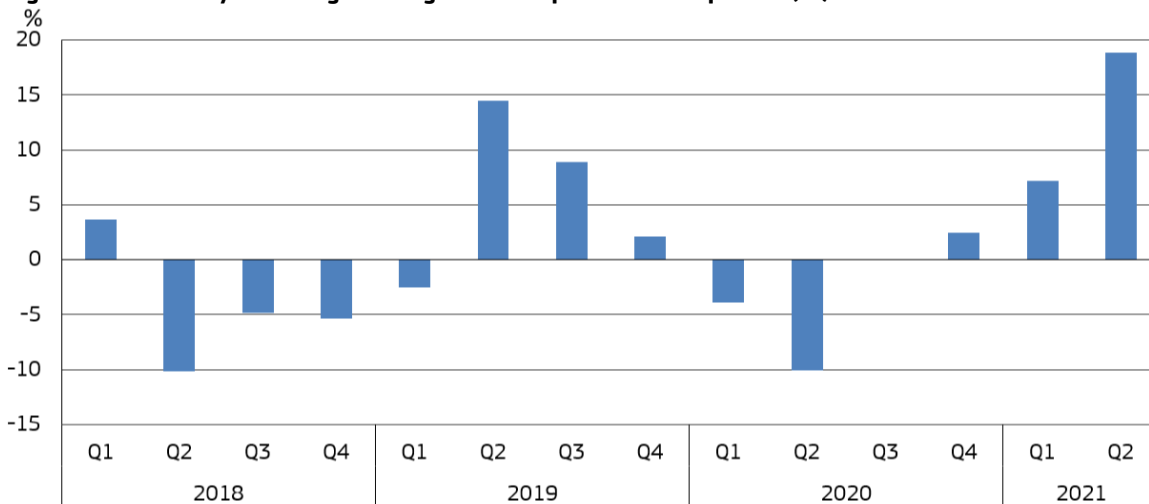
- EU gas consumption¹ in the second quarter of 2021 rose by 18.9% (13.5 bcm) in year-on-year comparison, after the increases in the fourth quarter of 2020 (2.5%) and in the first quarter of 2021 (7.2%). In absolute numbers, the quarterly gas consumption in Q2 2021 amounted to an estimated 84.9 bcm, up from 71.4 bcm in Q2 2020, but down from 141.2 bcm in Q1 2021, after the end of the heating season in the first three months of the year. Year-on-year increase in gas consumption in Q2 2021 was the highest in the last seven years, owing to very low consumption in Q2 2020 with the onset of Covid-19 related demand destruction in that period. In electricity generation, demand for gas rose by 9.3% year-on-year (increasing by 9.9 TWh). Weather across Europe was generally colder than usual in Q2 2021, increasing demand for gas for residential heating needs, and June 2021 was warmer in many countries, increasing cooling needs. As Figure 1 below shows, in the first quarter of 2021 gas consumption in the EU was higher (in April) and close (in May) to the upper range of the last five years. In first half of 2021, natural gas consumption in the EU amounted to 226 bcm, up by 11% (23 bcm) compared to the same period of 2020.

Figure 1 - EU gas consumption



Source: Eurostat, data as of 9 September 2021 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

Figure 2 - Year-on-year change in EU gas consumption in each quarter (%)

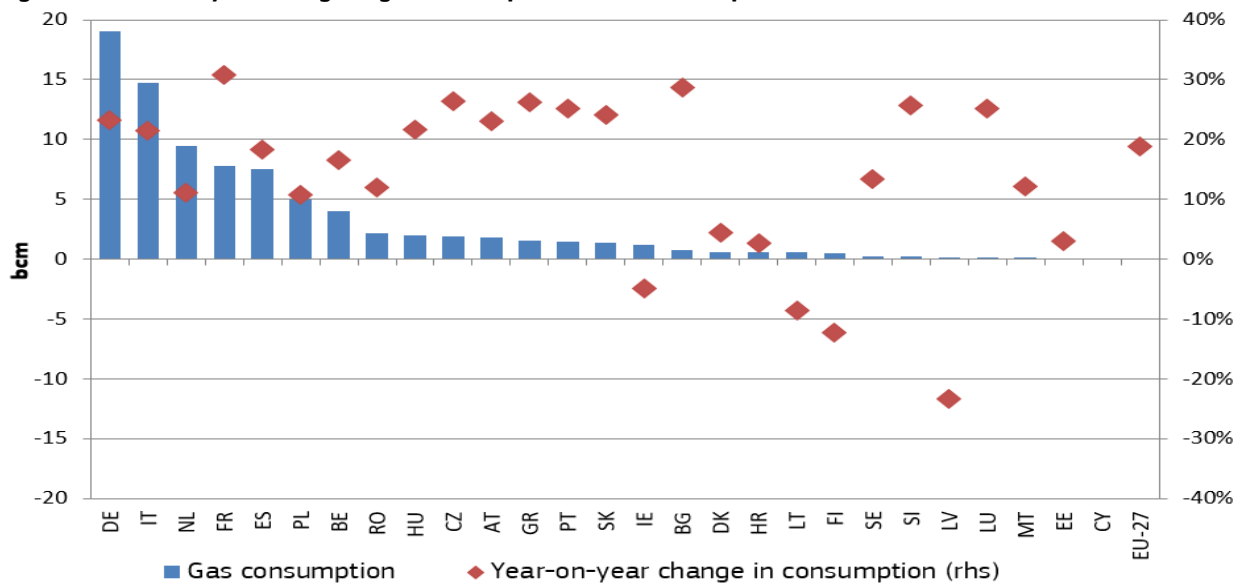


Source: Eurostat, data as of 9 September 2021 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

¹ EU aggregates, unless otherwise indicated, refer to EU-27, and in order to ensure comparability over time, values of earlier periods and year-on-year comparison indices also refer to EU aggregates without the United Kingdom. Therefore, in comparison to earlier editions, total EU aggregate numbers might differ in the current report.

- In the second quarter of 2021, gas consumption decreased only in four EU Member States year-on-year (in Latvia, by -23%, though by marginal quantity - 0.05 bcm, Finland, by 12% - 0.06 bcm, in Lithuania, by 9% - 0.06 bcm and in Ireland, by 5% - 0.06). In all the other 22 Member States (no data available for Cyprus) gas consumption was up in Q2 2021 year-on-year. Gas consumption, in order of percentage changes, rose by the most in France (by 31%, +1.8 bcm), in Bulgaria (by 29%, +0.2 bcm), and in Czechia and Greece, in both by 26% and respectively by 0.4 bcm and 0.3 bcm. On the top of France, among the five biggest gas consumer countries, consumption rose by 23% (+3.6 bcm) in Germany, by 21% (+2.6 bcm) in Italy, by 18% (+1.2 bcm) in Spain and by 11% (+0.9 bcm) in the Netherlands. In Q2 2021 there were twelve EU Member States where the year-on-year change in gas consumption was greater than 20% and another eight countries where gas consumption was up by more than 10%.
- In the first half of 2021, gas consumption was up by 15% in Germany (+7 bcm), in France by 13% (+2.7 bcm), in Italy it rose by 11% (+3.8 bcm), in the Netherlands it went up by 10% (+2.1 bcm) and in Spain by 7% (+1 bcm), in comparison to the first half of 2020.

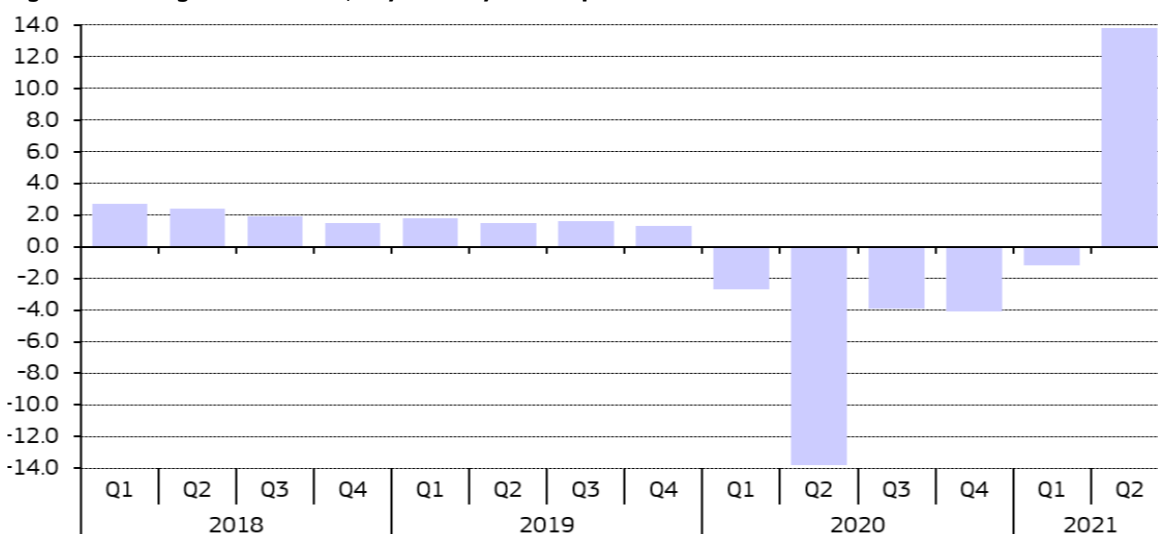
Figure 3 - Year-on-year change in gas consumption in the second quarter of 2021



Source: Eurostat, data as of 9 September 2021 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

- In the second quarter of 2021, GDP in the EU-27 was up by 13.8% in year-on-year comparison, principally owing to the poor base period performance in Q2 2020. Although the EU economy still could not get back to its pre-pandemic level, in Q2 2021 GDP was up by 2.1% quarter-on-quarter, which might also have contributed to the increase in natural gas consumption, as demand for gas rebounded in the industrial sectors.

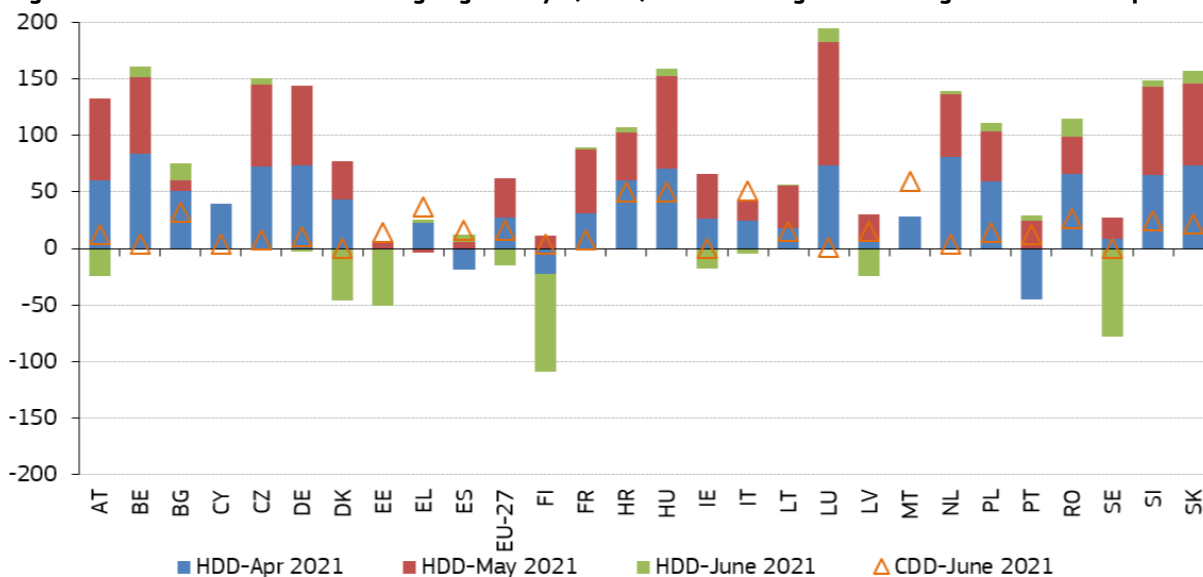
Figure 4 - Change in EU27 GDP, in year-on-year comparison (%)



Source: Eurostat, data as of 10 September 2021 from data series namq_10_gdp - Seasonally and calendar adjusted data

- Figure 5 shows the deviation of actual heating degree days (HDDs) and cooling degree days (CDDs) from the long-term average² in individual EU Member States in the second quarter of 2021. In the overall majority of the EU countries, April and May 2021 was colder than usual, implying an extension of the winter heating season for the residential sector, which translates into higher demand for gas and slower refilling of gas storages, still switching back to withdrawal mode many times. In countries where heating is largely based on electricity, more electricity had to be generated from natural gas. June 2021 was warmer than usual, mainly in the southern and eastern countries, which implied higher residential cooling needs and demand for gas in electricity generation.

Figure 5 - Deviation of actual heating degree days (HDDs) from the long-term average in the second quarter of 2021



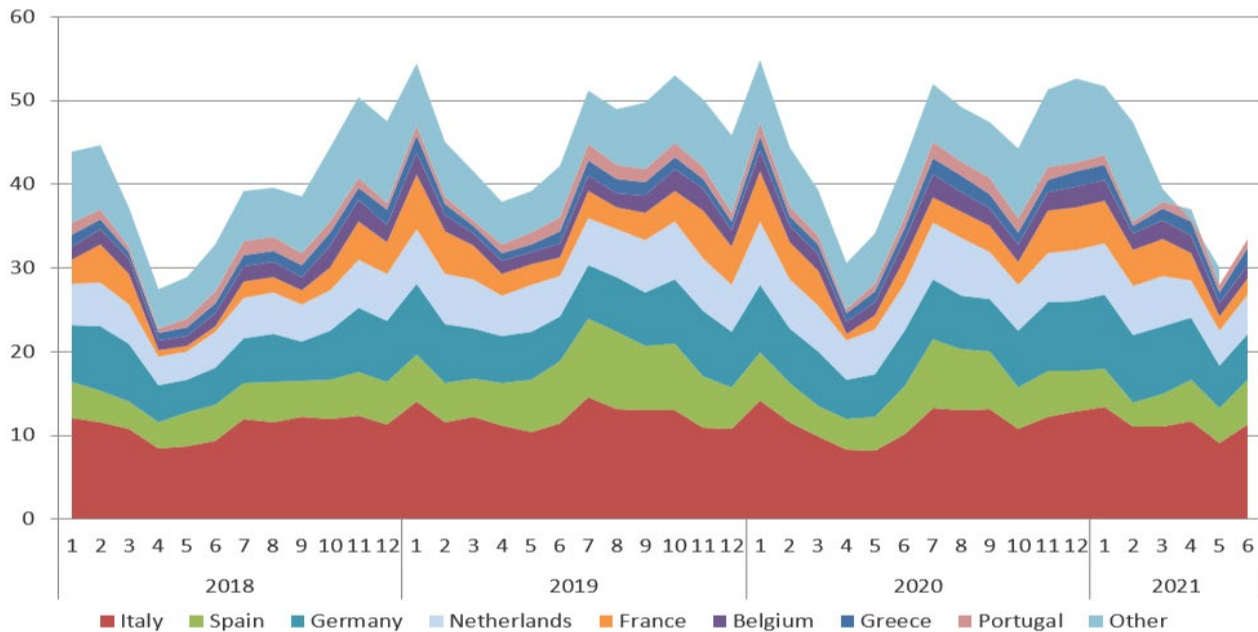
Source: Joint Research Centre (JRC), European Commission

- Based on data from ENTSO-E, gas-fired power generation increased by 9.3% in the second quarter of 2021 in the EU, compared to the same period of 2020. In absolute terms, electricity generated from gas was up by 9.9 TWh year-on-year, as Figure 6 shows. In Q2 2021 gas wholesale prices showed a significant increase, which was not favourable to generation costs and profitability of gas-fired generation. However, gas-fired power generation was up by 42% in April 2021 year-on-year, also due to low electricity generation in April 2020, which followed by a sharp downturn, as use of gas respectively decreased by 1% and 6% in May and June 2021, along with increasing gas and carbon prices.
- In year-on-year comparison the share of renewables in the EU power generation mix decreased slightly in Q2 2021. Wind, solar, biomass and hydro together represented around 41.5% of the EU power mix (down from 43.4% in Q2 2020). The share of gas remained practically unchanged year-on-year, and amounted to 18% in Q2 2021. The share of power generation from solid fuels rose slightly, from 10.6% to 12.5%³, as coal and lignite-fired generation together rose measurably, by 29% in Q2 2021 year-on-year. Electricity generation from nuclear rose by 11% in Q2 2021 year-on-year, and its share remained close to 25%. Carbon prices showed a measurable increase over the course of Q1 2021, rising from 42 €/MtCO_{2e} to 56€/MtCO_{2e} which, through increasing generation costs, did not contribute either to the competitiveness of fossil fuels in EU power generation. As gas prices rose even more sharply (from 19 €/MWh to 36 €/MWh) in Q2 2021, the profitability of gas-fired generation comparatively decreased vis-à-vis coal and lignite and hence solid fuel generation was up by 29% whereas gas fired generation rose only by 9% in Q2 2021, year-on-year.
- In Q2 2021, the amount of electricity generated from gas fell in the Netherlands by 14% in year-on-year comparison. At the same time, gas-fired generation rose by 23% in France, by 21% in Italy, and by 8% in Spain and Germany. Besides demand side factors, the share of gas was impacted by changes in the local power generation mixes. In the Netherlands, the decrease in gas-fired and nuclear generation was compensated by increasing solar, wind, biomass and hydro, and coal-fired generation also went up. In France, gas-fired generation went up, however, in year-on-year comparison nuclear showed a spectacular increase, whereas wind and solar also rose, in contrast to decreasing hydro. In Italy, gas-fired generation rose significantly, and with the exception of the small increase in biomass, all generation sources saw decreases. In Spain, rise in electricity generation from gas was accompanied by a similar decrease in hydro, whereas nuclear, solar, wind and biomass-fired generation all went up, along with a tiny increase in coal-fired generation. In Germany, increase in gas-fired and nuclear generation was accompanied with a robust upturn in coal and lignite use, whereas renewables did not show too big changes in Q2 2021, year-on-year.

² Long term average temperatures, heating and cooling degree days refer to the period between 1978 and 2018

³ See more information in Quarterly Report on the European Electricity Markets, Vol. 14, Issue 2

Figure 6 - Gas-fired power generation in the EU
TWh



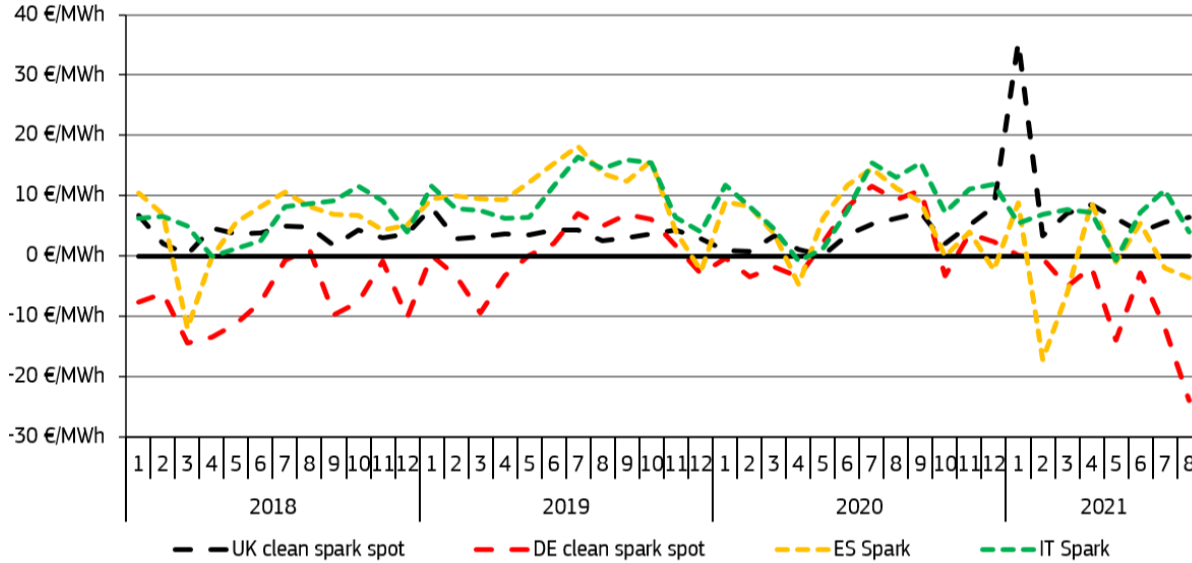
Source: Based on data from the ENTSO-E Transparency Platform and national data sources, data as of 18 September 2021

- Clean spark spreads – measuring the profitability of gas-fired generation by taking into account variable costs – reached respectively -6.2 €/MWh, 4.4 €/MWh and 4.6 €/MWh in Germany, Spain and Italy in Q2 2021, showing a mixed picture in comparison with the previous quarter, as in Germany and Italy spreads showed decreases (from -1.8 €/MWh and 6.6 €/MWh in Q1 2021, respectively), whereas in Spain they rose from -4.9 €/MWh observed in Q1 2021. This decrease in the clean spark spreads implied decreasing profitability of gas-fired generation⁴ in Germany and Italy (See Figure 7⁵). The impact of increase in gas prices and carbon prices in Q2 2021, compared to the previous quarter, was bigger than the increase in wholesale electricity prices in both countries, which resulted in decreasing spreads. In Spain however, electricity prices rose more sharply than gas and carbon, ensuring an improving profitability of gas-fired generation.
- In the United Kingdom, having relevance for the European gas market, clean spark spreads averaged at 6.2€/MWh in Q2 2021, down from 15.2 €/MWh in Q1 2021, however, high spreads in Q1 2021 were principally owing to the outstandingly high January spread – 36 €/MWh, when price spikes on the gas market resulted in extremely high wholesale electricity prices and high profitability of gas-fired generation. In April, May and June 2021 monthly UK clean spark spreads showed a slightly decreasing trend (from 8 €/MWh to 4 €/MWh), owing to carbon prices reaching successive record highs. Higher wholesale electricity prices were higher in the UK in comparison to the continental Europe ensured higher gas-fired profitability in the country. Electricity generated from gas was up by 41% in Q2 2021 year-on-year, and the share of gas-fired generation was 48% in the same period, as opposed to 39% in Q2 2020.

⁴ Assuming an average gas power plant efficiency, see more in the Glossary

⁵ Charts of clean spark spreads can also be found in the Quarterly Report of European Electricity Markets (Vol. 14, Issue 2). Data on the share of gas in electricity generation come from the database of ENTSO-E

Figure 7 - Clean spark spreads in Germany, Spain, Italy and the United Kingdom



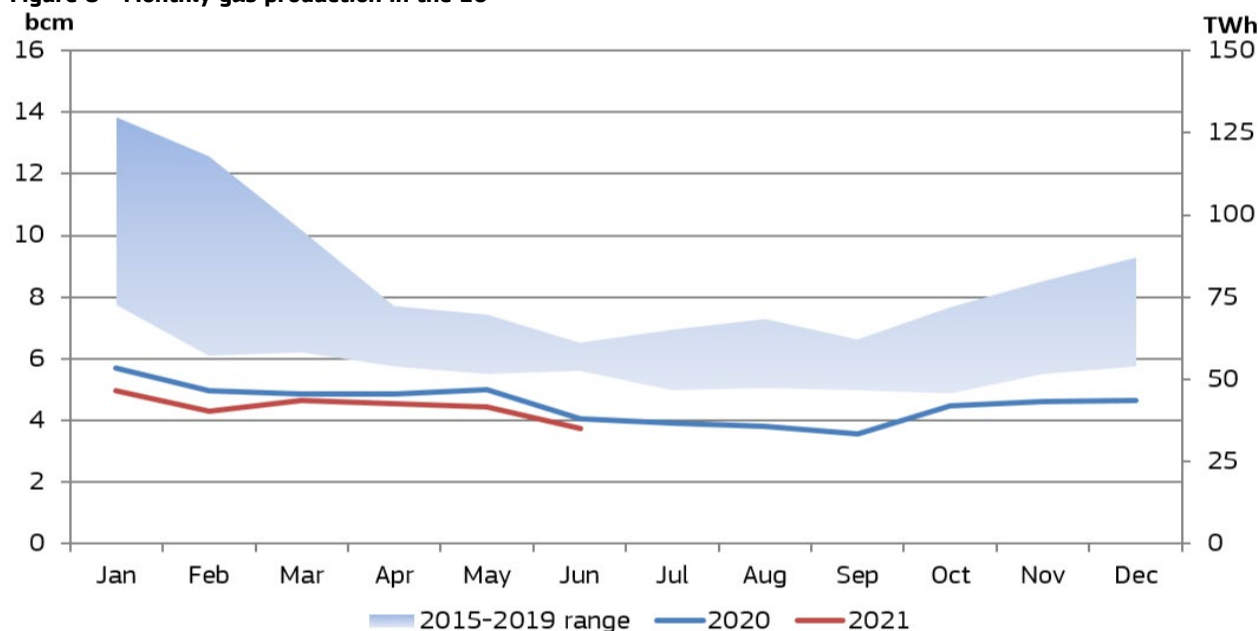
Source: Bloomberg

1.2 Production

- In the second quarter of 2021, EU gas production reached approximately 12.7 bcm⁶, 8% (1.2 bcm) less than in the same quarter of 2020 (See Figure 8). During the whole Q2 2021, similarly to the previous quarters, gas output was not only below the 2015-2019 range, but fell back year-on-year as well, reflecting the dwindling trend of gas production in the EU. Over the last seven years, total EU gas production in Q2 2021 was the second lowest quarterly figure (after the trough of Q3 2020 – 11.3 bcm).
- In the biggest EU producer Netherlands, natural gas production in Q2 2021 decreased by 10% (by 0.7 bcm), amounting to 5.9 bcm. In contrast, in Romania, being the second biggest gas producer in the EU, production went up by 10% (0.3 bcm), reaching 2.2 bcm in Q2 2021, however, one quarter's favourable numbers are not likely to break the downward trend. Gas production remained practically unchanged in Poland in Q2 2021, amounting to 1.3 bcm.
- In Germany, Italy and Ireland, where production respectively amounted to 1.1 bcm, 0.7 bcm and 0.4 bcm in Q2 2021, year-on-year decreases varied between 14% and 26% and production went down by around 0.1-0.3 bcm in each country. Gas output in Denmark amounted to 0.3 bcm, down by 6% year-on year, as the redevelopment of the Tyra field in the Danish North Sea (expected to come online only in 2023) had still impact on the country's gas production and exports.
- In the first half of 2021, Dutch gas production, amounting to 12.2 bcm, was down by 10% (-1.3 bcm), whereas in Romania production remained stable, reaching 4.6 bcm. Gas production in Poland was around 2.7 bcm in the first half of 2021, down by 1%, whereas in Germany, Italy, Ireland and Denmark gas production saw a double-digit fall in percentages, compared to the first half of 2020. Gas production in the EU amounted to 26.7 bcm in the first half of 2021, down from 29.4 bcm a year before.
- Gas production in Norway decreased by almost 9%, from 27.8 bcm in Q2 2020 to 25.3 bcm in Q2 2021, largely owing to the infrastructure maintenance works brought forward to the second quarter in 2021. In the first half of 2021, natural gas production in Norway amounted to 54 bcm, down from 59 bcm in the same period of 2020. In the United Kingdom, gas production amounted to 6.3 bcm in Q2 2021, significantly down from 10.5 bcm a year before, while in the first half of 2021 gas production reached 15.3 bcm, down from 21 bcm a year before.

⁶ Given that in some countries data for some periods are based on estimation, this number might retrospectively change

Figure 8 - Monthly gas production in the EU



Source: Eurostat, data as of 10 September 2021 from data series nrg_103m. In the next edition of this report numbers might change retrospectively.

1.3 Imports

- According to Eurostat⁷, net gas imports in the EU increased by 7% (6.2 bcm) in the second quarter of 2021 (year-on-year), amid increasing gas consumption and dwindling domestic production. Net imports in different EU countries showed a high variation in Q2 2021. In Hungary net imports rose by 38% (+0.8 bcm) year-on-year, and in Portugal they went up by 34% (+0.4 bcm). In Greece, Luxembourg, Slovenia and Spain net gas imports rose by more than 20% in Q2 2021, while they decreased by more than 20% in Denmark, the Netherlands and Austria. Looking at the biggest importers, in Spain net gas imports rose by 23% (+1.5 bcm), in Belgium by 19% (+0.7 bcm), in Germany by 16% (+3 bcm), in Poland by 15% (+0.7 bcm), and in Italy by 10% (+1.7 bcm). At the same time, net gas imports were down by 26% (-1.7 bcm) in the Netherlands and by 7% (-0.8 bcm) in France. The biggest importers in the EU were Germany (21 bcm), Italy (19 bcm), France (11 bcm), Spain (8 bcm), the Netherlands and Poland (both slightly below 5 bcm). These six countries represented together around three quarters of the total EU net gas imports in Q2 2021, which amounted to 90.7 bcm, up from 84.5 bcm in Q2 2020.
- In the first half of 2021, net gas imports in the EU amounted to 170.3 bcm, up from 165.5 bcm in the first half of 2020 (representing an increase of 3%). Germany imported 43 bcm of gas, followed by Italy (36.6 bcm), France (20.6 bcm), Spain (16.5 bcm), and Belgium (10.2 bcm).
- According to ENTSO-G data, net imports amounted to 959 TWh in the second quarter of 2021, of which 77% arrived through pipelines and around 23% through LNG terminals. Pipeline gas imports from Russia, extending the increase of the previous quarter, rose by 5% in year-on-year comparison. In contrast, imports from Norway were down by 11% in Q2 2021 in year-on-year comparison. Pipeline gas imports from Algeria, continuing the trend of the previous quarter, showed a remarkable, triple-digit increase (223%) in Q2 2021. Pipeline gas imports from Libya fell further, by 40% year-on-year. At the same time, LNG imports reached 223 TWh in Q2 2021.
- Similarly to the previous periods, Russia was the top gas supplier of the EU and the share of Russian pipeline gas in the extra-EU gas imports was 42% in the second quarter of 2021, up from 41% in Q2 2020⁸.
- The share of pipeline gas imports from Norway fell below 20% in the second quarter of 2021, and was the lowest since Q2 2015, as pipeline gas imports from Norway decreased (by 11%), contrasting the increasing import trend. Low gas inflows from Norway must have been related to bringing forward of the infrastructure (gas fields, pipelines) maintenance season to the second quarter

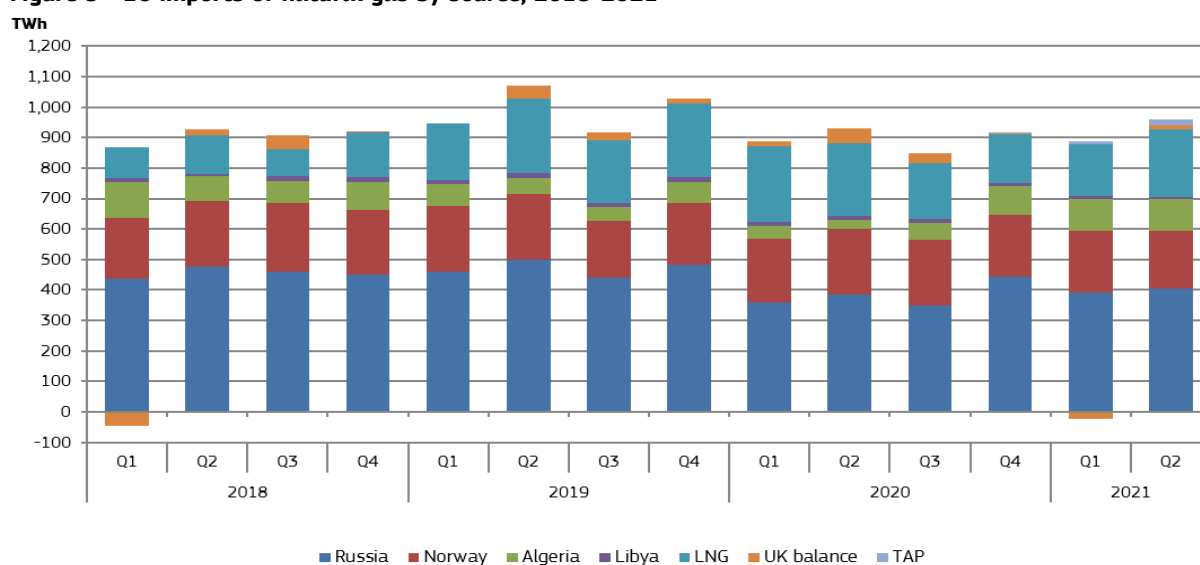
⁷ Net imports equal imports minus exports and do not account for stock changes.

⁸ It is worth to note that Russia increased its importance in the EU LNG imports as well over the last two-three years, numbers presented in this section, with the exception of LNG or unless otherwise indicated, refer to pipeline imports

of the year, normally taking place in the third quarter. In the second quarter of 2021, Norwegian gas production⁹ amounted to 27.8 bcm, decreasing by 9% year-on-year.

- In the second quarter of 2021, pipeline gas imports from Algeria increased significantly, by 223% year-on-year, which resulted in an increasing share within the total extra-EU imports (11% in Q2 2021 up by 7 percentage points compared to Q2 2020). Increasing pipeline gas imports from Algeria must have been related to the oil-indexed contracts, becoming competitive to hub based pricing, in consequence of the recent steep increase in wholesale gas prices on the European hubs. Imports from Libya continued to fall and its share was only 0.8% (the lowest since Q2 2018) in the total EU gas imports, even decreasing from 1.4% in Q2 2020.
- In Q2 2021, the share of LNG was 23.2% in the total EU gas imports, the highest since Q2 2020, but 2 percentage points lower year-on-year. Decreasing LNG imports in the EU was principally owing to the high price premium of the Asian gas markets to Europe, resulting in redirection of LNG cargoes towards Asia, amid widespread maintenance works on LNG facilities, already making the LNG supply tight. It seems that the decreasing share of Norwegian pipeline gas, LNG, and inflows from the UK between the second quarters of 2020 and 2021 was mainly compensated by the increasing share of Algerian and Russian pipeline sources in EU gas imports, and the appearance of the TAP pipeline as new supply route.
- The Trans Adriatic Pipeline (TAP), operational since the end of 2020, ensured around 18 TWh gas imports in the EU in the second quarter of 2021, amounting to around 1.9% of the total imports. TAP provides access to Azerbaijani gas resources via the Southern Gas Corridor, an important result of the EU security of gas supply policies.
- In the first half of 2021, gas imports in the EU amounted to 1 824 TWh, slightly up by 0.5%. Russian pipeline gas was the biggest supply source (44%), followed from pipeline gas from Norway and LNG regasification terminals (both between 21 and 22%), Algerian pipeline gas (11%) and pipeline gas via the TAP (1.5%) and from Libya (1%).

Figure 9 - EU imports of natural gas by source, 2018-2021



Source: Based on data from the ENTSO-G Transparency Platform, data as of 13 September 2021.

Exports to the Baltic-states and Finland are not included in the chart owing to unavailability of reliable data

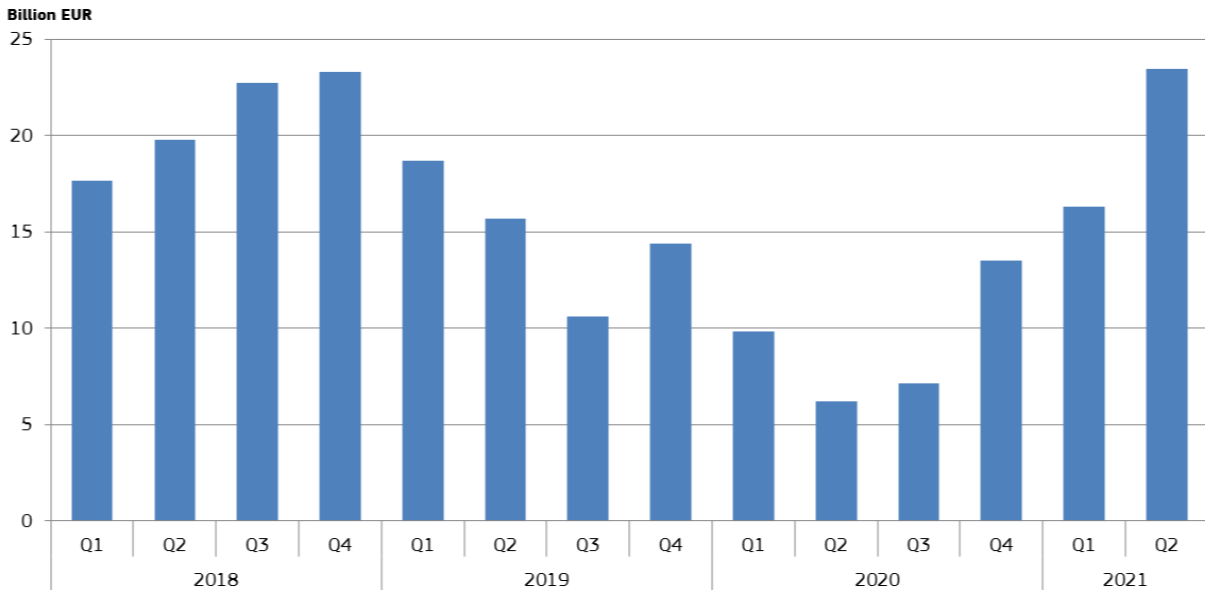
Russia, Norway, Algeria and Libya include pipeline imports only; LNG imports coming from these countries are reported in the LNG category.

A trade balance with the UK is estimated, reflecting that the UK is no longer part of the EU, and it is not easy to determine the origin of gas molecules arriving to the EU after going through the UK market (it can be UK production, imports from Norway of LNG imports from the UK, etc.). As of 2021, imports via the Trans Adriatic Pipeline (TAP) is also included.

- Overwhelmingly due to the significantly increasing average import prices year-on-year (more than tripling, rebounding from extreme lows in Q2 2020), in the second quarter of 2021 the estimated gas import bill amounted to €23.5 billion, in comparison to €6.2 billion in Q2 2020, rising by 279% year-on-year. Wholesale gas prices in Europe, following an increasing trajectory, were up by an estimated 267% in Q2 2021 year-on-year. The quarterly gas import bill was also up in Q2 2021 compared to the previous quarter (€16.3 billion in Q1 2021). In the first half of 2021 the EU gas import bill amounted to €39.8 billion, up from €16.1 billion in the first half of 2020.

⁹ <https://www.npd.no/en/facts/news/Production-figures/2020/production-figures-march-2020/>

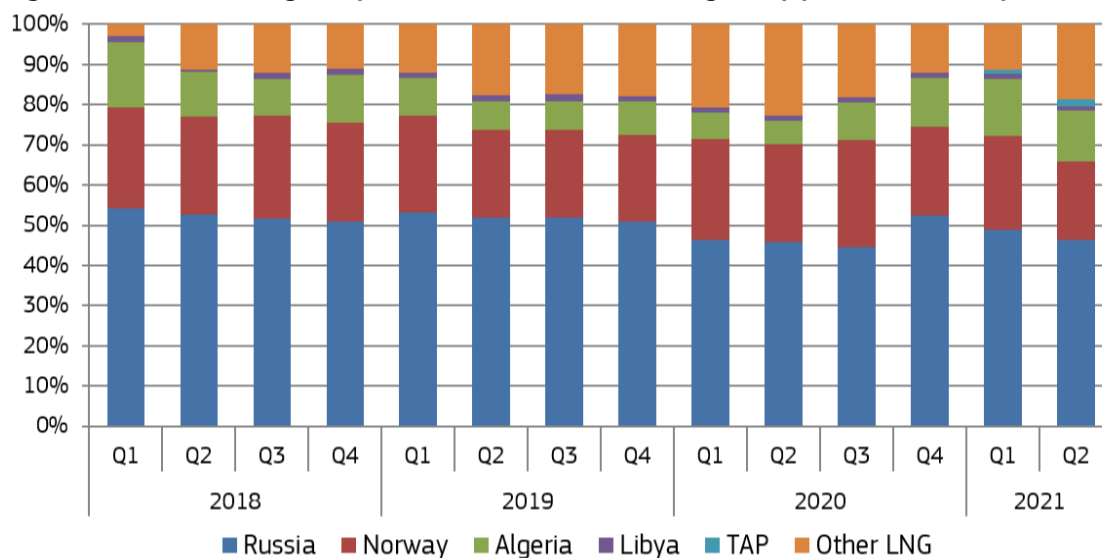
Figure 10 – Estimated quarterly extra-EU gas import bill, in billions of euros



Source: ENTSO-G, Eurostat and own data calculations for the EU weighted average of import gas prices

- As important pipeline gas source countries, such as Russia, Norway and Algeria are also active on the LNG market; the quarterly gas report also takes a look at the combined imports of pipeline gas and LNG from these countries and attempts to calculate the share of import sources in this way, too. As Figure 11 shows, the share of Russia within total extra-EU gas imports (pipeline and LNG together) amounted to 47% in Q2 2021, split by 42% of pipeline imports and 5% of LNG, indicating that Russia is also an important participant in European LNG imports, not only in the traditional pipeline gas supply. Russia is trying to maintain its market share by switching to a more competitive export strategy. The share of pipeline import gas of Russian origin went up from 41% to 42% within the total extra-EU gas imports, by taking into account LNG the share of Russia rose from 46% to 47% in Q2 2021 year-on-year.
- The share of Norway was 20% in Q2 2021 (practically the same share as the Norwegian pipeline imports, owing to ongoing repair and maintenance works on the country's sole LNG plant). The share of Algeria was more than 13% with LNG (as opposed to 10.6% only including pipeline gas) within the total extra-EU gas imports. The share of LNG was 19% in Q2 2021, (on the top of LNG accounted in shipments from Russia, Norway and Algeria), down from 22% in Q2 2020 but up from 11% in the previous quarter. The decreasing share of imports from Norway and other LNG between the second quarters of 2020 and 2021 was mainly compensated by the increasing shares of Algeria, and the new TAP pipeline supply route, whose share was 1.9% in the total extra-EU gas imports in Q2 2021.

Figure 11 – The share of gas imports within the total, combining both pipeline and LNG imports

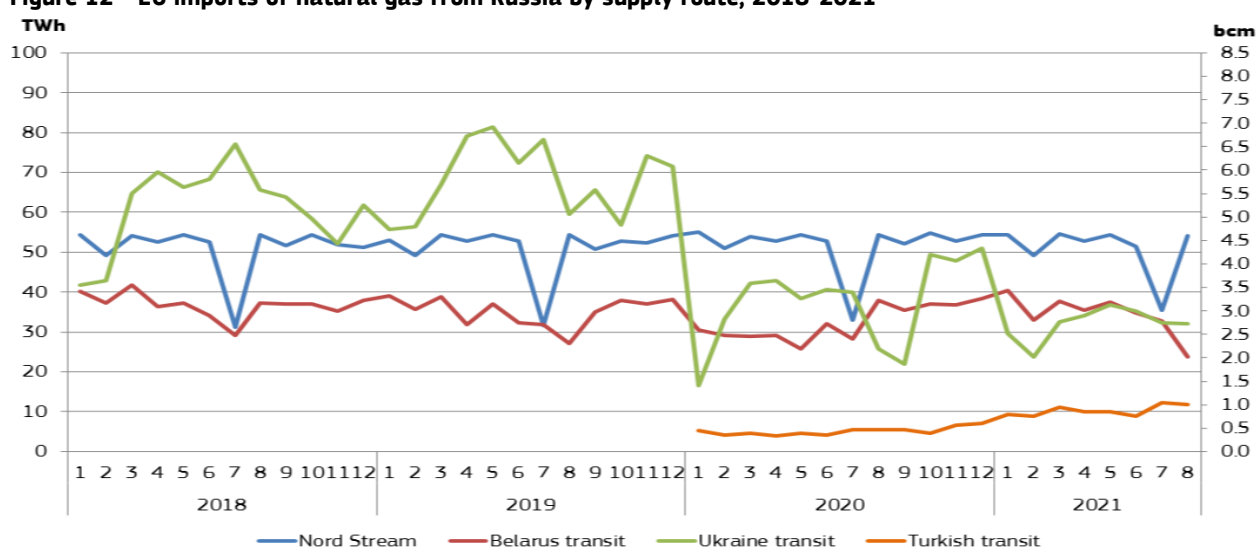


Source: Based on data from the ENTSO-G Transparency Platform, data as of 13 September 2021.

1.3.1. Pipeline imports from Russia and EU supply to Ukraine

- Figure 12 shows the breakdown of EU gas imports from Russia on the four main pipeline supply routes: Ukraine (which includes the Brotherhood Pipeline and the - recently less important - Balkan route), Belarus (mainly the Yamal pipeline), Nord Stream 1 and Turk Stream.
- In the second quarter of 2021, the volume of Russian imports rose by 5%, if compared with the same quarter of 2020. As shown on Figure 12, gas flows transiting via Ukraine were almost 13% lower than in Q2 2020, implying a steeper fall than that in the previous quarter (7%). During Q2 2021 a monthly average of 3.3 bcm of gas of Russian origin was transited through Ukraine, implying a decrease compared to Q2 2020 (3.8 bcm), however, an uptick compared to the first quarter of 2021 (2.7 bcm). Interestingly, imports were still down through Ukraine, even during the second quarter, comparing with a very low base of early 2020.
- In contrast to Ukraine, flows through Belarus were up by 24% in Q2 2021 year-on-year. Transited volumes through the Nord Stream were slightly down by 0.7% in Q2 2021 compared to the second quarter of 2020. At the same time, transited volumes through the Turk Stream, operational since the beginning of 2020, were up by 128% in Q2 2021 year-on-year, and the average monthly transited volume was 0.9 bcm in Q2 2021.
- As a result, in Q2 2021 Nord Stream remained the main supply route of Russian gas to Europe, as its share reached 40% of the total Russian pipeline gas imports in the EU, though slightly down from 42% a year earlier. The Belarus transit route remained the second most important supply route, similarly to the previous quarter, and represented 27% in Q2 2021, up from 23% in Q2 2020. The share of the transit through Ukraine stabilised at the third place, ensuring only 26% of the total Russian pipeline gas transit, down from 32% year earlier, though coming back from the through of 22% measured in Q1 2021. The share of Turk Stream reached 7% in Q2 2021, slightly down from 8% in Q1 2021 but up from only 3% in Q2 2020.
- In Q2 2021 Nord Stream represented 17% (15 bcm) in the total net extra-EU gas imports, the Belarus transit route ensured 11% (10 bcm), similarly to the Ukrainian transit, having a share of 11% (10 bcm). At the same time, the Turk Stream had a share of 3%, with around 2.8 bcm gas transit within the total net extra-EU gas imports in Q2 2021. It seems that in Q2 2021 the European demand increase for Russian gas was principally satisfied via the Belarus route and the Turk Stream, whereas the Ukrainian transit decreased further, amid stagnating volumes on Nord Stream.
- In the first half of 2021, transited volumes through Nord Stream was almost 30 bcm (-0.9% year-on-year), Belarus transit reached 20.5 bcm (24.5%), the Ukraine transit (only counting the destinations within the EU) was 18 bcm (-10.3%), while transit on Turk Stream was around 5.4 bcm, up by 118%. Looking at the three summer months (June-August, important period for storage refilling in the EU and pipeline maintenance), it is remarkable that flows through the Belarus route were down by 7%, and Ukrainian transit was also down by 6%. In Q2 2021 Gazprom booked less interconnection capacities on infrastructure transiting gas through Ukraine, and in early days of July 2021, contrarily to market expectations, it did not book additional capacities through Ukraine, Yamal and the Turk Stream, which some market actors interpreted as a trial to convince European partners for the need of swift finalisation and putting into operation the new Nord Stream 2 pipeline.

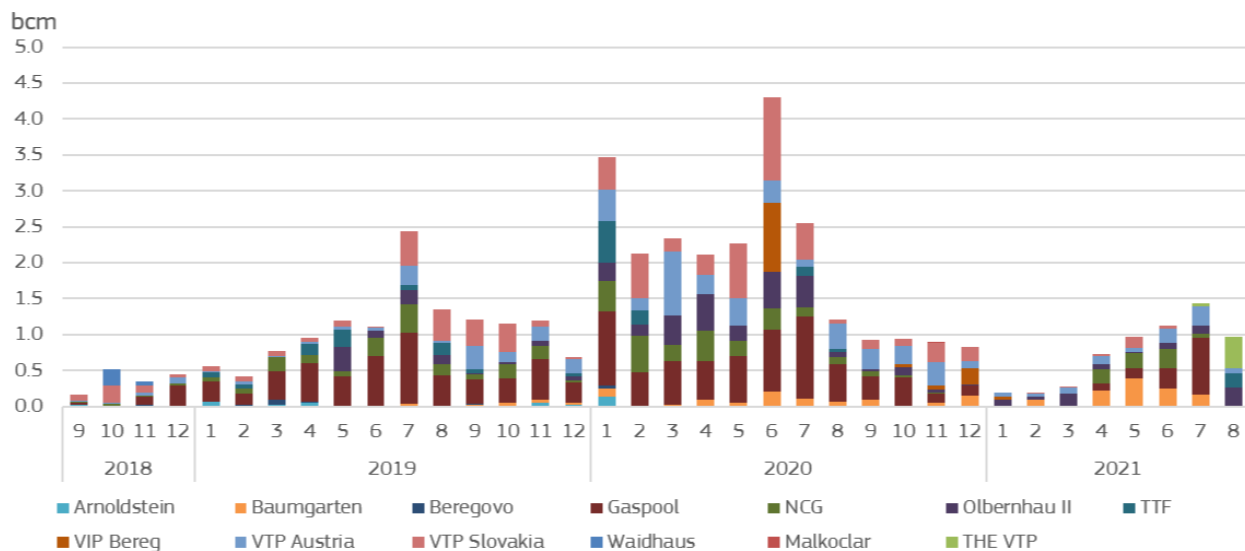
Figure 12 - EU imports of natural gas from Russia by supply route, 2018-2021



Source: Based on data from the ENTSO-G Transparency Platform, data as of 13 September 2021. Deliveries to Estonia, Finland and Latvia are not included; transit volumes from Russia to the Republic of North Macedonia and Serbia are excluded. Since the inauguration of Turk Stream flows to Turkey via the Balkans are not significant.

- Traded volumes on Gazprom Electronic Sales Platform (ESP), after reaching all-time low (since the beginning of the trade in 2018) in Q1 2021 (0.64 bcm), picked up slightly in Q2 2021 and reached 2.8 bcm. However, traded volumes in Q2 2021 were still down by two quarters year-on-year. In June 2021 traded volumes were above 1 bcm, however, this is to compare with the 4 bcm volume of June 2020. In July 2021 volumes continued to increase, followed by a retreat in August.
- Increase in traded volumes, especially on the curve, might have been related to increasing spot and forward gas prices on the EU hub, making the long-term contract prices more competitive. In Q2 2021 the principal delivery points from ESP sales were Baumgarten (0.9 bcm), the two German hubs, NGC (0.7 bcm) and Gaspool (0.5 bcm), Austrian virtual trading point (VTP Austria – 0.4 bcm) and the Slovak virtual trading point (VTP Slovakia – 0.2 bcm).

Figure 13 – Monthly sales on the Gazprom Electronic Sales Platform (ESP) with delivery points



Source: Gazprom Electronic Sales Platform

- Gazprom expects the 2021 gas exports to Europe (including the EU, non-EU member countries on the Balkans and Turkey) in the range of 175-183 bcm, as was announced on 29 April 2021¹⁰. Some interesting details on contract pricing was also revealed: in 2020, some 56% of its export volumes in 2020 were indexed to day-ahead or month-ahead prices, while 31% had a link to forward prices (quarter, season and year-ahead), and the remaining 13% was oil-indexed, implying that around 87% was indexed to hub contracts, denominated in euros.
- According to data from the Ukrainian gas TSO, natural gas transportation from EU countries to Ukraine fell to low levels in Q2 2021, as in April, May and June monthly imports respectively reached 77 mcm, 8 mcm and 90 mcm, adding up to 175 mcm in the quarter. In the first quarter of 2021 Ukrainian imports from the EU still amounted to 476 million cubic meters¹¹. In July and August 2021 imported volumes picked up, respectively reaching 498 mcm and 567 mcm. Most of natural gas was imported via Hungary (above 80%), while Slovakia and Poland had lower shares. As new import route, Trans Balkan Pipeline, used until the end of 2019 to ship Russian gas to the Balkans, was tested within the framework of a pilot and Ukraine imported gas in this reverse direction from Romania.

1.3.2. LNG imports

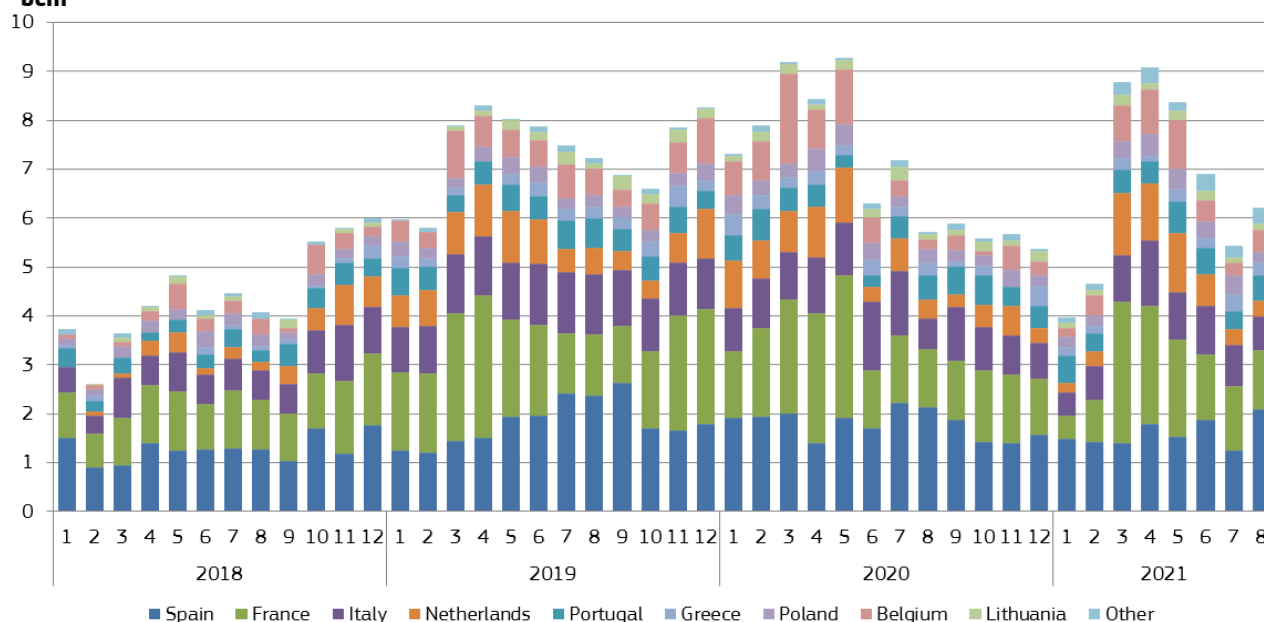
- LNG imports in the EU, after four quarters of year-on-year decreases, managed to slightly increase, by 1%, in Q2 2021, signalling the impact of economic rebound and demand for more gas, sharply contrasting the decrease of 29% in LNG imports in Q1 2021. Looking at the three months of the quarter, EU LNG imports were respectively up by 8% in April and by 9% in June, however, in May imports showed a year-on-year decrease of 10%. The quarterly LNG import in Q2 2021 in the EU was 24.4 bcm, higher than in Q1 2021 (17.4 bcm), and slightly up from 24 bcm in Q2 2020, as Figure 14 shows. The total number of LNG cargoes arrived in the EU was 318 in Q2 2021, up from 239 in Q1 2021 and from 294 in Q2 2020. In July and August 2021, owing to increasing global competition, LNG imports in the EU remained volatile (decreasing by 24% in July and rising by 9% in August year-on-year).

¹⁰ <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/042921-gazprom-sees-2021-european-gas-exports-in-range-of-175-183-bcm-burmistrova>

¹¹ <https://tsoua.com/en/news/ukraine-imported-about-567-million-cubic-meters-of-gas-from-eu-in-august>

- In Q2 2021 France became the biggest quarterly LNG importer, overtaking Spain, and importing 5.8 bcm of LNG, however, in year-on-year comparison imports were down by 15%. Spain came to the second place, importing 5.2 bcm, 4% more than in Q2 2020. Italy was the third biggest importer, (with 3.3 bcm, dropping by 9% year-on-year). The Netherlands came to the fourth place, with the quarterly imports amounting to 3 bcm, implying an increase of 23% in Q2 2021 year-on-year. Belgium imported 2.3 bcm of LNG (-5% year-on-year), followed by Portugal (1.6 bcm, +68%) and Poland (1.2 bcm, +2%). Among LNG importing EU countries, Sweden showed the biggest year-on-year increase in Q2 2021 (+134%, though with a small volume of 0.14 bcm), whereas LNG imports fall the most in Greece (-30%, with 0.6 bcm of volume). Croatia, who started to import LNG only this year, had a quarterly import of 0.47 bcm in Q2 2021. The total EU LNG imports amounted to an estimated €6.6 billion in Q2 2021, up from €1.4 billion a year before, principally owing to the impact of sharply increasing wholesale gas prices (up by 372%) year-on-year.
- LNG imports in the United Kingdom fell by 5% in Q2 2021, reaching almost 4.9 bcm. The UK has always been playing an important role as berthing site of LNG vessels for continental Europe and shipments are transported to Europe via gas interconnectors with Belgium and the Netherlands. It seems that LNG suppliers to the UK were more flexible in redirecting their shipments to other market, where sale prices were higher.
- In the first half of 2021 EU countries imported 42 bcm of LNG, which was lower than in the first half of 2020 (48 bcm). In the first half of 2021 France imported 10 bcm of LNG, followed by Spain (9.5 bcm), Italy (5.4 bcm), the Netherlands (4.8 bcm) and Belgium (3.6 bcm). In the first half of 2021, the UK imported 10 bcm of LNG, down from 11.1 bcm in the same period of 2020.
- As in Q2 2021 demand for gas was strong in the Asian markets, wholesale prices showed an increasing trend which also dragged up wholesale gas market prices in the EU (see Figure 24 and Figure 25). Asian markets showed higher profitability, resulting in LNG cargos being directed to Asia. Even though Europe has a good geographical position, offering proximity to cargos from the Atlantic Basin, the Middle East and LNG of Russian origin (production at the Yamal Peninsula), resulting in favourable shipment costs, if price premiums are high enough in Asia, LNG exporters will direct shipments there to benefit from higher profitability. Other developments on the demand and supply side of the market played also role in LNG cargo arrivals in Europe (see more in the Focus on part on the impact of the global gas market on European prices).

Figure 14 - LNG imports to the EU by Member States
bcm

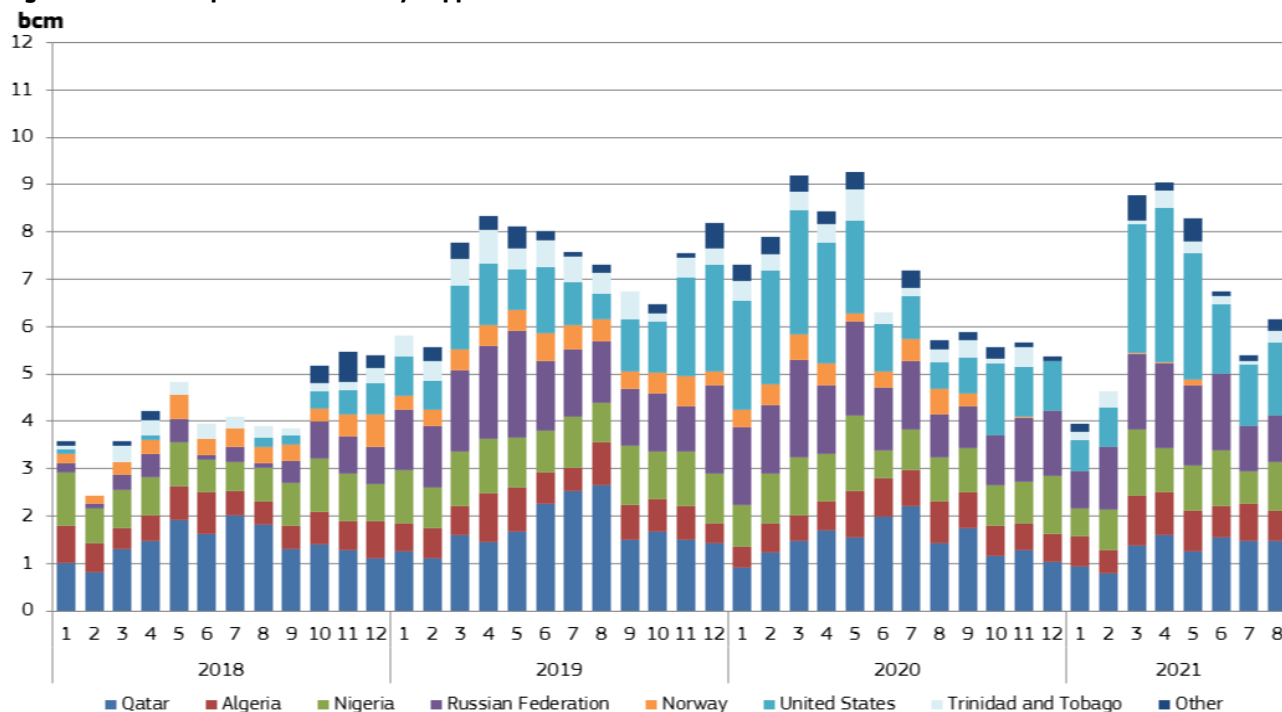


Source: Commission calculations based on tanker movements reported by Refinitiv "Other" includes Finland, Malta and Croatia

- In the second quarter of 2021 the United States were the largest LNG supplier of the EU, ensuring 31% (7.4 bcm) of the total EU LNG imports. The share of the US in the total EU LNG imports (31%) was the highest since US exports began to Europe. Russia came to the second place (with an import share of 21% - 5.1 bcm) and Qatar to the third (18% - 4.4 bcm). In year-on-year comparison, the share of the US rose by 8 percentage points whereas the share of Russia was up by 1 percentage point, and that of Qatar went down by 4 percentage points. Nigeria was the fourth biggest import source in Q2 2021, (with imports of 3.1 bcm an unchanged market share), followed by Algeria (with 2.5 bcm of imports and market share up from 6% to 10% year-on-year). Trinidad and Tobago ensured 3% of imports – See Figure 15.

- In Q2 2021, Norway had a share of less than 1% in total EU LNG imports, similarly to the previous quarter and down from 4% in Q2 2020. This decrease can be explained by the ongoing outage of the Hammerfest LNG plant due to a fire incident¹² in September 2020, which, requires ongoing repair and maintenance works. Based on extensive analyses and mapping of damages, in April 2021 terminal operator Equinor has updated the schedule¹³ for repair and start-up of the LNG plant. Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022.

Figure 15 - LNG imports to the EU by supplier



Source: Commission calculations based on tanker movements reported by Refinitiv

Imports coming from other EU Member States (re-exports) are excluded

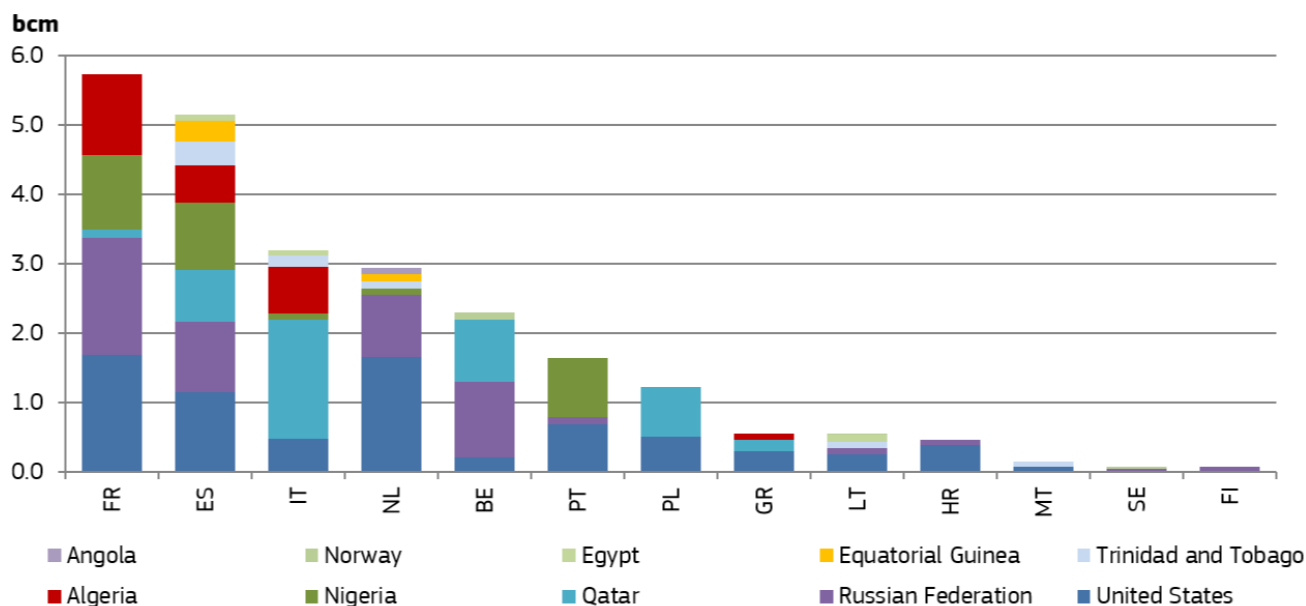
Other includes Angola, Brazil, the Dominican Republic, Egypt, Equatorial Guinea, Oman, Peru, Singapore, the United Arab Emirates and Yemen

- In the second quarter of 2021, the United States were the biggest LNG supplier in Croatia (82% of the total LNG imports), the Netherlands (56%), Greece (55%), Malta (50%), Lithuania (48%) and Spain (22%), it came to the second place in Portugal (42%) and Poland (41%), and were in a neck to neck race with Russia in France (29%). Russia was the sole supplier in Finland (100% of the country's total LNG imports), and was the biggest supplier in Sweden (55%), Belgium (48%) and came to the second place in the Netherlands (30%), France (29%), Spain (20%), Croatia (18%) and Lithuania (16%), implying that Russian LNG has increasing importance in the EU, especially in North-Western Europe, not independently from the dwindling domestic gas production in the Netherlands. Qatar was the biggest supplier in Poland (59%) and Italy (54%) and was the second biggest in Belgium (39%) and Greece (29%).
- Nigeria was the biggest supplier in Portugal (52%), and ensured 19% of all LNG imports in Spain and France. Algeria ensured 21% of the French and Italian LNG imports in Q2 2021, and around one sixth of Greek LNG supply. Trinidad and Tobago ensured half of the LNG imports in Malta and around 16% of LNG imports in Lithuania. Egypt had a share of 17% in the Lithuanian LNG imports. Albeit having minimal exports, Norway ensured 45% of the Swedish LNG imports In Q2 2021. Spain had the most diversified LNG import source structure, receiving cargoes from eight different countries, followed by Italy and the Netherlands, each with six different import sources. On the other hand, Finland had a single supplier of LNG sources in Q2 2021.

¹² See more in the Quarterly Report on European Gas Markets, fourth quarter of 2020 (Vol 13, issue 4).

¹³ <https://www.equinor.com/en/news/20210426-hammerfest-lng.html>

Figure 16 – LNG imports in the EU Member States from different sources in the second quarter of 2021



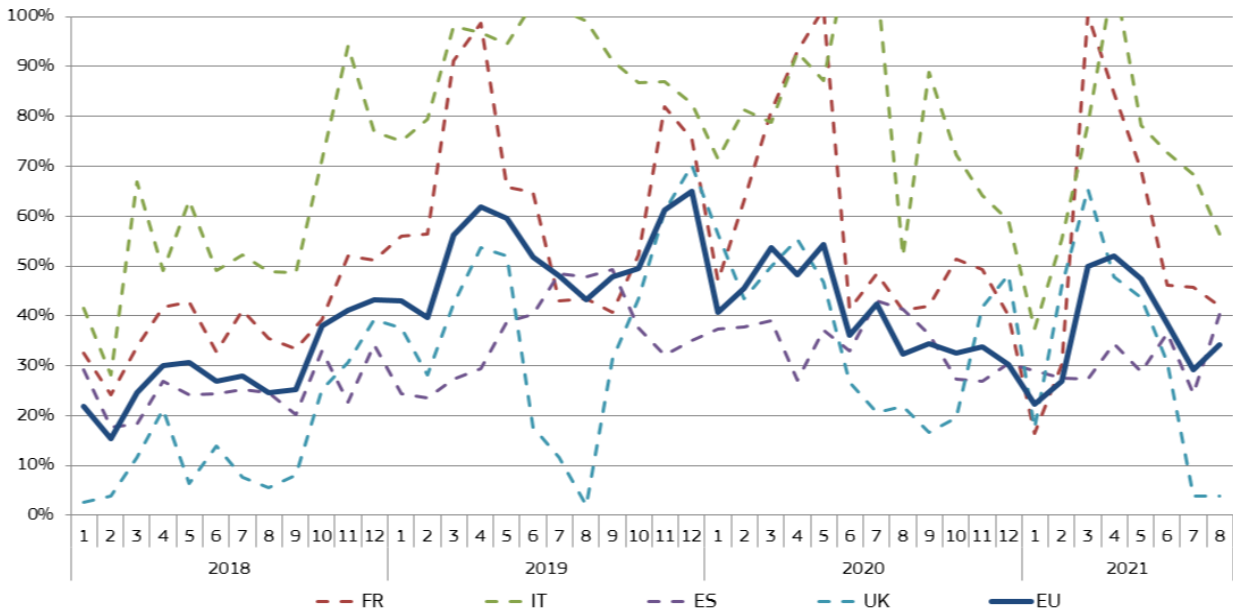
Source: Commission calculations based on tanker movements reported by Refinitiv

Imports coming from other EU Member States (re-exports) are excluded

"Other" includes Angola, Brazil, the Dominican Republic, Egypt, Oman, Singapore, the United Arab Emirates and Yemen

- In the second quarter of 2021, 78 LNG cargoes arrived from the US (up from 44 in Q1 2021 and from 59 in Q2 2020). LNG imports from the US amounted to 7.4 bcm in Q2 2021, up from 5.5 bcm in Q2 2020. The estimated market value of LNG imports from the US was around €2 billion in Q2 2021.
- LNG exports to Europe represented 31% in Q2 2021 of the total US exports, which was much higher than in the previous quarter (18%) but was lower than in Q2 2020 (36%). In the second quarter of 2021 the four most important EU destinations of the US LNG exports were France (1687 mcm), the Netherlands (1657 mcm), Spain (1156 mcm) and Portugal (691 mcm). The United Kingdom imported 667 mcm of US LNG in Q1 2021, up from 376 mcm in Q2 2020.
- The average monthly LNG terminal utilisation rates are presented on Figure 17 for some EU countries, the EU on average, and the UK. The average EU utilisation rate, which stood in March 2021 at 50%, rose to 51% in April, but fell back to 38% in June 2021 (and fell even lower in July and August). This was strongly related to the intensive international competition for LNG supplies. At individual terminal or country level, monthly utilisation rates can be quite volatile, depending on the arrival of cargoes and the hourly regasification capacities. In Italy and France, utilisation rates rose to high levels (above 70% in April and May, but fell back in June, though remained higher than the EU average during the whole Q2 2021). On the other hand, in Spain utilisation rates were lower than EU average during the whole Q2 2021. In the UK utilisation rates were rapidly falling over Q2 2021, and by July and August they fell to the lowest (around 3-4%) since August 2019, probably owing to maintenance works on the regasification terminals.

Figure 17 – Average monthly regasification terminal utilisation rates in the EU and in some significant LNG importer countries



Source: Commission calculations for LNG imports based on tanker movements reported by Refinitiv. Regasification capacities are based on data from International Group of Liquefied Natural Gas Importers (GIINGL) and Gas Infrastructures Europe (GIE)

1.4 Policy developments and gas infrastructure

- On 1 April 2021, European gas pipeline link EUGAL has reached its full transport capacity, with two strings and a compressor station¹⁴. The first string has already been transporting natural gas since 1 January 2020. The second string and the compressor station became operational and expanded the transport capacity to up to 55 bcm of natural gas per year. EUGAL is an important component in Europe's energy supply, running over a length of around 480 kilometers from Lubmin on the Baltic Sea to Deutschneudorf on the German-Czech border.
- On 21 April 2021, the cooperation contract, which provides for the merger of the two gas market areas GASPOOL and NetConnect Germany to form the Trading Hub Europe (THE) market area, was signed¹⁵ in Berlin. THE will benefit shippers and end users, network operators and balancing group managers alike. Due to its central location in the heart of Europe, the new Germany-wide market area will act as an international hub linking other European gas markets. The launch date for the nationwide market area is 1 October 2021. The market area manager's responsibilities will include balancing group management, operation of the virtual trading point and the procurement of balancing gas for the new market area.
- On 3 June 2021, the Danish Environmental and Food Appeals Board repealed the environmental permit issued in July 2019 for the construction of the 210 km onshore pipeline section of the Baltic Pipe¹⁶, which would allow Norwegian gas to flow to Poland. The setback will likely delay the project, which was fully permitted with onshore construction work already underway. Poland's state-owned natural gas producer and distributor PGNiG reserved 8.2 bcm per year of the project's capacity. Baltic Pipe was scheduled to be completed in October 2022, at the same time as PGNiG's long-term supply contract with Gazprom, under which it purchases up to 10.2 bcm per year of gas, expires. However, this step would likely result in a later operation, in 2023 at earliest.
- Several developments occurred during the last few months on the EU energy and climate policy domain. On 11 June the Council has reached a general approach on the revision of the Trans-European Networks for Energy (TEN-E) Regulation¹⁷. The objective of the revised TEN-E regulation is to modernise, decarbonise and interconnect the EU's cross-border energy infrastructure in order to help the EU achieve its 2050 climate neutrality objectives. On 28 June, the European Council approved the European Climate Law, making the EU-27 greenhouse gas emissions targets legally binding¹⁸. Negotiators from Parliament and EU Member States reached a deal already in April on the climate law. On 14 July, the European Commission adopted a package of proposals¹⁹ to make the EU's climate, energy, land use, transport and taxation policies fit for reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels.
- On 15 July 2021, the European Court of Justice refused to overturn a ruling limiting Gazprom's access to the OPAL pipeline, which links the Russian gas producer's Nord Stream line to the Germany grid²⁰. The court has rejected arguments of Germany, claiming that "energy solidarity" was a political concept rather than a legal issue, saying the Commission was required to examine possible risks to security of gas supply to EU markets. As it was clarified, 'the legality of any act of the EU institutions falling within the European Union's energy policy must be assessed in the light of the principle of energy solidarity'. The 470-km OPAL pipeline, which links Nord Stream 1 with onshore European gas grids, runs from northern Germany to the Czech Republic and has an annual capacity of 36 billion cubic metres of natural gas.
- On 21 July 2021, Germany and the United States reached a deal on Nord Stream 2 pipeline²¹, being necessary for its finalisation and putting in operation, formerly strongly opposed by the US, and parties participating in its construction were facing risks of commercial sanctions. According to the deal, should Russia intend to use gas shipments for geopolitical pressure in Ukraine and Central Europe, Germany will take action at the national level and press for effective measures at the European level, including sanctions, to limit Russian export capabilities to Europe in the energy sector, including gas. The deal also foresees a commitment on the continuation of gas shipments through Ukraine after 2024, extending the trilateral EU-Ukraine-Russia agreement to ten years.
- Moreover, to support energy and climate transition, Germany and the US would invest \$1 billion (€0.85 billion) in a "Green Fund" to foster Ukrainian green-tech infrastructure, encompassing renewable energy and related industries, with the goal of improving Ukraine's energy independence. In September 2021, Gazprom announced the completion of the pipe-laying procedure for the Nord Stream 2 pipeline, however, the permission procedure with the German authorities might take several months before the pipeline is actually put in operation.

¹⁴ <https://www.gascade.de/en/press/press-releases/press-release/eugal-volle-kapazitaeten-stehen-bereit>

¹⁵ https://www.net-connect-germany.de/Portals/2/22.04.2021_PM_THE_en.pdf?ver=2021-04-22-100459-597

¹⁶ <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/060421-poland-says-it-is-analyzing-denmarks-baltic-pipe-environmental-permit-withdrawal>

¹⁷ <https://www.consilium.europa.eu/en/press/press-releases/2021/06/11/council-agrees-on-new-rules-for-cross-border-energy-infrastructure>

¹⁸ <https://www.reuters.com/business/sustainable-business/eu-countries-approve-landmark-climate-change-law-2021-06-28>

¹⁹ https://ec.europa.eu/commission/presscorner/detail/en/ip_21_3541

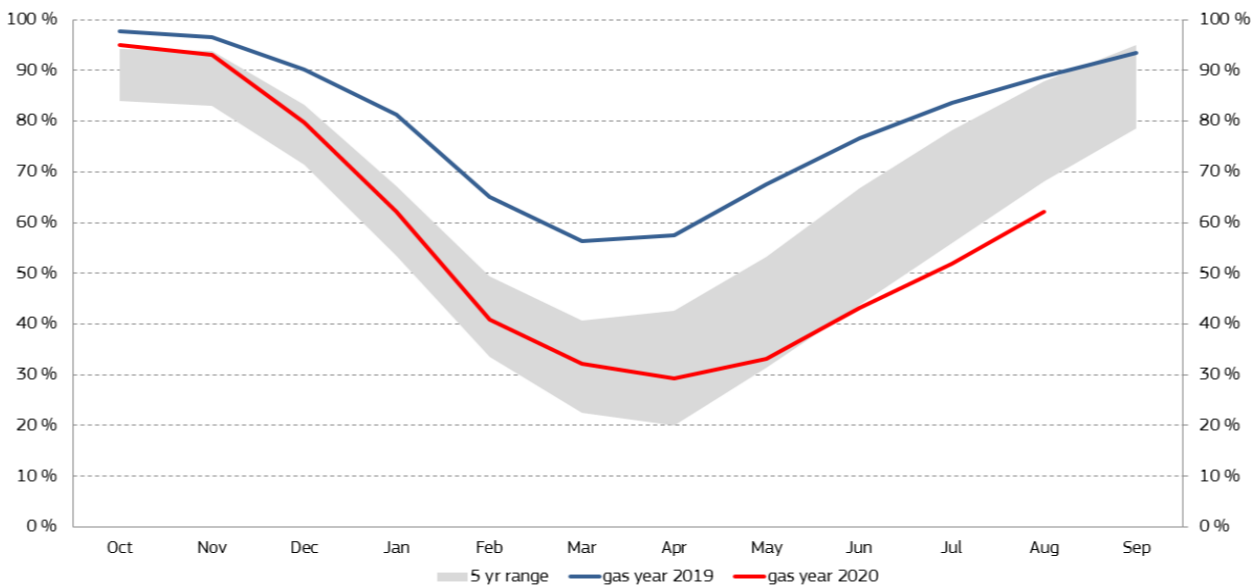
²⁰ <https://www.reuters.com/business/energy/eu-court-rejects-germanys-gazprom-pipeline-appeal-2021-07-15>

²¹ <https://www.auswaertiges-amt.de/en/newsroom/news/joint-statement-usa-and-germany/2472084>

1.5 Storage

- Figure 18 shows EU stock levels as the percentage of storage capacity in gas years²² 2019 and 2020, compared to the 5-year range of gas years 2014-2018. According to figures published by Gas Infrastructure Europe, operational EU storage capacity amounts to 1,148 TWh (roughly 102 bcm) as of July 2021²³.
- The second quarter of the year is traditionally the start of the refilling period of gas storages, after being depleted during the winter heating season. At this time of the year, storage withdrawals swap to injection, which last until the beginning of the fourth quarter. However, in April and May 2021, owing to consecutive cold spells in Europe, storage refilling was implemented slower than in the previous years.
- On 31 March 2021 the average EU storage filling rate was already lower than on the same day of 2020 (30.2% vs. 53.9%), owing to more intensive recourse to storage withdrawals during the winter period and decreasing LNG imports in Q1 2021. The average EU filling rate at the end of June 2021 (47%) was the lowest at this time of the over the last decade. Increasing gas consumption, owing to cold weather and the rebound of the EU economy, coupled with slowly increasing gas imports resulted in storage filling rates lagging behind the usual seasonal averages. Increasing spot wholesale market prices on the EU gas hubs did not help either to crank up storage injections. On 30 June, the difference between filling rates was even higher than on 31 March 2021, in comparison to 2020 (32.9% vs. 23.8%). As of the end of Q2 2021 and over the summer months, decade-low storage levels started to act as principal reason of rapidly increasing spot (and to lesser extent, forward) wholesale gas prices in the EU.
- As Figure 18 shows, as of May-June 2021 the curve showing the average storage level in the EU (gas year 2020) fell below the minimum of the last five years, a situation completely contrary to what could be observed in 2020 (gas year 2019). At the end of August 2021, storage levels were not so higher than in May 2020, which implies a three-month lagging behind compared to the last year.

Figure 18 - Gas storage levels as percentage of maximum gas storage capacity in the EU in the middle of the month



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 14 September 2021. See explanations on data coverage at <https://agsi.gie.eu/#faq>. The 5-year range reflects stock levels in gas years 2014-2018. The graph shows stock levels on the 15th day of the given month.

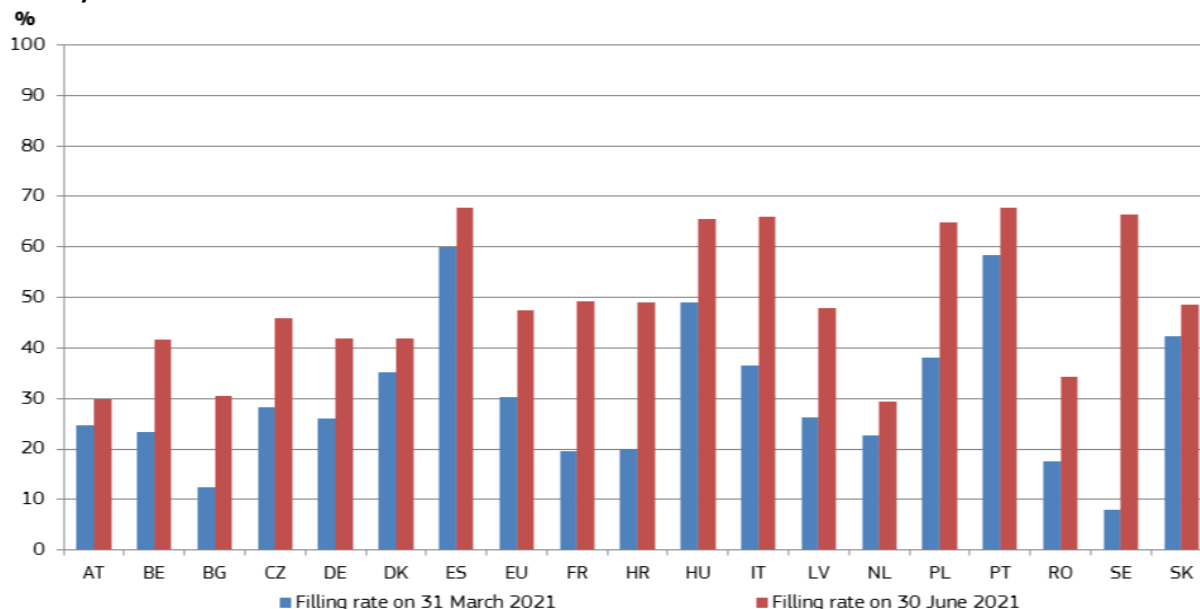
- As Figure 19 and Figure 20 show, on 31 March 2021, storage filling rates across the EU Member States ranged from 8% in Sweden (even though compared to low overall storage capacities), to 60% in Spain, reaching 30% on EU average. On 30 June 2021 however, differentials in filling rates were higher; the lowest filling rate could be observed in the Netherlands (29%), whereas the highest in Spain and Portugal (68%). The EU average filling rate was 47% on 30 June 2021, with filling rates lower than 40% in the Netherlands, Austria and Romania. Besides Spain in Portugal, the highest fullness rates could be observed in Sweden, Italy and Hungary (around 66% in each country).

²² Gas year always starts on the 1 October of a given year, for example, gas year 2020 started on 1 October 2020 and will end on 30 September 2021

²³ https://www.gie.eu/wp-content/uploads/filr/1410/2021_Storage_DB_final.xlsx

- The highest injection rates (between 31 March and 30 June 2021) could be observed in Sweden (58%), France, Croatia and Italy (29% in each country), whereas in Austria, Portugal and Spain filling rates increased by less than 10 percentage points during Q2 2021.

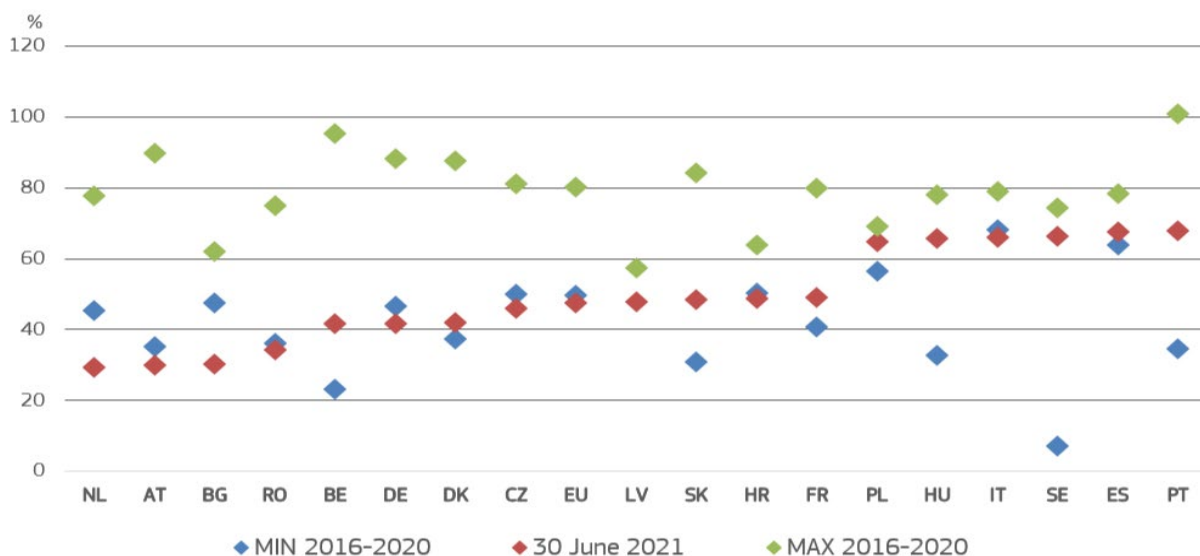
Figure 19 - Gas storage levels as percentage of maximum gas storage capacity at the end of the second quarter of 2021 by Member State



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 14 September 2021. See explanations on data coverage at <https://agsi.gie.eu/#faq>. Injection level data in Sweden changed significantly for the first time since the first data reporting period in March 2017. Nevertheless, the Swedish storage facility has a limited capacity (10 mcm), mainly used for LNG storage.

- Figure 20 also shows the filling rates on 30 June 2021, comparing to the minimum and maximum values in the time period of 2016-2020. Out of the 18 observed EU Member States, there were eight countries where filling rates on 30 June were lower than the minimum of the 2016-2020 period. Over this five-year period, for most of the countries the 2018 value represented the minimum (owing to an intensive cold spell at the end of the heating season), however, current numbers show that in many countries the 30 June 2021 filling rates were even lower than the 2018 respective values.

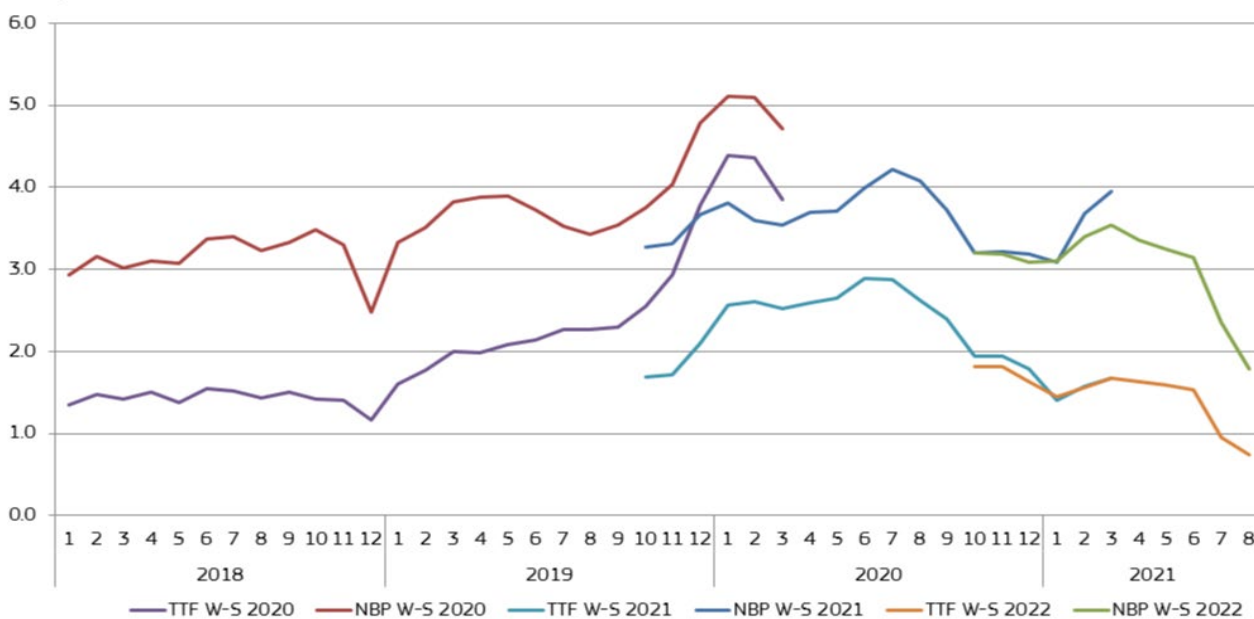
Figure 20 – Gas storage levels on 30 June 2021, compared to minimal and maximal levels of 2016-2020



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 14 September 2021.

- The next chart (Figure 21) shows the winter-summer spreads, as depicted by the difference in the 2021 and 2022 summer and winter contracts. Although 2021 seasonal spreads run out at the end of March 2021, they provided an indication for the incoming 2022 spreads.
- On the TTF, 2022 seasonal spreads were at 1.7 €/MWh in March 2021 and decreased slightly to 1.5 €/MWh in June and continued to fall during the summer, reaching 0.7 €/MWh in August 2021. At the same time, the seasonal spread on the NBP hub reached 3.4 €/MWh in March, decreased to 3.1 €/MWh in June and fell to 1.8 €/MWh in August 2021.
- It seems that both in continental Europe and in the UK the market anticipates less tightness on the gas market than in this year, as winter premium is much lower than the current spot and forward price differentials (or those in Q2 2021). However, if market fundamentals will not change, and harsh winter or supply crunch conditions occur, tight market expectations might filter in the 2022 spread contracts as well.

Figure 21 - Winter-summer spreads in the Dutch and British gas hubs
Euro/MWh



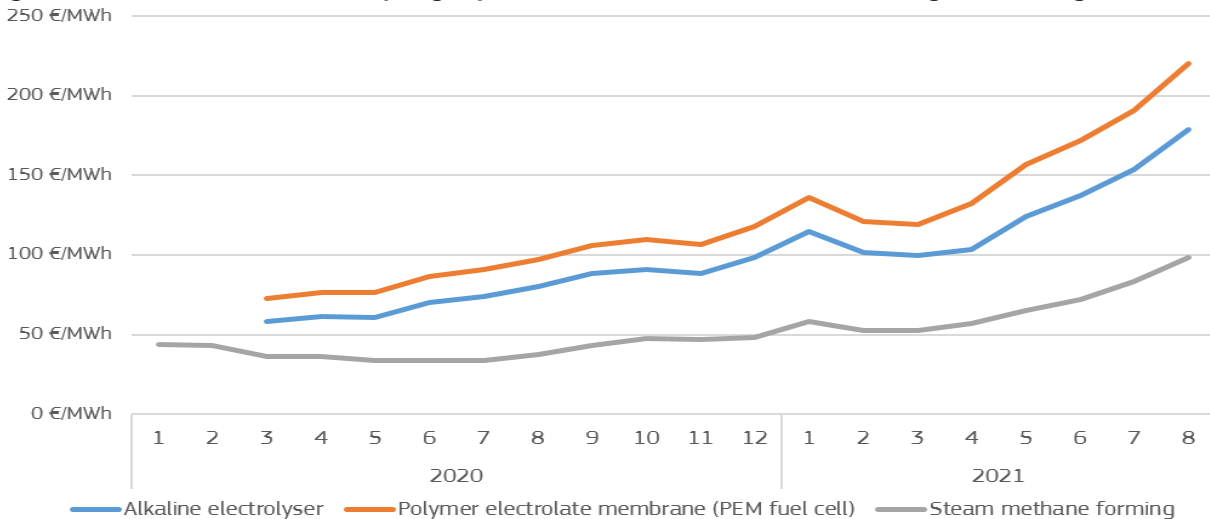
Source: S&P Global Platts

W-S 2020 refers to the premium of the winter 2020-21 contract over the summer 2020 price, W-S 2021 refers to the premium of winter 2021-22 contract over the summer 2021 price, and W-S 2022 refers to the premium of the winter period of 2022/23 over the summer 2022 price.

1.6 Hydrogen market developments

- The next chart shows the production cost-based estimated prices for hydrogen, generated by three different technologies. Alkaline water electrolysis is a type of electrolyser that is characterised by having two electrodes operating in a liquid alkaline electrolyte solution of potassium hydroxide (KOH) or sodium hydroxide (NaOH). A fuel cell is an electrochemical device that directly converts the chemical energy of reactants (a fuel and an oxidant) into electricity. Polymer electrolyte membrane (PEM) electrolysis is the electrolysis of water in a cell equipped with a solid polymer electrolyte that is responsible for the conduction of protons, separation of product gases, and electrical insulation of the electrodes. Steam methane forming (SMR) refers to a technology for producing hydrogen from natural gas; in the case on the chart below it includes the costs of Carbon Capture and Storage (CCS) as well.

Figure 22 - Production cost based hydrogen price assessments for different technologies (including CAPEX)



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

- Whereas alkaline electrolysis and PEM technology costs predominantly depend on the electricity price, the costs of SMR technology is driven by the cost of natural gas used for producing hydrogen. Alkaline and PEM are related to green power (hydrogen generation cost assessment is practically based on green power costs, adding EU wind guarantee of origin prices to wholesale electricity prices), whereas costs of SMR hydrogen generation is based on costs of natural gas (by adding CCS costs).
- In April 2021 the TTF spot gas hub prices averaged at 20.9 €/MWh, rising to 29.3 €/MWh in June and further to 44.3 €/MWh by August 2021. At the same time, the Pan-European Electricity wholesale price was around 59 €/MWh in April, rising to 74 €/MWh in June and to 90 €/MWh in August 2021. The significant increase in gas and electricity wholesale prices over the last few months could also be tracked in hydrogen price assessments.
- Cost-base assessment price for alkaline technologies rose from 103 €/MWh in April to 138 €/MWh in June (and to 179 €/MWh in August, with CAPEX costs), whereas prices of PEM fuel cell technology based generation rose from 132 €/MWh in April to 172 €/MWh in June (and to 220 €/MWh in August). These cost assessments were about twice as high as wholesale electricity prices. At the same time, SMR technology based costs assessments rose from 36 €/MWh in April to 51 €/MWh in June, and to 76 €/MWh in August, being also almost twice the wholesale natural gas price in each month. It seems that alkaline electrolyser and PEM technologies, through higher wholesale electricity prices, were impacted by both increasing carbon prices and rising gas prices, as the latter is the most common price setter on wholesale electricity markets.
- On infrastructure developments, in June 2021 two German transmission system operators said they intend build a 475 km network of hydrogen gas pipelines in the eastern part of Germany²⁴. The hydrogen pipeline network is part of the development of a new hydrogen hub expected to be developed from 2026. Two thirds of the total network will come from the conversion of existing natural gas infrastructure, with the remaining third being newly constructed hydrogen lines. The project is one of the 62 large scale hydrogen projects selected by the German federal government. This plan underlines the importance of conversion of traditional gas pipelines to accommodate hydrogen shipments, an important element of new hydrogen ecosystems.
- In Greece, the White Dragon green hydrogen project²⁵ is set to support the phase out 2.1GW of lignite-fired capacity by 2029. White Dragon is a 250,000 tonnes/year project that aims to use large-scale solar capacity to produce hydrogen by electrolysis.

²⁴ <https://www.globalconstructionreview.com/germany-build-475km-pipeline-network-part-8bn-hydr>

²⁵ <https://www.depa.gr/white-dragon-proposal-submitted-for-ipcei-hydrogen-important-projects-of-common-european-interest/?lang=en>

250,000 tons of hydrogen can be translated to around 8.5TWh of thermal energy, which is around 15-20% of Greece's annual energy production. Construction is set to begin in 2022, with operations set to start in 2029.

1.7 Focus on: The impact of the global gas market trends on wholesale gas prices in the EU

- As of the second quarter of 2021, a significant price increase could be observed on the European and global gas markets, with spot prices and forward contracts reaching in many cases levels not seen since the beginning of the operation of organised gas hub trade. Reasons can be found both on the demand and supply side, and many aspects of the price evolution can also be linked to recovery from the last year's price fall, amid the Covid-19 pandemic.
- In other chapters of the current report, reasons for rapid increase in European wholesale gas contracts is analysed. Recovering demand for gas amid economic rebound, seasonally low gas storage levels, decreasing gas imports from Russia, with the change in the interconnection booking practices of the Russian gas supplier, change in the timing of maintenance work on the Norwegian gas infrastructure, and decreasing number of LNG cargoes arriving to the European ports, all contributed to high European hub prices.
- This chapter focuses on global developments that impact the attractiveness of the European market for LNG cargo shipments. Over the last two decades, LNG began to play the connecting role of geographically remote regions, namely Asia, North America, Europe or other gas producers and consumers. For the liquid natural gas, the biggest market is Asia (including China, overtaking Japan in the first half of 2021, South Korea, Taiwan and India). The biggest LNG producers are Qatar, Australia, the US and Russia.
- Europe is playing a balancing market role between the biggest producers and consumers, however, LNG was seen in the EU over the last few years as increasingly important competitive alternative to pipeline gas imports. As of 2018, increasing LNG imports from the US and Russia contributed to lower wholesale gas prices on the EU markets and flexible US contracts contributed (via cancellation of a number of cargoes) to eliminate oversupply in the summer of 2020, amid looming energy demand destruction.
- The increase in gas prices in Europe, is at large extent, driven not only by supply and demand factors in Europe, but rather by other markets in the world, principally by Asia. However, there is no single factor behind the recent sharp upturn of prices, there are many different stories which add up in the current situation. In the five biggest LNG consumers in Asia (China, Japan, South Korea, Taiwan and India) LNG imports in the first eight months of 2021 were up by 47 bcm compared to the same period of 2020, which is significant in itself, given the total size of the global LNG market was around 500 bcm last year.
- Increase in China alone amounted to 20 bcm in January-August 2021 year-on-year, which was largely explained by increasing role of gas in China's power generation (partly replacing coal). In the southern and eastern part of the country, the summer of 2021 was particularly hot, resulting in cooling related demand for electricity, which had to be satisfied from gas-fired generation, given that ongoing dry period resulted in low hydro levels²⁶. In Japan, after the January price spike, buyers were increasingly building on oil-indexed contracts to avoid high-priced periods, which resulted in higher oil-indexed import volumes during several months, squeezing out contracted annual volumes. Other Asian markets, such as Taiwan, faced increasing electricity consumption over the last few years. The consumption peak in Taiwan is in August, which, coupled with a low hydro generation owing to an ongoing drought, resulted in high demand for LNG during the summer.
- Further on the demand side factors, a country in South America, Brazil, until recently not a key player in global LNG trade, also significantly impacted wholesale gas prices. Similarly to some Asian markets mentioned above, long lasting dry periods resulted in low level of hydro availability in the country, and missing power generation had to be complemented by gas-fired generation, and the gas was imported in the form of LNG. This resulted in redirection of US cargoes towards Brazil, which shipments were missing from North-Western Europe, putting a further upward pressure on the TTF and other European hubs. In January-August Brazil imported more than 6 bcm of LNG, up from only 1 bcm in the same period of 2020.
- Interesting stories also developed on the supply side of the global LNG market, largely impacting gas prices in several regions. In Qatar, the peak season of loading berth maintenance was in June and July 2021, resulting in four-year low LNG exports from the country, signalling a change in the annual maintenance calendar; in earlier years taking place in late summer/early autumn. Earlier maintenance might have been related to higher expectations on winter curve volumes. Decreasing exports from Qatar also impacted wholesale gas prices in Europe, being a principal market for Qatari LNG.
- LNG supply in 2021 so far was also impacted by some deferred maintenance works on LNG liquefaction facilities in 2020, as during spring and summer of last year, at the height of the corona-pandemic, it was not possible to carry out full scale maintenances, which had to be implemented this year. This was the case for the Russian Sakhalin LNG and Yamal LNG, and the North West Shelf in Australia.
- Further on Russian LNG, sources from the Yamal peninsula were directed to Asia, as soon as the Northern Route (the Arctic passage) became available in the summer, this year a bit later than usual, owing to ongoing wintry conditions in earlier months of 2021. This reduced further the availability of LNG in North Western Europe (mainly for France and the Netherlands). On the top of this, the time was not sufficient yet for the new Yamal 4 train to ramp up in production.

²⁶ Demand and supply side factor analysis largely builds on Bloomberg New Energy Finance's presentation (Fariah Marzuki) on 'High LNG spot prices are due to little things adding up' – 14 September 2019

- In spite of increasing number of available LNG tankers, shipping rates, which also resulted in increasing costs of delivery in sectors other than LNG, are expected to remain high in the remaining part of 2021. Forward-looking LNG charter rates kept on increasing over the last few months, as LNG portfolio managers want to ensure sufficient capacities before an eventual winter price spike on the market.
- Incremental supply crunches also occurred over the summer, for example, owing to lower feed gas deliveries to the liquefaction plant, LNG exports were slightly down from Nigeria, an important supplier to France and Spain. A train mothballed in Trinidad also resulted in less global LNG supply but this mainly impacted the Americas and Asia. The LNG export of Peru practically halved in summer 2021, owing to train outages, similarly to Algeria, having a one-month offline period (Skikda). These individual stories also added to the tightness of the global LNG market.
- In spite of the current high prices, LNG is still seen in the EU as important contributor to the security of gas supply, however, the market flexibility that benefited the European customers through many years proved to be a significant factor in higher wholesale gas price volatility in 2021.
- The competitiveness of LNG in Europe will strongly depend on all of these factors in the forthcoming winter period, as winter in Asia and availability of liquefaction capacities in the main producing countries, along with cargo shipping rates and tanker availability might all play a role on a market became fairly volatile in 2021. In the EU, local stories, such as storage levels and the pipeline imports, have of course of particular importance.

2. Wholesale gas markets

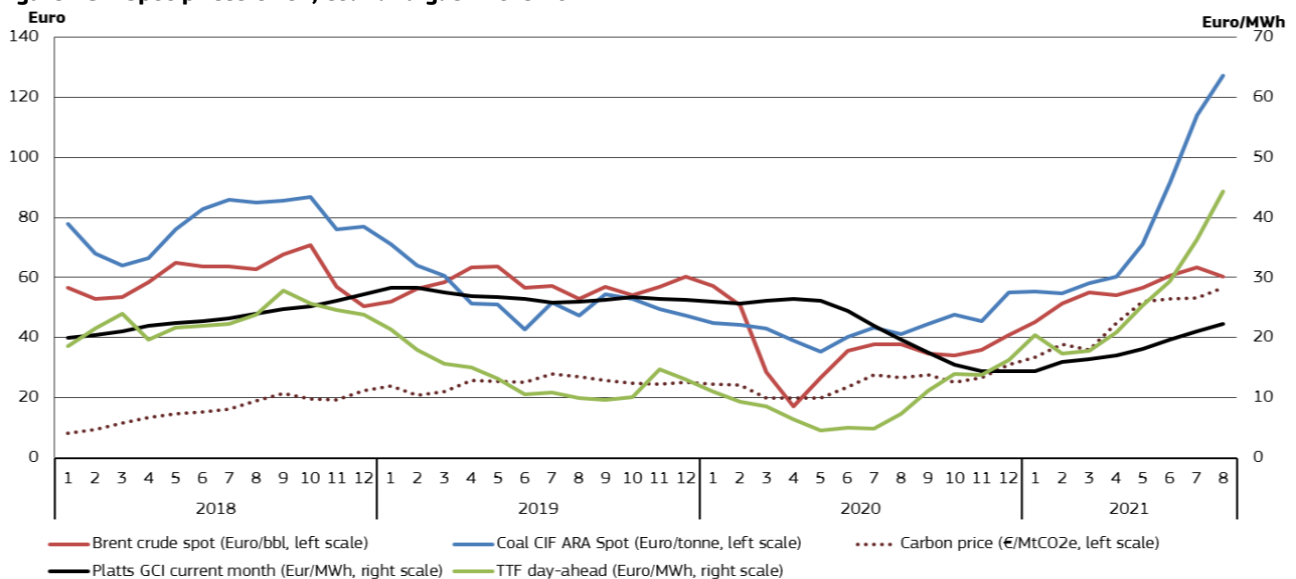
2.1 EU energy commodity markets

- The dated Brent crude oil price kept on increasing in the second quarter of 2021, up from 62 USD/bbl (53 €/bbl) at the beginning of April 2021 to 76 USD/bbl (64 €/bbl) by the end of June 2021. In the following two months oil prices, though approaching 80 USD/bbl (67 €/bbl) in the early days of July 2021, stabilized in the range of 65-75 USD/bbl (56-63 €/bbl). On the demand side of the oil market, the sudden surge stemming from re-opening the economies in the EU and putting an end to movement restrictions might still have helped to maintain upward pressure on oil prices in Q2 2021, however, in later period this impact had less importance. On the supply side, OPEC+ countries increased their production during Q2 2020, and on 18 July they managed to agree on a gradual further increase of 0.4 mbdp in each month from August to December 2021, and on the complete phase out of the original production adjustments following the April 2020 decision, by May 2022. Oil production is gradually ramping up in the US and it is expected to fully recover by 2022, which might also help in stabilizing oil prices. Over the course of Q2 2021, the discount of the year-ahead contract gradually increased compared to the spot, from 2 USD/bbl to 7 USD/bbl (1.8 €/bbl to 5 €/bbl), signaling a market expectation for correction of the spot price increase. By the end of the summer, as spot prices stabilized, this discount also decreased.
- The Dutch TTF spot gas price started the second quarter of 2021 at 19 €/MWh and underwent a spectacular increase, finishing June 2021 at 35 €/MWh. However, the upward trend of spot gas prices did not break at the end of Q2 2021, in the following months prices kept on rising, and on several trading days in September 2021 they reached 70-75 €/MWh, which is about three times as much as the average price of the last decade (around 20-25 €/MWh), and signaling historic highs since the beginning of gas trade on the European hubs.
- There were several reasons behind this unprecedented wholesale gas price rise on EU markets. First, there is an increasing demand on Asian gas markets for LNG, resulting in competitive sales prices vis-à-vis Europe, which prompted cargo redirections towards these markets. Asian price benchmarks became a strong signal to European hub prices over the last few months. LNG prices are further put under pressure from maintenance works on some facilities in big producer countries (See more in the Focus on subchapter). In Europe, as cold weather in April and May and heat waves during the summer resulted in high demand for gas, storages are being filled slower than in the previous years, increasing market tightness ahead of the winter season. Some maintenance works on pipelines (e.g. Norwegian infrastructure in Q2 2021, earlier than in the previous years), and change in the capacity booking practices on infrastructure transiting gas from Russia (less capacity bookings during the summer for the following quarter and year) also added to the tightness of gas supplies in the EU. Over the last few months, the discount of year-ahead TTF contracts to the spot increased significantly, otherwise saying the gas market is in a strong backwardation, signaling that the market anticipates a correction in the spot contracts in the following period, though current high prices are likely to stay for a few months.
- Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing a gas price linked 100% to oil, continued to increase in Q2 2021, mirroring the recovery of crude oil prices started in the second half of 2020. Normally, crude oil price changes appear in the oil-indexed contracts with a time lag of 6-9 months. GCI contracts rose from 16.4 €/MWh in March 2021 to 19.6 €/MWh in June 2021 (and rose further to 22-23 €/MWh in August and September). In Q2 2021, and further in the third quarter so far, rapidly increasing spot TTF contracts had an increasing premium over the oil-index contracts, which implied a competitive advantage of oil indexed contracts in Europe in these months. This was beneficial to some oil-indexed gas import sources (e.g. Algeria, where import flows showed a significant increase in Q2 2021 year-on-year). GCI is expected to stabilize in the forthcoming months, as the price increase in the oil market came to a halt in the third quarter of 2021. The competitiveness of oil-indexed

contracts strongly depend on the evolution of gas hub prices, but foreseeably the price advantage of oil-indexed contracts is likely to stay in the next couple of quarters.

- Spot coal prices (CIF ARA) increased steeply during the second quarter of 2021, starting month of April at 60 €/Mt, and finishing June 2021 just above 100 €/Mt. In the third quarter of 2021, coal prices continued to soar and by mid-September they reached 150 €/Mt, the highest since 2008. On the demand side, increasing demand in China and India for seaborne coal was driving the market, and in Europe soaring gas and carbon prices made coal-fired generation competitive for plants with higher combustion efficiency. On the supply side, there was tightness in several big producer countries (e.g. Colombia, South Africa, partly owing to lower production amid reviving coronavirus infections).
- Carbon prices in the second quarter of 2021, similarly to most of the energy commodities, underwent a rapid increase, up from 42 €/MtCO₂e to 56 €/MtCO₂e. However, this upward trend did not finish at the end of Q2 2021, as in mid-September carbon prices were above 60 €/MtCO₂e. Increasing carbon prices also impacted wholesale gas prices, but too steeply increasing gas prices had an adverse impact on coal-gas switching, as gas became too costly for generating power in those countries where efficient solid fuel power plants are on the grid (e.g. Germany).

Figure 23 - Spot prices of oil, coal and gas in the EU



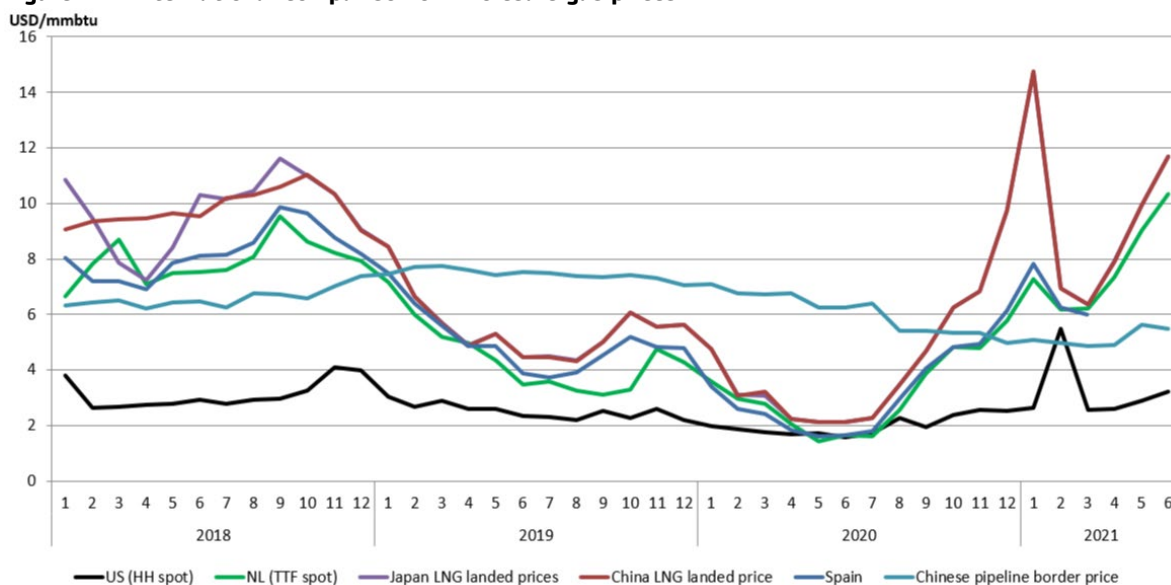
Source: S&P Global Platts

2.2 LNG and international gas markets

- Figure 24 displays the international comparison of wholesale gas prices, including hub, LNG landed and pipeline import gas prices. After price spikes in January in east Asia and in February in Texas in the United States, European (TTF), Asian (JKM) and US (Henry hub) benchmarks were more aligned at the beginning of the spring, however, as of March-April Asian prices began to increase, dragging along the TTF spot contracts, as gas demand in Asia became a global factor, strongly impacting European hub prices. Asian contracts retained a measurable premium over the TTF, indicating higher profitability for LNG producers to sell cargoes in Asia. Meanwhile, US Henry Hub, though steadily increasing over Q2 2021 and beyond, remained at relatively low levels in comparison to the other two benchmarks.
- The average Japanese LNG price was 9.9 USD/mmbtu in Q2 2021, up from 9.3 USD/mmbtu in Q1 2021, and rebounding from 2.2 USD/mmbtu in Q2 2020, implying that prices in Q2 2021 are four and half times high as they were in the trough in Q2 2020. The Japanese premium above the Dutch TTF hub was on average 1 USD/mmbtu in Q2 2021, down from 2.8 USD/mmbtu in the first quarter of 2021 (owing to the January price spike in Asia), and up from 0.4 USD/mmbtu in Q2 2020. On quarterly average, LNG import prices in China were comparable with their Japanese peers (9.9 USD/mmbtu in Q2 2021). It seems that the Asian premium to the TTF (1 USD/mmbtu) was sufficient to attract cargoes, even amid high shipment costs owing to tightness of the global freight trade.
- Chinese pipeline gas imports, presumably mostly based oil-indexed contracts, were at 5.3 USD/mmbtu in Q2 2020, having a significant price advantage vis-à-vis LNG imports (with a quarterly average price of 9.9 USD/mmbtu in Q2 2021). However, similarly to European oil-indexed gas contracts, the impact of increasing oil prices as of the second half of 2020 started to appear in import gas prices as well. High demand for LNG in East Asia is likely to ensure the competitiveness of oil-indexed contracts in the forthcoming months, as most of the recent oil price increases are probably already priced in the gas contracts.

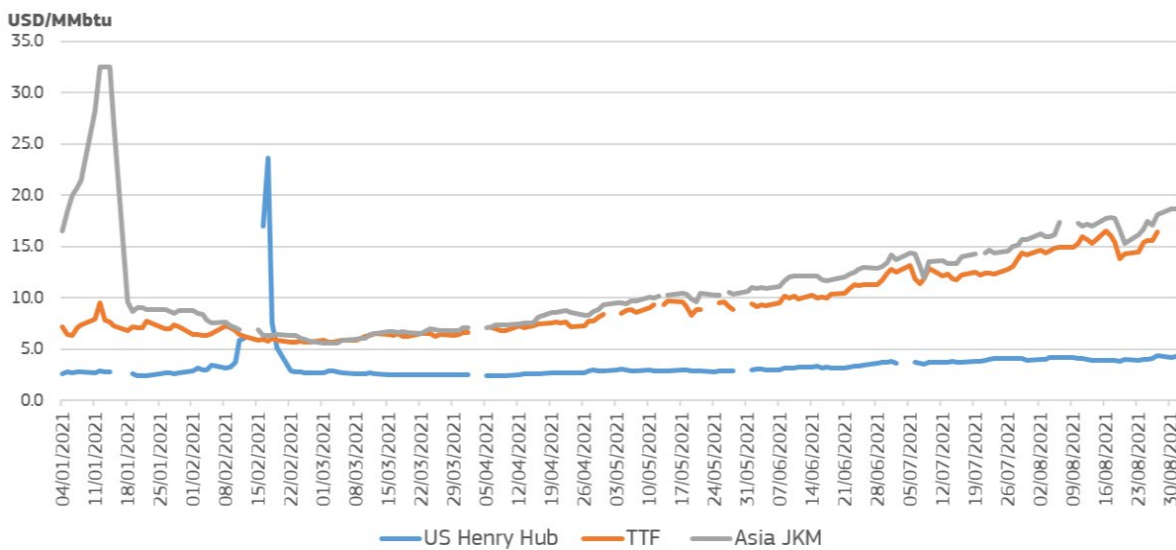
- The Henry Hub price fell to 2.9 USD/mmbtu in Q2 2021, down from 3.6 USD/mmbtu in Q1 2021 (and up from 1.7 USD/mmbtu in Q2 2020), and as Figure 25 shows, both TTF and JKM continued to increase their measurable premiums vis-à-vis Henry Hub. On quarterly average, TTF and JKM respectively had a premium over Henry Hub (6.0 USD/mmbtu and 7.0 USD/mmbtu) which provided perfect opportunities for US LNG exporters. The euro slightly appreciated against the USD in Q2 2021 (in March 2021 the exchange rate was 1.19 while in June 2021 it was 1.20), but this did not really contribute to the increasing divergence between the TTF and the Henry Hub.
- Over the course of the second quarter of 2021, in parallel with increasing absolute differentials, price ratios of international contracts mostly showed further increases. The average TTF/Henry Hub ratio was 3.1, up from 1.8 in Q1 2020 and from 1.0 in Q2 2020. The ratio of the Japanese LNG price and US Henry Hub was 3.4 in Q2 2021, up from 2.6 in Q1 2021 and from 1.3 in Q2 2020. The average price ratio of the Japanese LNG prices and the TTF was 1.1 in Q2 2021, slightly down from 1.4 in Q1 2020, but up from 1.3 in Q2 2020.
- In absolute terms, in Q2 2021 the TTF showed an increasing premium to the Henry hub (6.0 USD/mmbtu, after 3.0 USD/mmbtu in Q1 2021), whereas the premium of Japanese LNG prices to TTF decreased in Q2 2021 from 2.8 USD/mmbtu to 1.0 USD/mmbtu. During the same period premium of Japanese LNG prices to Henry Hub rose from 5.8 USD/mmbtu to 7.0 USD/mmbtu, implying better profitability (even if higher shipment costs are counted) of US LNG exports to Asia compared to Europe.
- In the second quarter of 2021, TTF averaged at 8.9 USD/mmbtu (25.2 €/MWh), up from 6.6 USD/mmbtu (18.6 €/MWh) in Q1 2020 and, after 1.7 USD/mmbtu (5.3 €/MWh) in Q2 2020. The average German border price in Q2 2021 was at lower than the TTF (6.3 USD/mmbtu or 17.8 €/MWh), showing that this time the impact of still existing oil-indexed contracts in the German gas import mix resulted in less volatility compared to the European hub prices.
- In the second quarter of 2021, spot prices averaged 8.9 USD/mmbtu in the Netherlands, 8.5 USD/mmbtu in Spain, and 9.9 USD/mmbtu in China and Japan.
- The JCC (Japanese Crude Cocktail) contracts reached 8.6 USD/mmbtu in the second quarter of 2021 on average, equalling the average of Q1 2021 and down from 9.7 USD/mmbtu in Q2 2020, and were still lower than Japanese LNG import prices (9.9 USD/mmbtu), and slightly lower than the TTF (8.9 USD/mmbtu).

Figure 24 - International comparison of wholesale gas prices



Sources: S&P Global Platts, Refinitiv, BAFA, CEIC

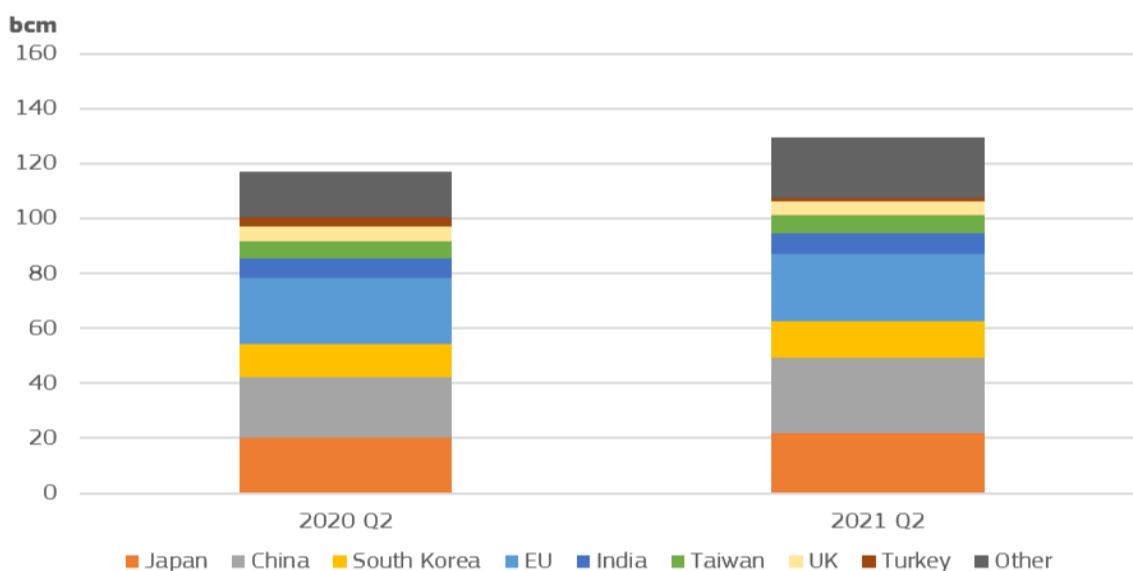
Figure 25 – Daily average prices on the TTF (Dutch), the US Henry hub and the JKM Asian reference index



Sources: S&P Global Platts

- The next two charts show the key actors of global LNG trade on importer (consumer) and exporter (producer) side. In Q2 2021 China took over the title of biggest LNG importer in the world from Japan (taking into account the one-year backward looking cumulative data), ensuring around 28 bcm of imports out of the total estimated 130 bcm market. The EU (as 27 countries) had a quarterly LNG import of 24 bcm, followed by Japan (practically the second market as individual country, with an estimated quarterly import of 22 bcm), South Korea (13 bcm), India (8 bcm), Taiwan (constituting a separate market, with an import volume of 7 bcm), the United Kingdom (5 bcm) and Turkey (1.5 bcm). Compared to the second quarter of 2020, a significant increase could be observed in China (28%), in South Korea and Taiwan (both 9%) and in Japan and India (both 8%), whereas EU LNG imports only rose slightly (by 1%) showing how demand in Asia soaked up LNG on the global market. Europe only plays the role of global balancing market between producers and the principal Asian customers, providing place for eliminating global supply and demand side imbalances.

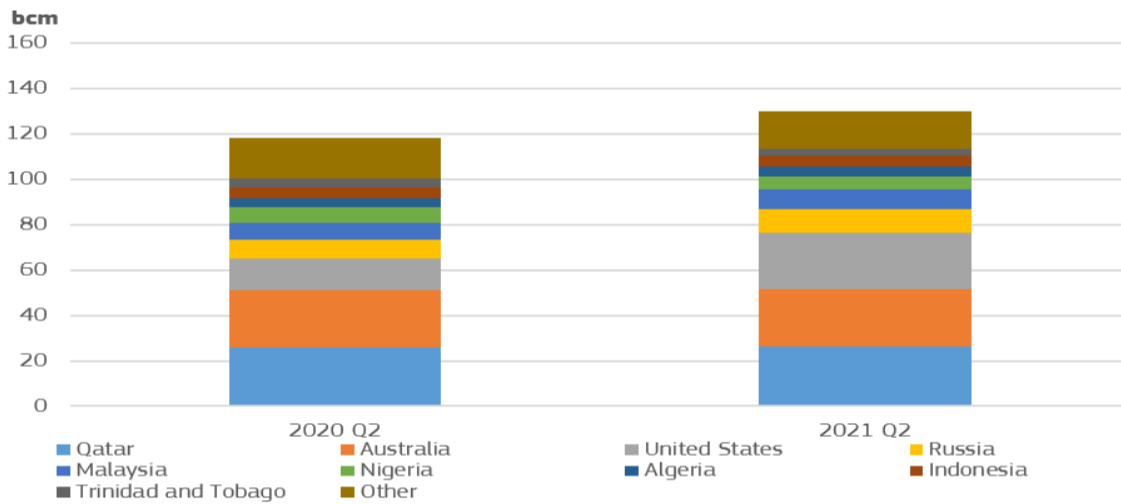
Figure 26 – LNG imports in the main consumer markets in the second quarters of 2020 and 2021



Source: Refinitiv tracking of LNG vessels. Import data are based on cargo arrival dates, therefore total amount of global imports might differ from global export numbers

- On the exporter side, Qatar has played the leading role in global LNG production, exporting 26 bcm LNG in Q2 2021. However, Australia came close to the second place in the same period, trailing Qatar only by 0.8 bcm of production. The United States were the third most important exporter, supplying almost 25 bcm in Q2 2021. Russia, mainly focussing on pipeline gas business in earlier periods, came to the fourth place with exports of 11 bcm, ahead of Malaysia (9 bcm), Nigeria (6 bcm), Indonesia (5 bcm) and Algeria (4 bcm) and Trinidad and Tobago (3 bcm).

Figure 27 – LNG exports in the main consumer markets in the second quarters of 2020 and 2021



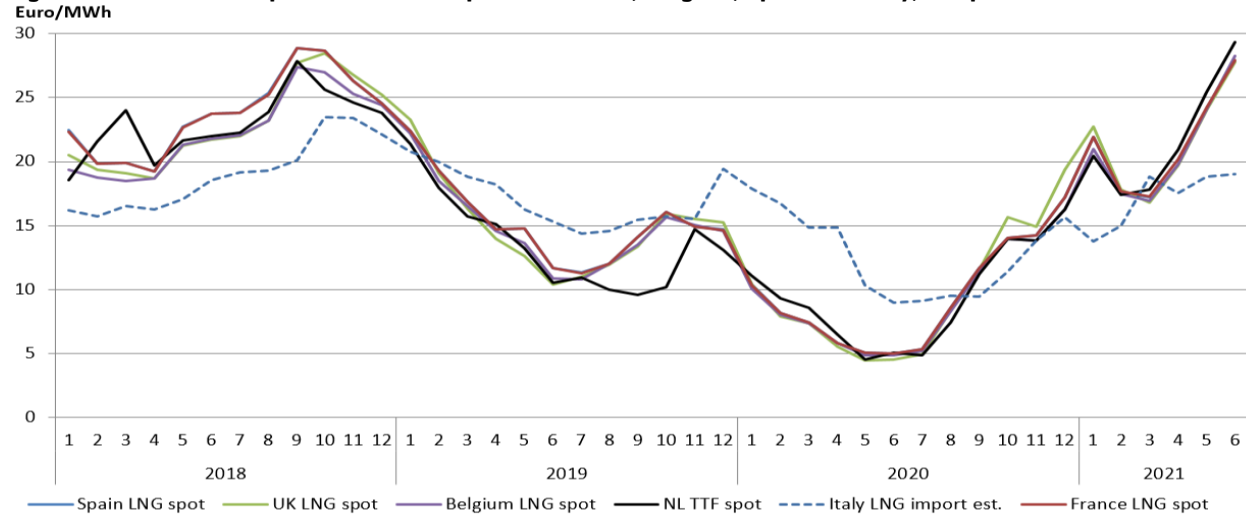
Source: Refinitiv tracking of LNG vessels. Export data are based on cargo departure dates, therefore total amount of global exports might differ from global import numbers

2.3 European gas markets

2.3.1 LNG contracts in Europe

- Figure 28 displays the evolution of spot LNG prices paid in the UK, Spain, France, Belgium and Italy, compared with the TTF spot benchmark. With the exception of Italy, where LNG prices are estimated from commercial statistics (Eurostat COMEXT), using the imported values and volumes of LNG, other markets represent landed prices based on vessel movements (from Refinitiv data).
- In the second quarter of 2021, hub prices and hub-based import price contracts in western Europe showed higher divergence than in the previous quarter, as the differentials between these prices were around 6.7 €/MWh (between 18.7 €/MWh and 25.2 €/MWh), implying that differentials increased amid the general price increase as well. Taking out the Italian COMEXT derived average price, the difference was only 1.4 €/MWh, which was however, also slightly higher than in the previous quarter (0.7 €/MWh). The Q2 2021 quarterly average prices showed a significant increase of 16-36% compared to the previous quarter, reflecting the continued price upturn on wholesale gas markets and import contracts. In June 2021 hub and LNG contract prices were close to the peaks in autumn 2018. In year-on-year comparison, most contracts showed more than threefold increases, as Q2 2020 marked the trough and some cases all-time low prices for the European contracts. However, comparing to the pre-Covid lockdown period, Q2 2019, prices showed an increase of 75-90% (with the exception of Italy, where commercial statistics will reflect recent increases probably in later periods), implying that current prices are significantly higher even compared to 'normal' times.

Figure 28 - Price developments of LNG imports in the UK, Belgium, Spain and Italy, compared to the TTF benchmark

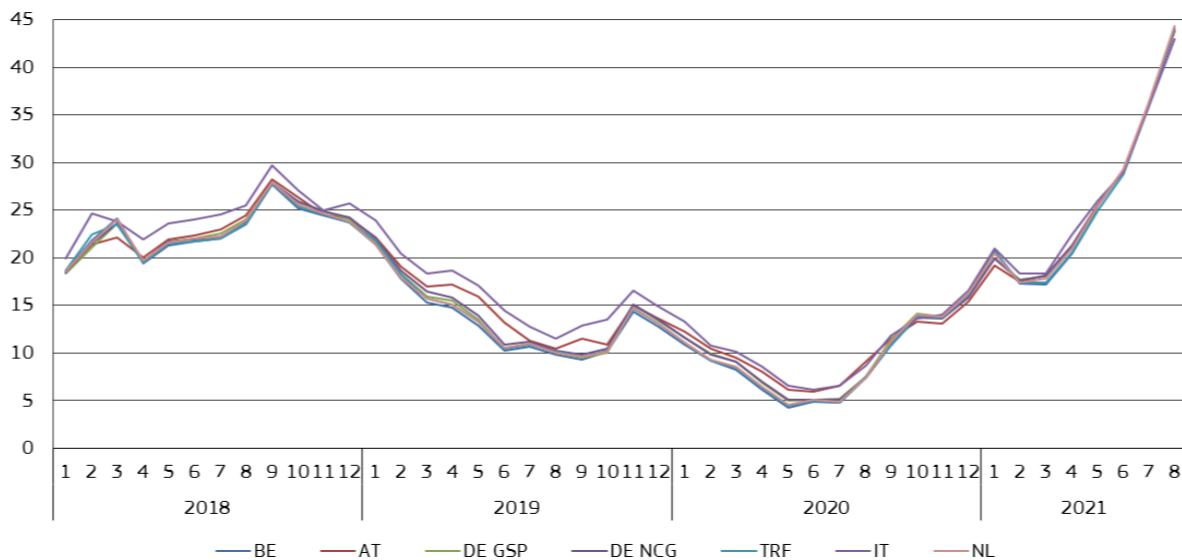


Note: Landed prices for LNG. Source: S&P Global Platts, Refinitiv, European Commission estimates based on Eurostat COMEXT data, retrieved on 15 September 2021.

2.3.2 Wholesale price developments in the EU

- European hub prices were in a narrow range, averaging around 24.7–25.9 €/MWh in the second quarter of 2021, measurably higher than in the previous quarter, Q1 2021 (18.2-19.5 €/MWh), adding around 31-39% to the price level just within a quarter's time, which shows a generally increasing price trend. Hub prices reached the highest since Q4 2018, and in year-on-year comparison they rose to three to five times as high, as Q2 2020 (which was the trough of demand destruction driven gas price fall) they averaged around 4.9-7.1 €/MWh. The average TTF hub price was 25.1 €/MWh in Q2 2021, more than four times as much as in Q2 2020. Comparing to Q2 2019, the observed prices were up by 50-110%, signalling that current prices are measurably higher than two years before.
- In the second quarter of 2021 strong demand for gas in Asia resulted in an increasing competition for LNG. On the top of this, maintenance works brought forward in the calendar (e.g. in Norway) and cold spells during springtime made refilling of gas storages slower, increasing demand for gas until the end of the injection season, and heading to summer heat waves also resulted in additional demand for gas, pushing up wholesale prices on the European hubs. During summer of 2021 less than expected interconnector booking from the Russian gas supplier, implying decreasing inflows in the forthcoming period, also added to the tightness of gas supply.

Figure 29 - Wholesale day-ahead gas prices on gas hubs in the EU
Euro/MWh

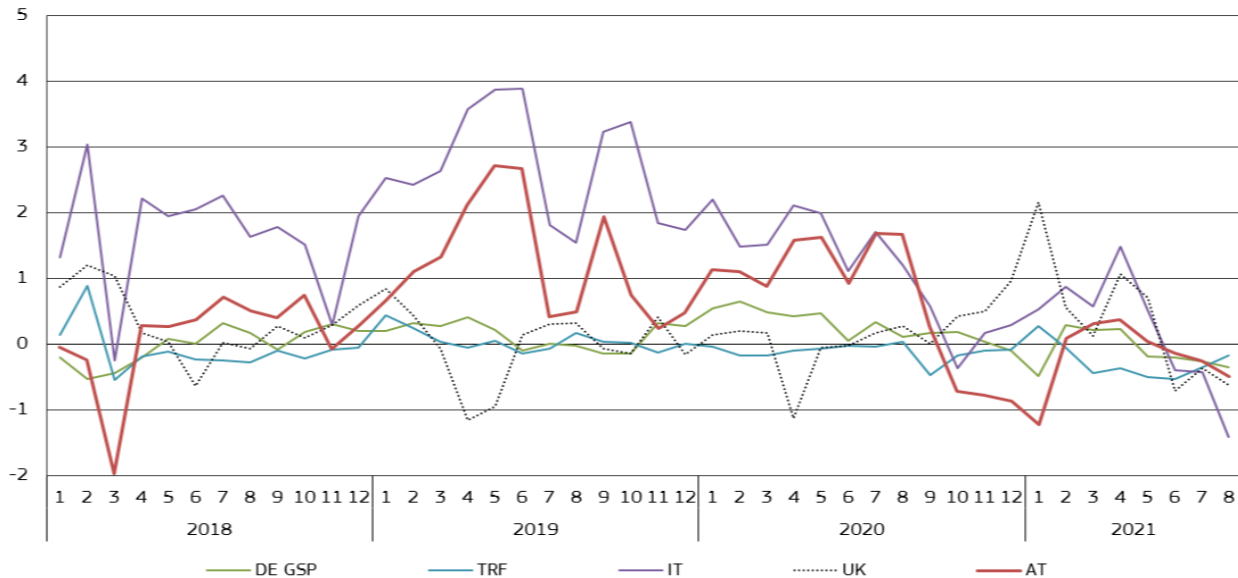


Source: S&P Global Platts

- As Figure 30 and Figure 31 show, the French TRF market was in a slight discount to TTF market during most of the time in the second quarter of 2021, even if during colder periods in April and May, with lower wind availability and even during the maintenance period of some LNG facilities in France. It seems that TRF was less impacted by decreasing inflows from Norway and less LNG availability than the TTF peer during Q2 2021.
- The German Gaspool also remained well-aligned with the TTF in Q2 2021, and was mainly impacted by weather conditions (cold weather in April and May), an unplanned outage at Mallnow interconnector mid-April (impacting Russian inflows), and later on, increasing carbon prices, lower than expected inflows from Norway and low storage levels.
- The Austrian hub showed a slight premium to the TTF in April 2021, which by June turned to discount. The premium in April might have been related to the cold weather and intensive recourse to storage withdrawals, and the uncertainties around booking volumes for Russian gas. Later in the quarter, storage levels and inflow expectations from Russia also played an important role, but discount to the TTF in June might be related to less exposure to LNG and inflows from Norway.
- In Italy, the PSV hub price developed a premium of 2-3 €/MWh on some trading days vis-à-vis TTF during April 2021, which was mainly due to a series of cold spells in the country. Demand for gas was reinforced by the mandatory storage injection rules (18-20% filling rates for April, 38-44% for May, higher than 50% in June). Later in the quarter, prices were mainly impacted by infrastructure events (e.g. outage of the TAP between 17 and 21 May, outages of LNG regasification terminals with significant capacities). However, it seems that the new TAP route helped in reducing market volatility in 2021 so far, compared with earlier years.

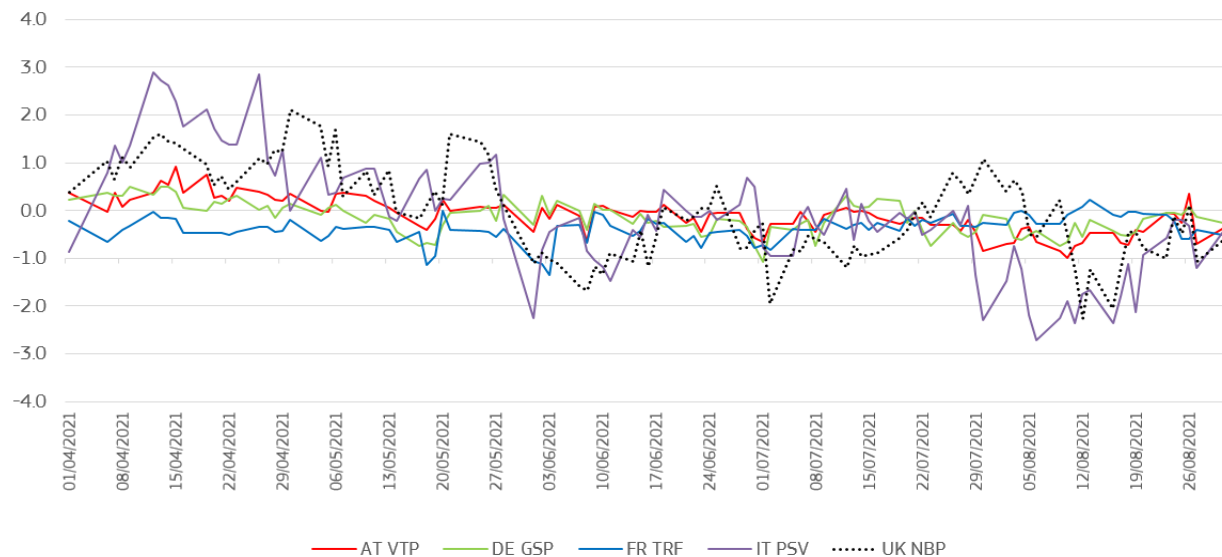
- In April and May 2021, the NBP hub price was during most of the time above the TTF benchmark, owing to colder than usual weather conditions, low LNG berthing, extra demand for gas inflows from the continent, and maintenance works on Norwegian infrastructure, also impacting gas flows to the UK. Later in the quarter, gas prices were up in the UK and on the continent as well, impacted by increasing carbon prices, low storage levels in continental Europe and price premium of the Asian gas markets.

Figure 30 - Premium of monthly average wholesale day-ahead gas prices at selected hubs compared to TTF Euro/MWh



Source: S&P Global Platts, European Commission computations

Figure 31 - Premium of daily average wholesale day-ahead gas prices at selected hubs compared to TTF Euro/MWh

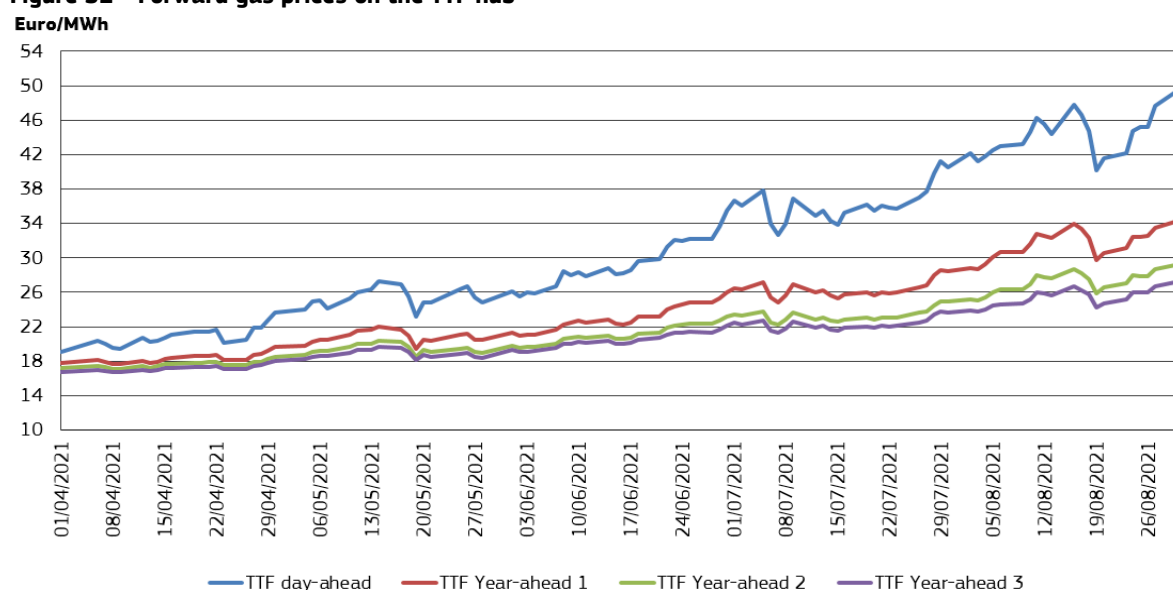


Source: S&P Global Platts, European Commission computations

- Figure 32 looks at the development of forward prices of one-year, two-year and three-year ahead contracts in comparison to the development of the day-ahead price on the Dutch TTF.
- Daily spot prices on the TTF hub underwent a significant increase in Q2 2021, starting the quarter at 19 €/MWh and finishing at 35 €/MWh. By mid-September, spot prices rose even further, reaching on some trading days 70-75 €/MWh. However, the steep increase in the spot contract, albeit also rising, was not closely mirrored by forward contracts. On 1 April, the year-ahead, two-year ahead and three year-ahead contracts were respectively 17.7€/MWh, 16.2€/MWh and 16.7€/MWh, whereas on 30 June these three contracts reached 26 €/MWh, 23.2 €/MWh and 22.1 €/MWh. The discount of the year-ahead contract to the spot (market in backwardation) grew from 1.4 €/MWh to 9.4 €/MWh during Q2 2021, and by the end of August 2021 this difference rose to

15.4 €/MWh, implying that the market, though forward prices are also rising, anticipates a correction of the current price level, probably after the end of the 2021/22 winter heating season.

Figure 32 - Forward gas prices on the TTF hub

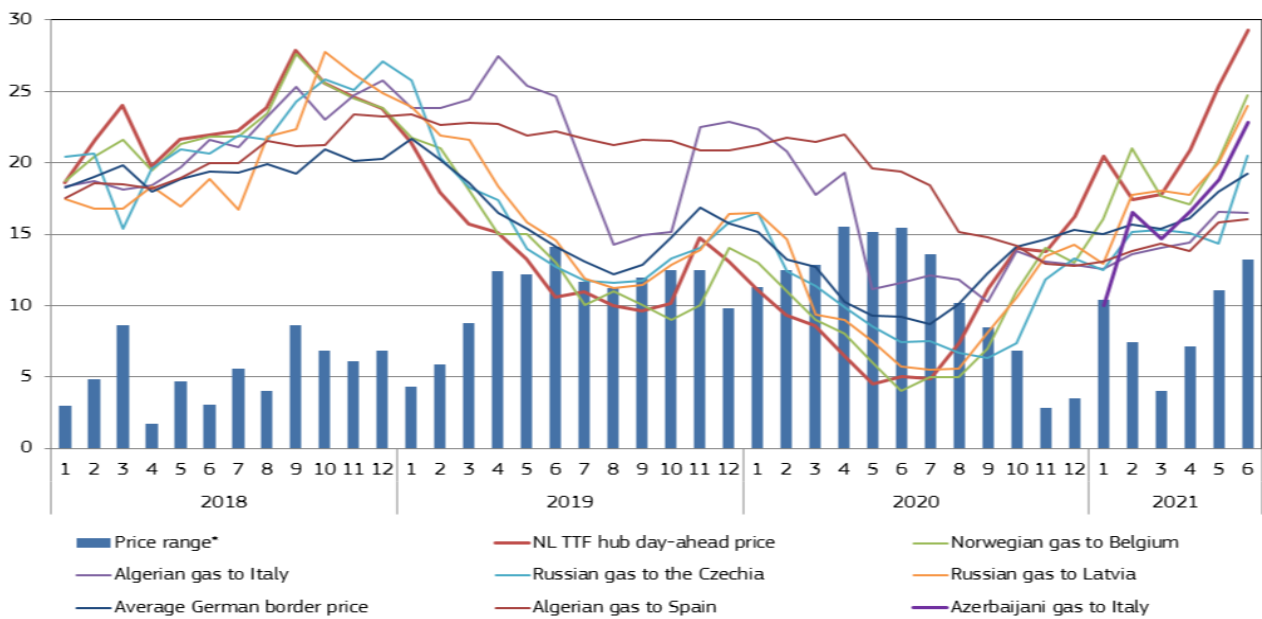


Source: S&P Global Platts

2.3.3. Prices of different pipeline contracts for gas in the EU

- Figure 33 compares a selection of estimated border prices of gas deliveries from the main exporters to the EU: Russia, Norway, Algeria and Azerbaijan. For comparison, the evolution of the day-ahead prices on the Dutch TTF hub is also presented on the chart.
- In the second quarter of 2021, the estimated Algerian pipeline import price in Spain was 15.2 €/MWh, up by 11% compared to the previous quarter (13.7€/MWh), but was down by 25% compared to Q2 2020. The Algerian contract clearly reflects the time-lagged impact of recovering crude oil prices as of mid-2020. In Q2 2021, the average estimated Algerian import price in Spain had a discount of almost 9 €/MWh to the Spanish LNG import price, providing a competitive advantage to Algerian imports, more than tripling in Q2 2021 year-on-year in Spain.
- In the second quarter of 2021 Algerian gas import price in Italy (15.8 €/MWh) was similar to that in Spain. In quarter-on-quarter comparison, Algerian import price in Italy was up by 18%, and year-on-year it rose by 13% in Q2 2021. Probably owing to more competitive pricing vis-à-vis other import sources in Italy, pipeline gas imports from Algeria was up by 238% in Q2 2021 year-on-year (See Chapter 1.3 Imports). For the future, the current advantage of oil-indexed contracts is likely to remain only as long as spot gas prices are at current high levels, as increase in oil prices as of mid-2020 is probably mostly priced in the oil-indexed contracts.
- Russian gas imports prices in both Czechia and Latvia continued to increase in Q2 2021 and were respectively up by 16% and 27% compared to the previous quarter, whereas year-on-year they rose by 94% and 178%. This implies a much closer mirroring of European hub prices compared to the oil priced contracts, implying that the latter must have had a minimal share in the pricing formulae. Latvian import price of Russian gas still had a premium to import prices in Czechia (20.6 €/MWh vs. 16.7 €/MWh) in Q2 2021.
- Prices of European gas contracts showed signs of divergence in Q2 2021, as the difference between the cheapest and most expensive contract rose from 4 €/MWh in March to 13.6 €/MWh in June 2021. In Q2 2021, the TTF spot prices proved to be the more expensive compared to the observed import contracts, as it takes some time till spot prices filter in the import contract pricing. Without TTF, price differential would only have been around 8-9 €/MWh in June 2021.
- Hub-based contracts and hub prices themselves continued their upturn in the second quarter of 2021. Reported German border prices also increased, similarly to most of the hub-based contracts, however the increase was less intense than in the case of hub prices, probably owing to the existence of oil-indexation in some import sources to Germany.

Figure 33 - Comparison of EU wholesale gas price estimations
Euro/MWh



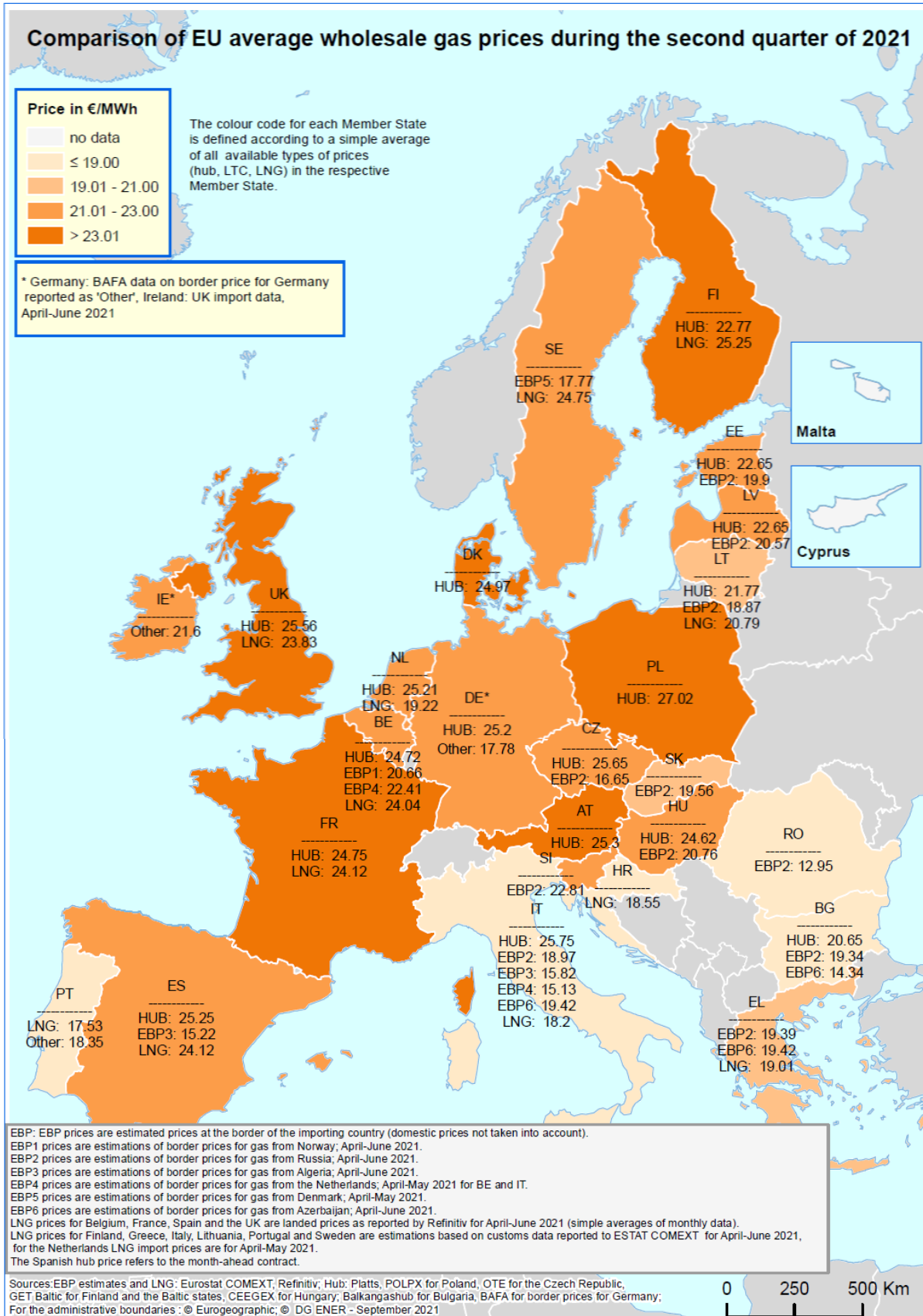
Source: Eurostat COMEXT and European Commission estimations, BAFA, S&P Global Platts

*The difference between the highest and lowest price depicted on the graph

Note: Border prices are estimations of prices of piped gas imports paid at the border of the importing country, based on information collected by customs agencies, and are deemed to be representative of long-term contracts.

- Map 1 on the next page shows the different hub prices, estimated pipeline and LNG import prices in most of the European countries, giving an indication to wholesale gas prices in the given country in the second quarter of 2021.

Map 1 - Comparison of EU wholesale gas prices in the second quarter of 2021



Note: Border prices are estimations of prices of piped gas imports paid at the border of the importing country, based on information collected by customs agencies, and are deemed to be representative of long-term gas contracts.

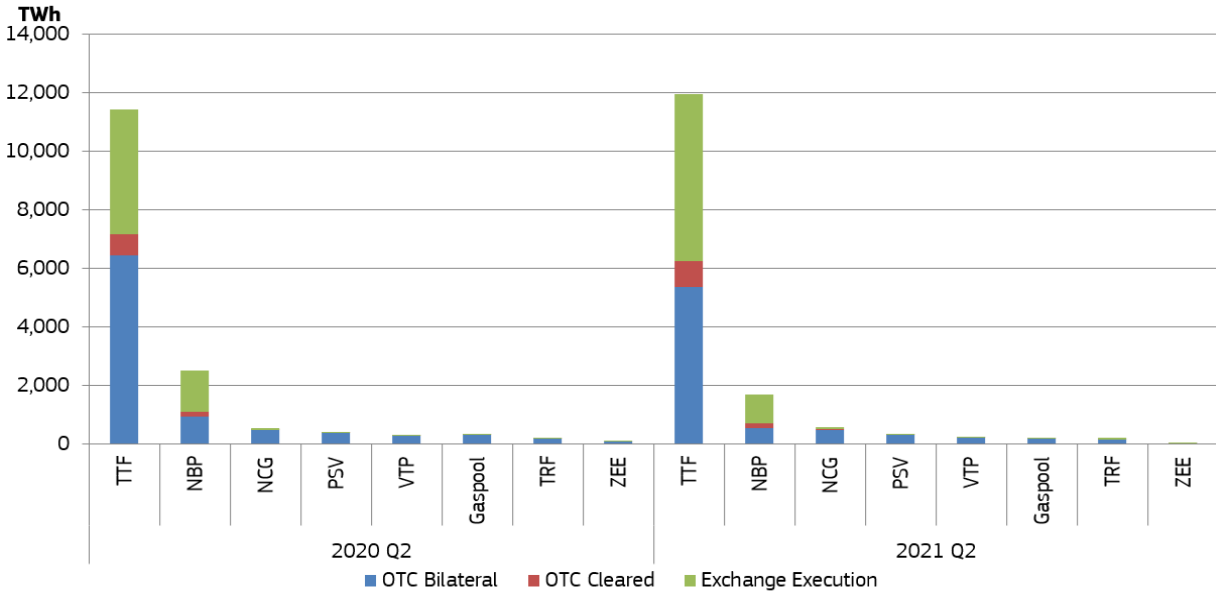
2.3.4. Gas trade on the EU hubs

- As Figure 34 shows, liquidity on the main European gas hubs decreased year-on-year in the second quarter of 2021 by 4%, after a decrease of 13% year-on-year in Q1 2021 and an increase of 10% in Q4 2020. In Q2 2021, the total traded volume amounted to around 15 201 TWh (equivalent to around 1 410 bcm and in monetary terms representing €383 billion²⁷). The Q2 2021 traded volume was around 22 times more than the gas consumption in the six Member States²⁸ covered by the analysis in April-June 2021. Comparing to the EU as a whole, traded volume in Q2 2021 represents 15 times the total EU-27 gas consumption in this period.
- Traded volumes in Q2 2021 fell on most of the observed trading hubs in Europe in year-on-year comparison, with the exception of TTF and NGC. On the most liquid hub, the TTF, traded volumes rose by 5% year-on-year. Although traded volumes were slightly up (by 3%) on NGC, the two German hubs (Gaspool and NGC) together underwent a decrease of 13% in traded volumes during the same period. In Italy (PSV) the volume went down by 22%, and on the VTP hub in Austria traded volumes fell by 19%. On the French TRF traded volumes fell by 4% in Q2 2021. The steepest fall in traded volumes could be observed on the Belgian Zeebrugge hub (by 73%) in Q2 2021 year-on-year, and total volumes amounted only to 22 TWh (whereas on the TTF volumes reached 11 975 TWh). At the same time, traded volumes on British NBP hub, which was still the second biggest hub on the broader European market, continued to fall, by 32% compared to Q2 2020.
- As the year-on-year change in traded volumes on the TTF hub rose by 5% in Q2 2020, whereas traded volumes on overall observed European markets fell by 4%, the share of TTF in the total European gas trade increased further (in Q2 2021 amounting to 79%, whereas a year before it was only 72%). If looking at only the EU countries, its share is even bigger, 89%. TTF has emerged to a liquid continental benchmark, having the advantage of euro-denomination, and benefiting from its good connection to various supply sources and access to seasonal storage as well. On the other hand, decrease on the NBP hub signalled a further shift from once Europe's most liquid market. The traded volume in Q2 2021 fell by 32% compared to the same period of 2020, and the share of NBP in Q2 2021 fell to 11% in the total European observed trade, down from 16% in Q2 2020.
- Other markets had lower shares: Germany (NGC and Gaspool together) had a share of 5.1%, while the Italian PSV only had 1.9%, whereas VTP had a share of 1.6%, TRF had a share of 1.4% and Zeebrugge had only a minor share in the European gas trade (0.1%) in Q2 2021.
- Net gas imports was up by 7% and LNG imports was also slightly up by 1% year-on-year in the EU in Q2 2021, consumption of gas went up by almost 19%. Even increasing consumption and imports were not sufficient to boost traded volumes on the most liquid European hubs. Trading volumes were mainly driven by near-curve contracts (spot and month-ahead), whereas trade on the far end of the curve decreased further. The near end of the curve was also supported by increasing need for gas in power generation.
- The share of exchange executed contracts on the Dutch TTF hub was 48% in Q2 2021, which was the highest among the observed EU countries, and was up by 11 percentage points compared to Q2 2020. On the French TRF the share of exchange executed contracts reached 26% in Q2 2021 (up by 7 percentage points), while on the two German hubs together it amounted to 16% (up by 4 percentage points). On the VTP hub in Austria this share was 18%, up from 14% in the same period of 2020. On Zeebrugge, the share of exchange-executed contracts was much lower, only 3%, whereas it was the lowest on the Italian PSV, amounting to barely 1%. On the NBP hub in the UK, the share of exchange trade was still the highest among all observed markets, amounting to 59% in Q2 2021, even up by 2 percentage points compared to Q2 2020.

²⁷ Assuming that all trade was carried out on the quarterly average spot price of the TTF hub

²⁸ Netherlands, Germany, France, Italy, Belgium, Austria The ratio of the quarterly traded volume and gas consumption can show a big volatility across different quarters, as gas consumption has a high seasonality, whereas gas trade depends on market factors, which are albeit linked to consumption but have less seasonality.

Figure 34 - Traded volumes on the main European gas hubs in the second quarters of 2020 and 2021

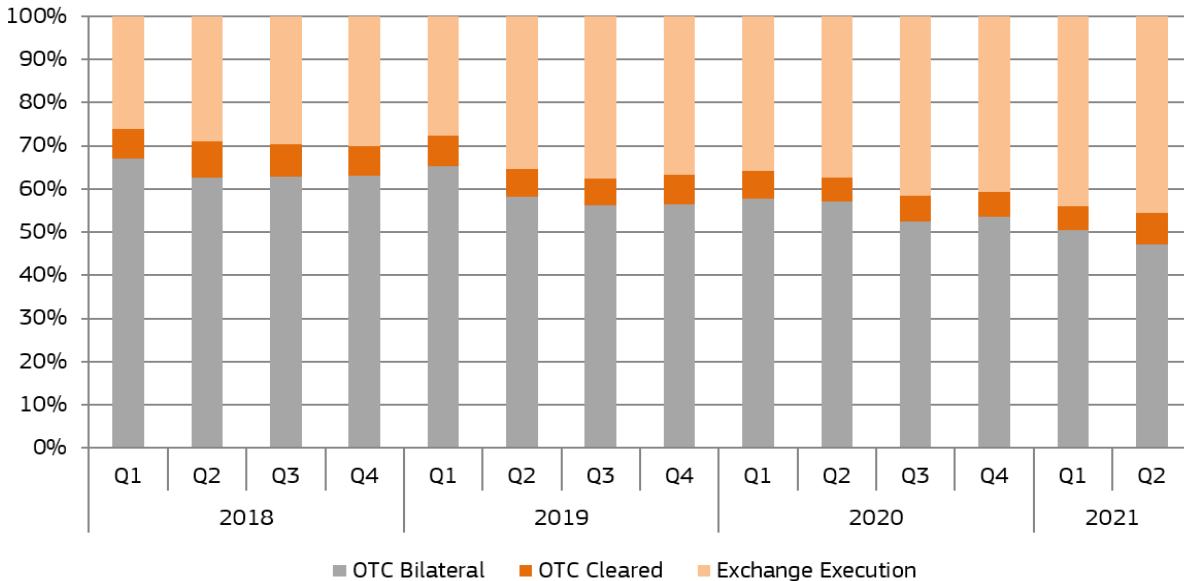


The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: TRF (Trading Region France); Italy: PSV (Punto di Scambio Virtuale); Austria: Virtual Trading Point (VTP); Belgium: Zeebrugge beach; UK: NBP (National Balancing Point)

Source: Trayport Euro Commodities Market Dynamics Report

- On the European hubs as whole, in Q2 2021 47% of the total trade was OTC bilateral, 7% was OTC cleared, whereas the share of exchange-executed contracts was a 46%. The share of exchange-executed contracts increased by 8 percentage points year-on-year in Q2 2021, whereas the share of OTC bilateral went down by almost 10 percentage points, and that of OTC cleared went up by 2 percentage points. The share of exchange executed volumes (46%) was the highest in the last six years, reinforcing the trend of shift towards exchanges from the OTC market.
- Amid the general decrease in traded volumes (4% in Q2 2021 year-on-year), exchange executed volumes managed to go against the trend, by growing 17% year-on-year on the observed European markets. In the same period, the total OTC traded volume (bilateral and cleared together) fell by a similar extent, 17%. This underlines the increasing importance of exchange-executed contracts in the gas trade on the major European hubs.

Figure 35 - Share of traded volumes on the main European gas hubs

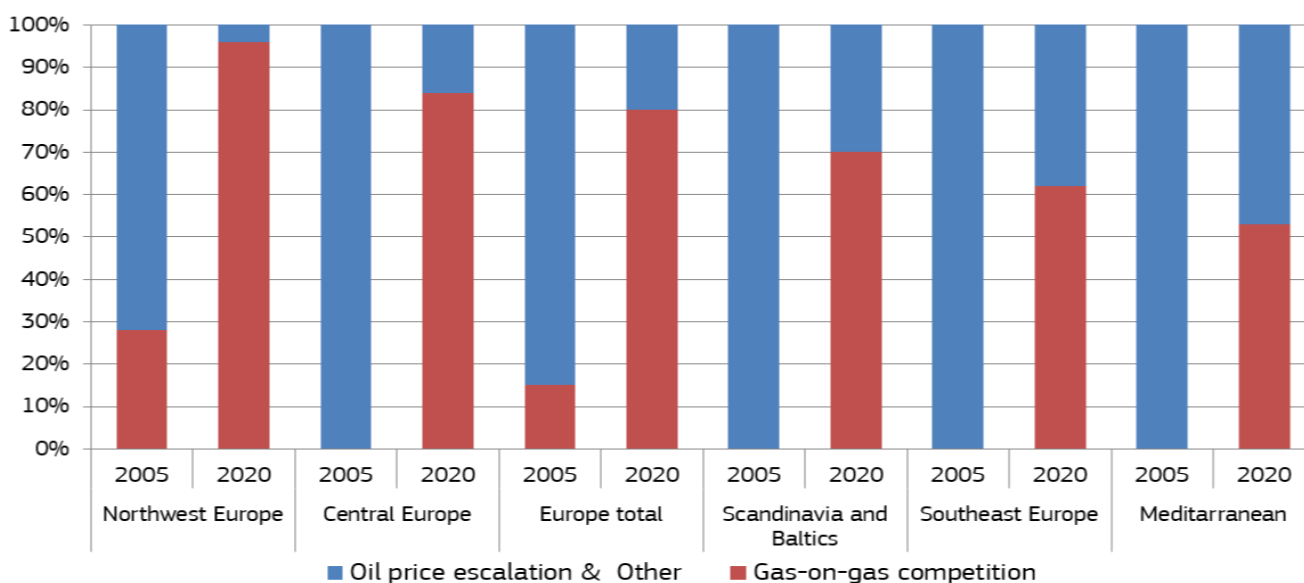


The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Exchange Gaz); Italy: PSV (Punto di Scambio Virtuale); Belgium: Zeebrugge beach, Austria: Virtual Trading Point (VTP); UK: NBP (National Balancing Point).

Source: Trayport Euro Commodities Market Dynamics Report

- Figure 36 and Figure 37 provide a look at the evolution of gas price formation mechanisms over time and/or across regions²⁹. In Europe, the share of gas-on-gas competition (hub-based pricing) increased from 15% to 80% between 2005 and 2020. However, there are big regional differences behind the European average.
- In North-Western Europe (Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, UK) gas-on-gas competition is now almost exclusive, its share was 96% in the total gas contracts (measured by consumption) in 2020, up from 28% in 2005. In other parts of Europe, gas-on-gas competition practically did not exist in 2005, whereas in 2020 its share was 84% in Central Europe (Austria, Czechia, Hungary, Poland, Slovakia, Switzerland), 70% in Scandinavia and the Baltics as well (Estonia, Finland, Latvia, Lithuania, Norway, Sweden) and 62% in Southeast Europe (Bosnia, Bulgaria, Croatia, North Macedonia, Romania, Serbia, Slovenia). In the Mediterranean region (Greece, Italy, Portugal, Spain, Turkey) gas-on-gas competition still had the lowest share, however, for the first time more than half of the total gas consumption could be linked to gas-on-gas, amounting to around 53% in 2020.
- In parallel with the increasing share of gas-on-gas competition, the share of oil-price escalation (oil-indexed contracts) decreased, as well as other forms of price formation, such as bilateral monopolies or regulated contracts (such as regulation of cost of service, political and social regulation, etc.) between 2005 and 2020.
- Gas-on-gas competition had a share of 49% in the world on average in 2020, and oil price escalation represented 19%, whereas bilateral monopolies and diverse forms of price regulation had the remaining share (32%). With its share of gas-to-gas competition of 80%, Europe is the second region in the world behind North America regarding the penetration of hub-based pricing. In other regions, such as Asia, oil price escalation is still predominant, with its share of 63% in 2020.
- In the Middle East, Africa, Russia and other countries of the former Soviet-Union, Latin-America price regulation was still the most important contract form in 2020.

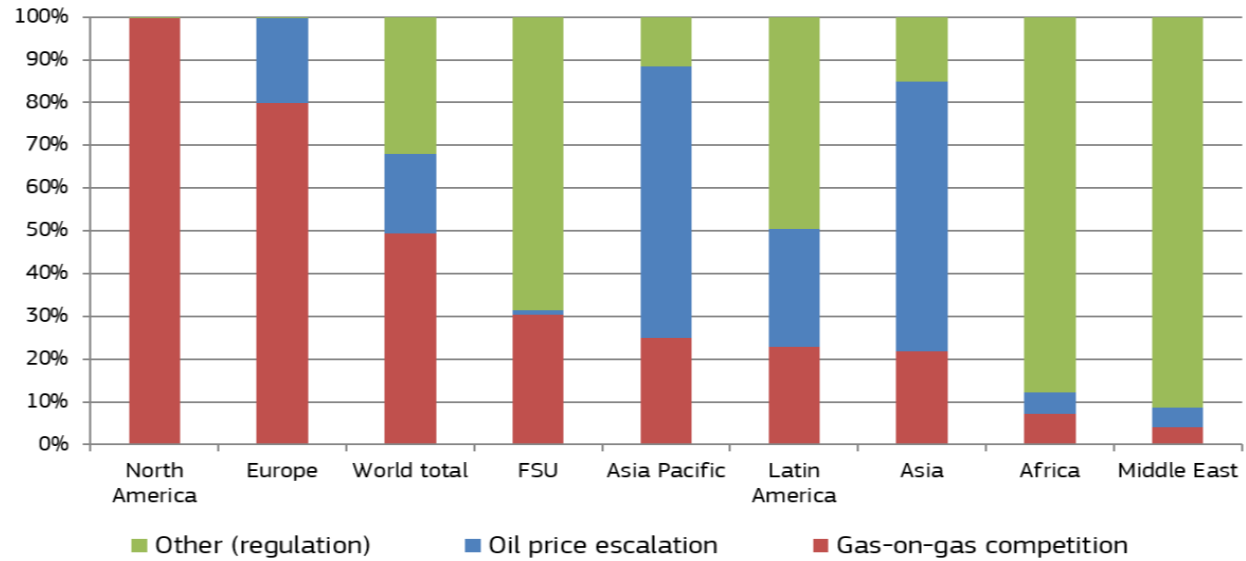
Figure 36 - The share of gas-on-gas competition and oil price indexation (escalation) in gas contracts in different European regions



Source: 2021 edition of the Wholesale gas price survey, International Gas Union

²⁹ Based on statistics from the 2021 edition of the Wholesale gas price survey of the International Gas Union. Regional statistical data are based on the country classification of the survey.

Figure 37 - The share of gas-on-gas competition and oil-price escalation in different global regions in 2020



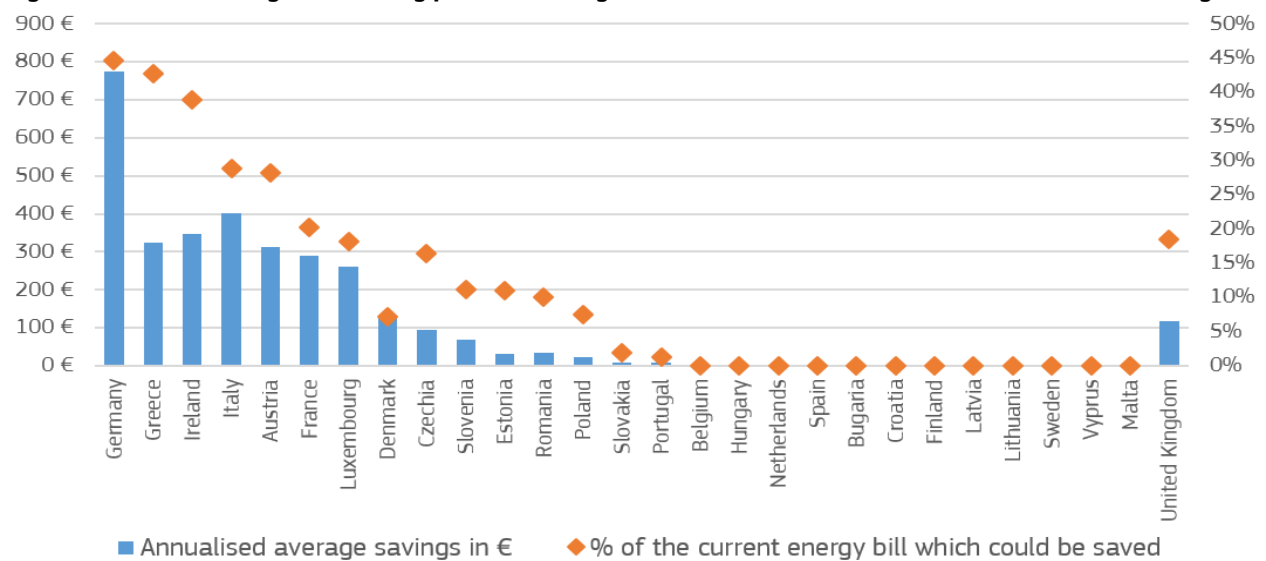
Source: 2021 edition of the Wholesale gas price survey, International Gas Union

3. Retail gas markets in the EU and outside Europe

3.1 Savings from switching for residential gas customers

- The next chart shows the estimated annualised average savings in euro and percent of the current energy bill available to typical households who switched away from their local by-default contract to the cheapest offer available in August 2021. Prices in capital cities were used as a proxy to assess prices at the national level.
- In August 2021 in absolute terms, German households could have the highest annualised savings (€775, or 45%), had they switched from their incumbent utility to the most competitive offer available. On the other hand, households in Portugal could have the lowest annualised savings, amounting to 1.9% or €7 if they chose the most competitive offer.

Figure 38 – Annualised gas bill saving potential in August 2021 in the EU Member States and the United Kingdom

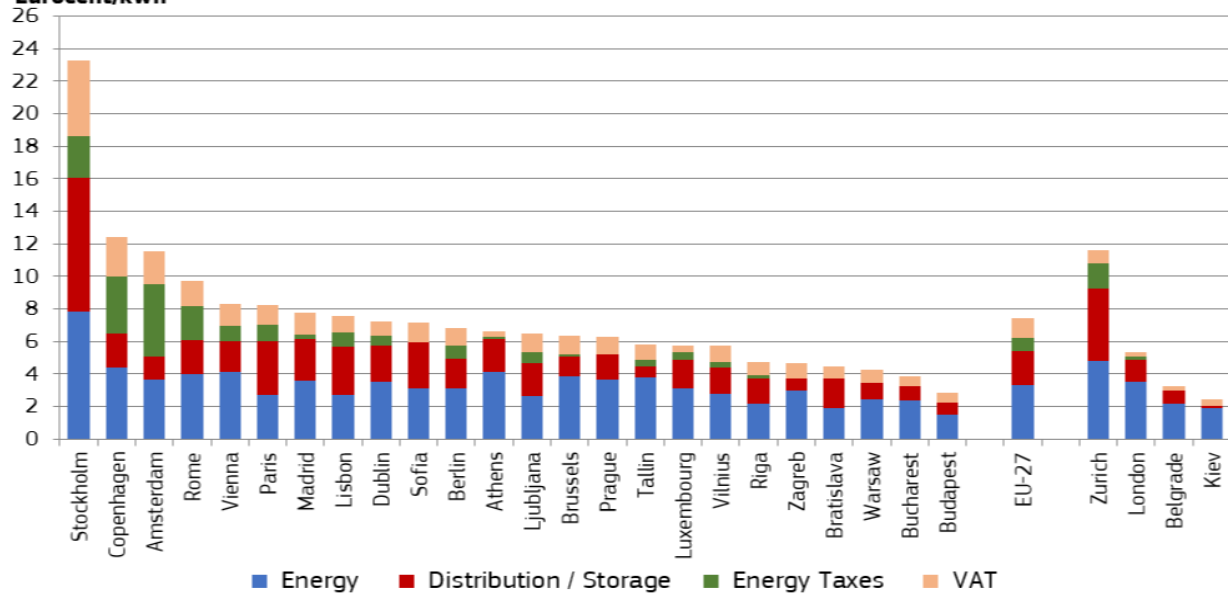


Source: VaasaETT data collection. Saving potential is reported to be zero for Spain and Hungary, for Bulgaria, Croatia, Finland, Latvia, Lithuania, Sweden, Cyprus and Malta no data are available

3.2 Recent developments on EU retail gas markets

- Monthly and quarterly retail prices are estimated by using half-yearly prices from Eurostat (with the latest available figures relating to the second half of 2020) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers.
- For household consumers, the estimated average retail price in Q2 2021 in the EU (including all taxes) was up by 7.5% in year-on-year comparison. In the most typical consumption Band, D2, in the second quarter of 2021 the estimated average price (including all taxes) was 6.9 Eurocents/kWh, similarly to the average of Q1 2021, and up from 6.4 Eurocents/kWh in Q2 2020. (See the estimated household prices on Map 2).
- In the second quarter of 2021, significant differences could be observed in retail gas prices across the EU. The lowest estimated household prices in consumption Band D2 could be observed in Latvia (2.9 Eurocent/kWh), Lithuania (3.0 Eurocent/kWh), Hungary (3.1 Eurocent/kWh) and Romania (3.2 Eurocent/kWh), whereas the highest prices could be measured in Sweden (10.9 Eurocent/kWh), Netherlands (10.1 Eurocent/kWh), Italy (9.0 Eurocent/kWh) and Spain (8.9 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State decreased slightly, to 3.8 (in the previous quarter it was 3.9). Since the first quarter of 2017, when this ratio was 4.0, price differentials decreased, and in Q1 2020 the ratio fell to 3.0, however, since then it rose slightly.
- Figure 39 shows the level and the breakdown of residential end-user gas prices paid by typical households in European capitals in August 2021. On average, 45% of the price covered the energy component, while the rest covered distribution/storage costs (28%), energy taxes (11%) and VAT (17%).
- There were significant differences in August 2021 in the share of energy costs, distribution costs and taxes within the total prices across Member States. The share of energy costs ranged from 31% (Amsterdam) and 33% (Paris) to Tallinn (65%) and Zagreb (64%). The share of distribution/storage costs ranged from 11% (Tallinn) and Amsterdam (13%) to 41% (Bratislava) and 40% (Paris and Sofia). The share of energy taxes ranged from 2% (Athens) and 3% (Madrid and Brussels) to 42% (Amsterdam) and 38% (Amsterdam). For 7 of the 24 capitals covered, the price does not include any energy tax component. VAT content in the total gas price also varied a lot across the EU – from 6% in Athens and 7% in Luxembourg to 21% in Budapest.
- Figure 39 also shows that even the energy component is very variable in absolute terms: in August 2021, it was 5.3 times higher in Stockholm than in Budapest. There were also considerable differences across Member States in the relative share of network costs and taxes. The ratio of highest and lowest network components across the EU was 12.3 (between Tallinn and Stockholm) highest-lowest tax component ratio (taking energy taxes and VAT together) was 14.0 (Athens and Stockholm) in the same period.
- With the exception of three capital cities out of the observed 24, prices were higher in August 2021, compared to the same month of the previous year. Prices decreased in Bratislava (8%), Budapest (4%) and Lisbon (2%), mainly driven by the decrease in energy costs and to a lesser extent, network costs. Prices went up by the most in Athens (82%), Brussels (62%) and Sofia (49%), also principally impacted by energy costs. It seems that recent price increases on wholesale gas markets (at least partly) are already measurable in the final retail household prices in many of the EU capital cities. In August 2021, Budapest remained the cheapest capital in the EU in terms of gas prices for household consumers, followed by Bucharest and Warsaw, whereas Stockholm, Copenhagen and Amsterdam and were the three most expensive capital cities.

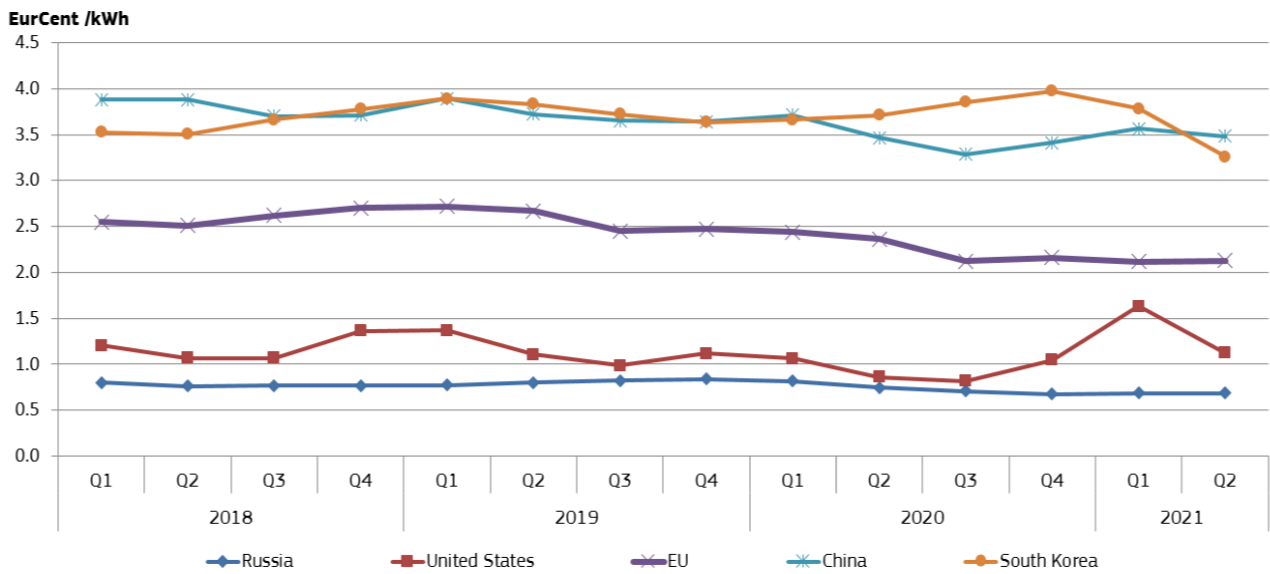
Figure 39 - Breakdown of gas price paid by typical household customers in European capitals, August 2021
Eurocent/kWh



Source: VaasaETT

- Retail gas prices for industrial customers decreased by 9.9% in Q2 2021 year-on-year in the EU on average, and the average estimated price (VAT and other recoverable taxes excluded) in consumption Band I4 was 2.13 Eurocent/kWh, practically remaining unchanged compared to Q1 2021 but down from 2.36 in Q2 2020. (See the estimated industrial prices on Map 3.) There were seven countries in the EU where industrial gas prices increased in year-on-year comparison in Q2 2021, while in the other 17 observed countries (data were not available for Cyprus, Finland and Malta) decreases could be observed. It seems that price recovery on wholesale gas market, started in the second half of 2020 only partially appeared in retail prices for industrial customers in Q2 2021, having average consumption. Decreases could also be observed for industrial customers having larger annual gas consumption (6% decrease in both Band I5 and 9% decrease in Band I6 in Q1 2021 year-on-year).
- It must be noted that these computed quarterly prices are based on Eurostat data (referring to the second half of 2020), corrected by HICP figures, implying that by the time the next half yearly price data will have been available, numbers might show different trends.
- In the second quarter of 2021, the lowest estimated industrial price in consumption Band I4 could be observed in Bulgaria (1.4 Eurocent/kWh), Belgium (1.6 Eurocent/kWh) and Luxembourg (1.7 Eurocent/kWh). The highest prices could be observed in Sweden (3.3 Eurocent/kWh), Slovakia (2.6 Eurocent/kWh) and Austria (2.4 Eurocent/kWh). In Q2 2021, the price ratio of the cheapest and the most expensive country in the EU was 2.3. This price differential was lower compared to the first quarter of 2017, when it was 2.8, but slightly higher compared to the fourth quarter of 2019, when it was only 1.7.
- Figure 40 shows the evolution of industrial retail gas prices in the EU, compared with some important trade partners of the European economy. In the second quarter of 2021, retail gas prices for industrial customers in Korea and China had a price premium to the EU average (respectively 53% and 64%). On the other hand, retail gas prices in the United States were 47% less than in the EU and gas prices in Russia had a discount of almost 68% to the EU average. Compared to Q2 2020, the biggest increase in industrial gas retail prices could be observed in United States (30%). Prices remained practically unchanged in China, whereas they fell in Korea (12%) and Russia (8%). In the EU retail industrial prices were down by almost 10%.

Figure 40 - The EU average industrial retail gas price in comparison with the prices of some important trade partners of the EU



Source: Eurostat (EU average, for industrial consumption band I4) and CEIC. Data of the United States, China, Russia and Korea were taken into account. EU prices are without VAT and other recoverable taxes

- Maps 2 and 3 on the next two pages show the estimated retail gas prices paid by households and industrial customers in the second quarter of 2021.

Map 2 - Retail gas price estimates for households in the EU – Second quarter of 2021



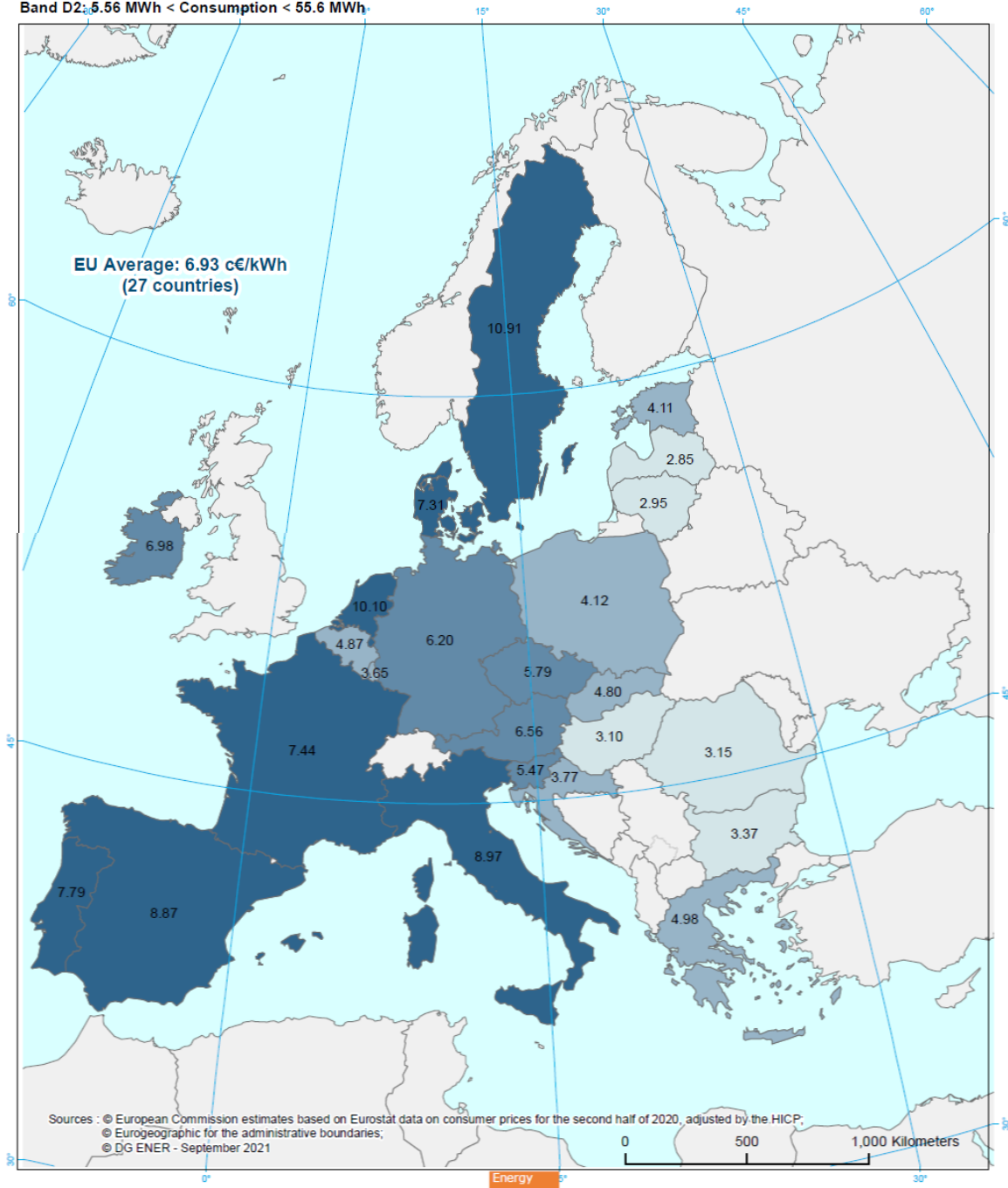
Prices in Eurocents/kWh

- no data
- ≤ 3.50
- 3.51 - 5.00
- 5.01 - 7.00
- > 7.01

GAS PRICES FOR DOMESTIC CONSUMERS
Estimates for the second quarter of 2021

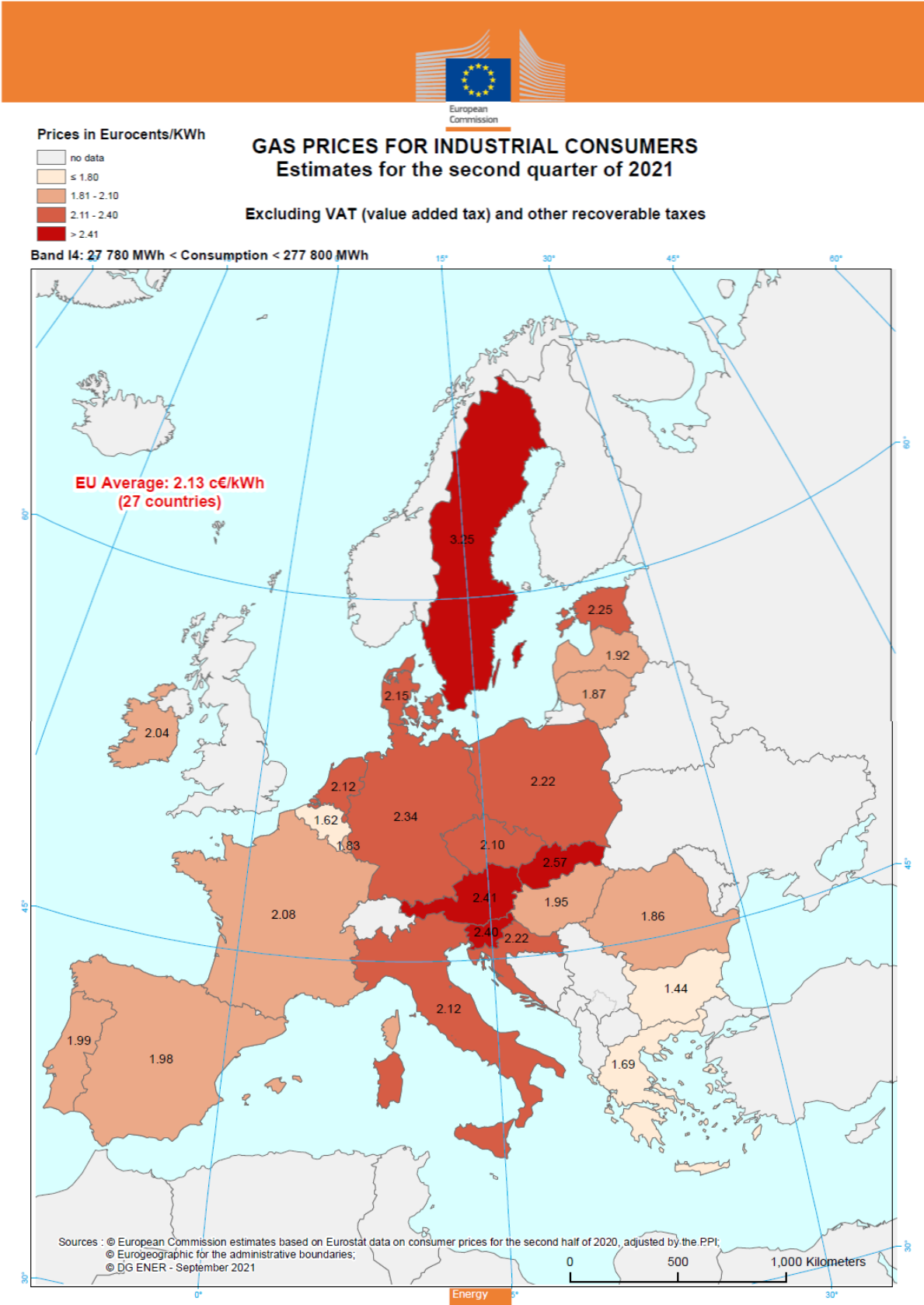
Including all taxes and levies

Band D2: 5.56 MWh < Consumption < 55.6 MWh



Source: Eurostat

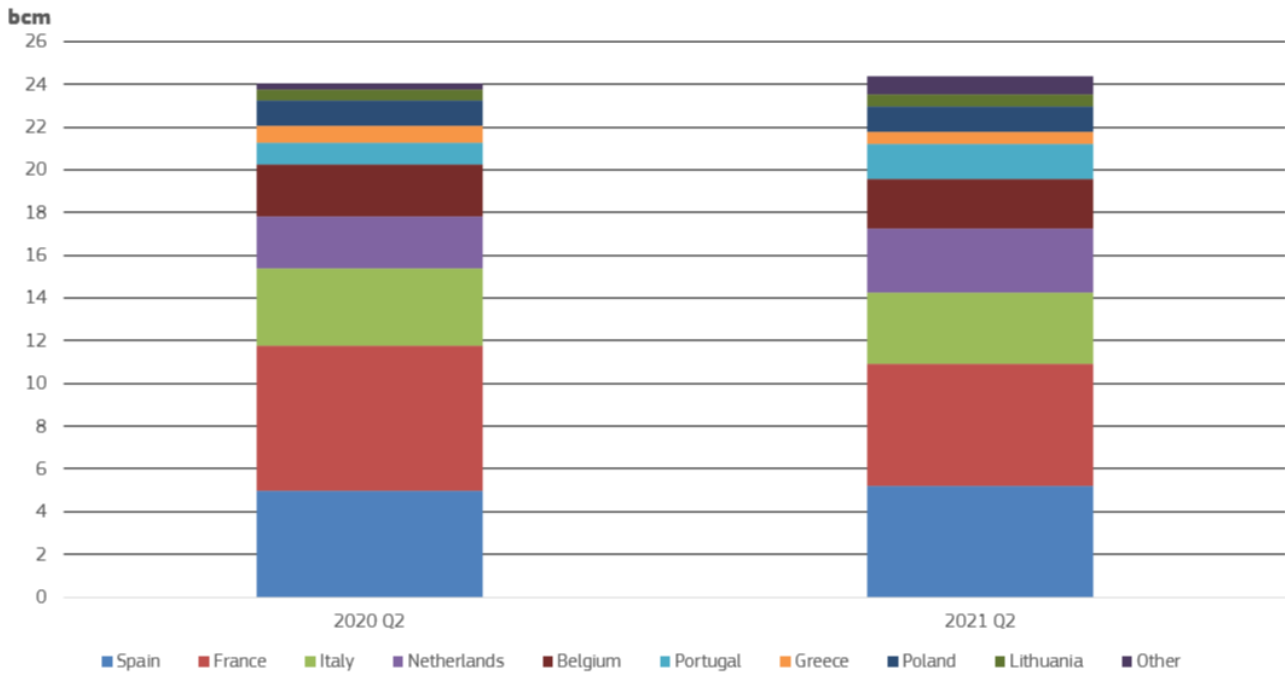
Map 3 - Retail gas price estimates for industrial consumers in the EU – Second quarter of 2021



Source: Eurostat

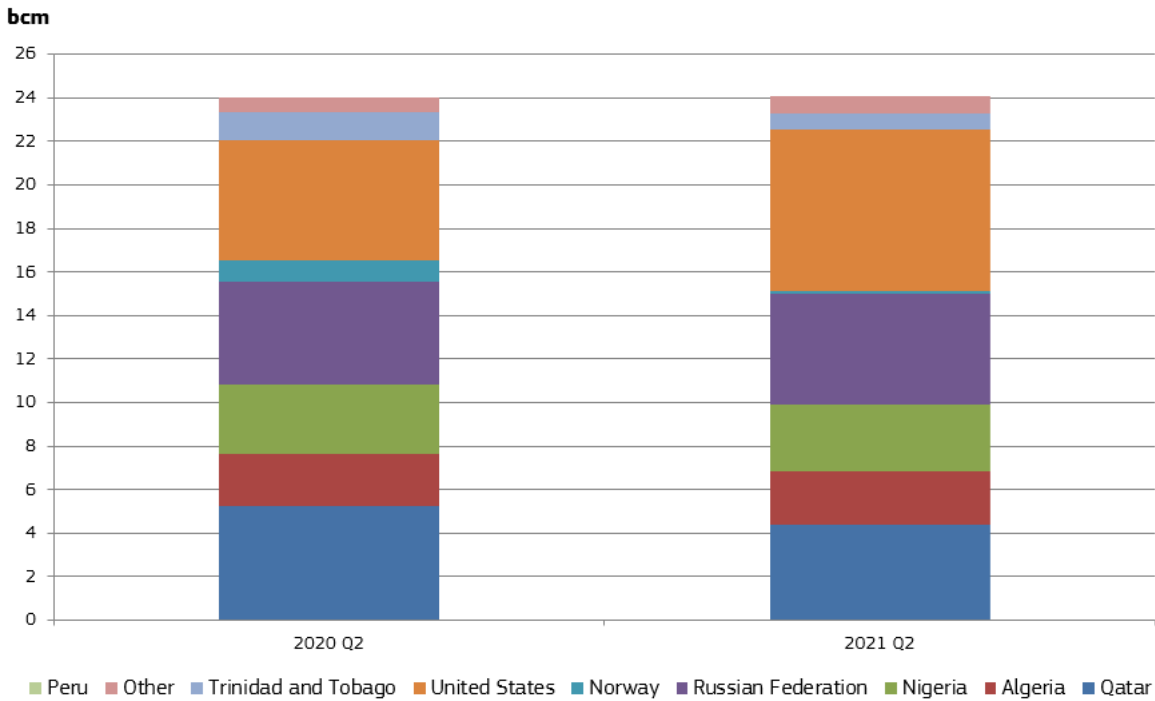
4. Appendix – charts providing further details on market developments³⁰

Figure 41 – LNG imports in the EU Member States, second quarters of 2020 and 2021



Source: Refinitiv

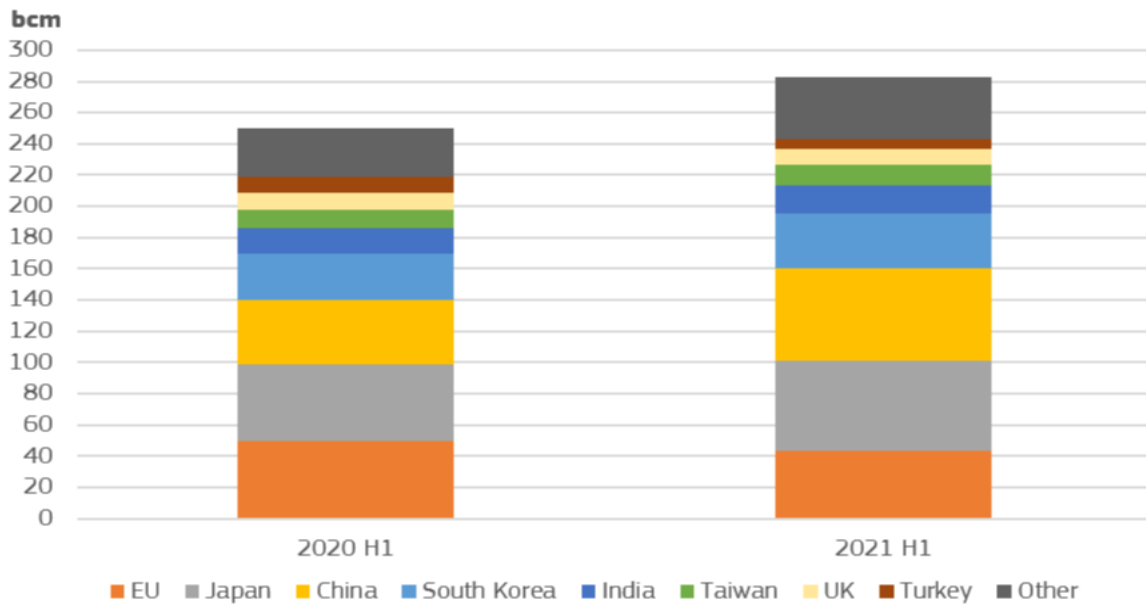
Figure 42 – LNG import from the main suppliers to the EU in the second quarters of 2020 and 2021



Source: Refinitiv

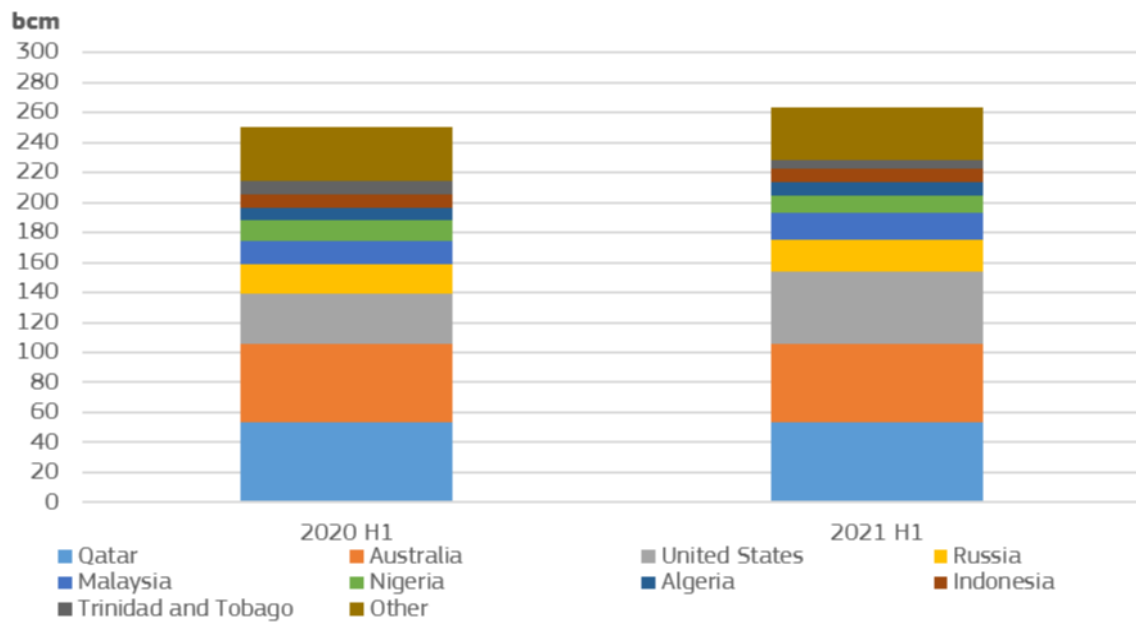
³⁰ These charts provide additional information on the main market developments, without textual comments or further detailed analysis

Figure 43 - LNG imports in the main consumer markets in the first halves of 2020 and 2021



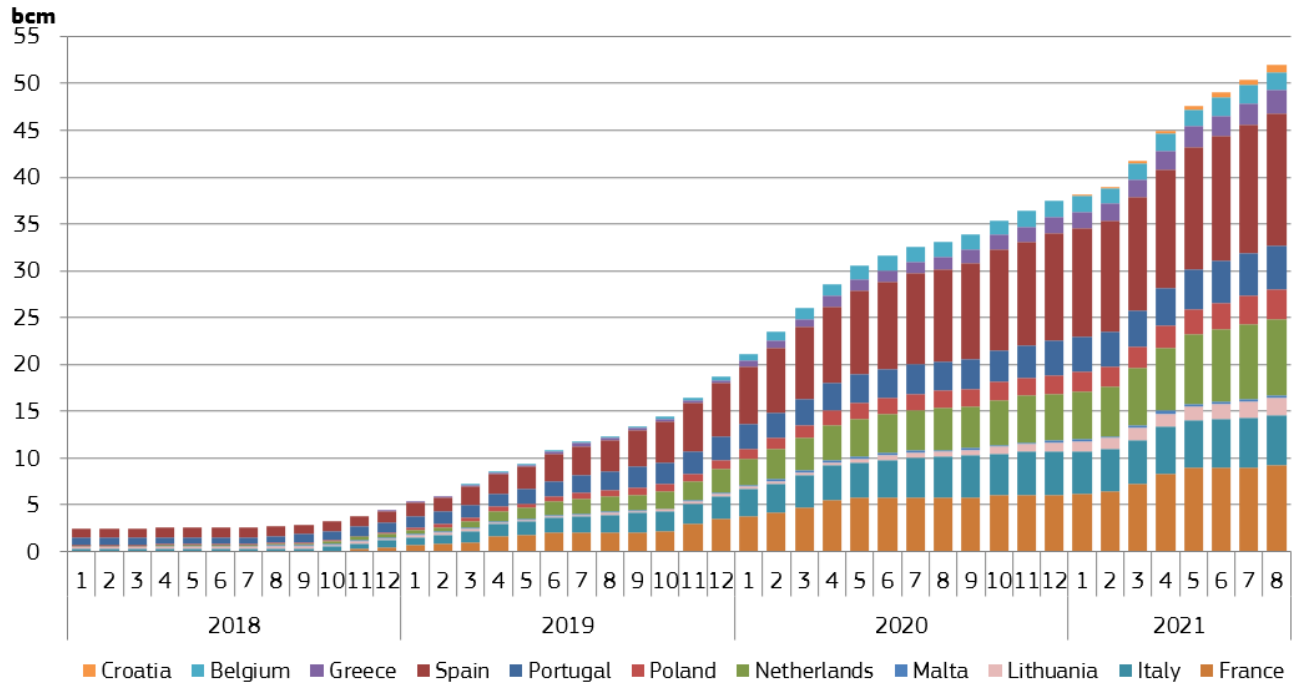
Source: Refinitiv

Figure 44 - LNG exports in the main consumer markets in the first halves of 2020 and 2021



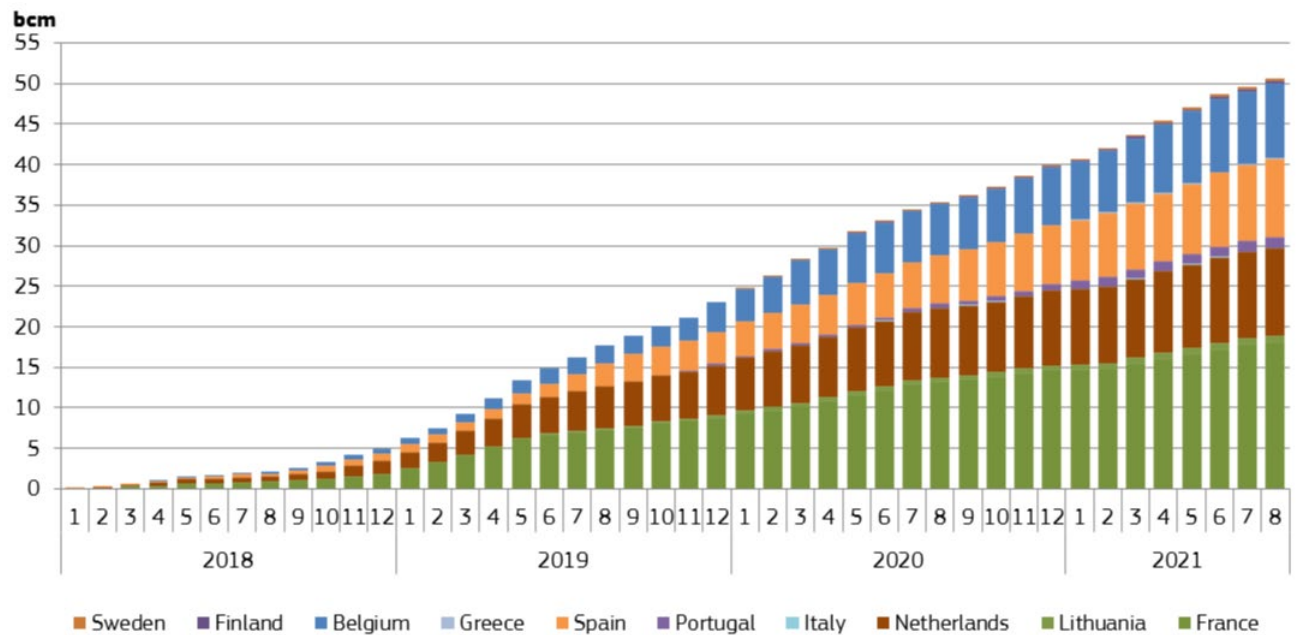
Source: Refinitiv

Figure 45 - Cumulative monthly LNG imports from the US in the EU



Source: Commission calculations based on tanker movements reported by Refinitiv

Figure 46 - Cumulative monthly LNG imports from Russia in the EU



Source: Commission calculations based on tanker movements reported by Refinitiv

5. Glossary

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

Clean dark spreads are defined as the average difference between the price of coal and carbon emission, and the equivalent price of electricity. Dark spreads are reported as indicative prices giving the average difference between the cost of coal delivered ex-ship and the power price. As such, they do not include operation, maintenance or transport costs. Spreads are defined for a coal-fired plant with 35 % efficiency. Dark spreads are given for UK and Germany, with the coal and power reference price as reported by S&P Global Platts.

Clean spark spreads are defined as the average difference between the cost of gas and emissions, and the equivalent price of electricity. Spark spreads are indicative prices showing the average difference between the cost of gas delivered on the gas transmission system and the power price. As such, they do not include operation, maintenance or transport costs. The spark spreads are calculated for gas-fired plants with standard efficiencies of 50% and 60%. This report uses the 50% efficiency. Spreads are quoted for the UK, German and Benelux markets.

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

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

Flow against price differentials (FAPDs): By combining daily price and flow data, Flow Against Price Differentials (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 natural gas systems. With the closure of the day-ahead markets (D-1), the price for delivering gas in a given hub on day D is known by market participants. Based on price information for adjacent areas, market participants can establish price differentials. Later in D-1, market participants also nominate commercial schedules for day D. An event labelled as an FAPD occurs when commercial nominations for cross border capacities are such that gas is set to flow from a higher price area to a lower price area. The FAPD event is defined by the minimum threshold of price difference under which no FAPD is recorded. The minimum threshold for gas is set at 0.5 €/MWh. After the day ahead market closes, market participants still have the opportunity to level off their positions on the balancing market. That is why a high level of FAPD does not necessarily equate to irrational behaviour. In addition, it should be noted that close-to real time transactions represent only a fractional amount of the total trade on gas contracts.

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.

LNG sendout expresses the amount of gas flowing out of LNG terminals into pipelines.

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

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

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

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

