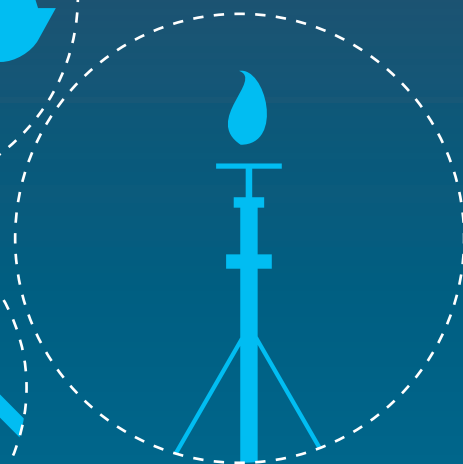
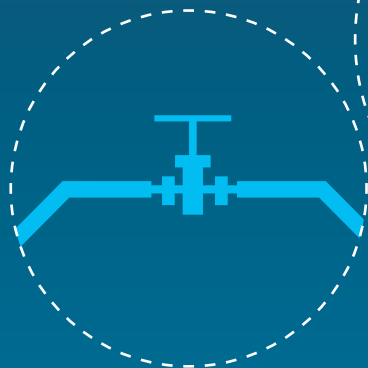
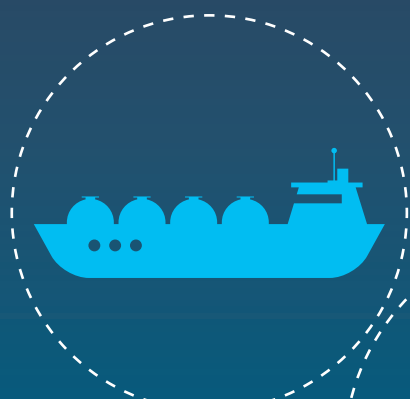




Quarterly report

On European gas markets

With focus on the response from the European
Union and its Member States on high gas prices



Market Observatory for Energy
DG Energy

Volume 14
(issue 3, covering third quarter of 2021)

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HIGHLIGHTS OF THE REPORT

- **Wholesale gas prices in Europe continued their sharp increase in the third quarter of the 2021, as spot contracts rose from 37 €/MWh to 85 €/MWh, which highs were hardly ever seen before on the European hubs. Beyond Q3 2021, spot contracts rose to record highs, well above 100 €/MWh, several times in the final months of 2021, and the wholesale gas market prices became very volatile. Forward contracts also rose significantly, signalling that the market does not anticipate a quick return to the price levels seen in the previous years. High wholesale gas prices resulted in soaring wholesale electricity prices as well. Meanwhile, carbon prices, also impacting wholesale gas market, continued to increase in Q3 2021 and in the following months as well. Coal prices also rose to the highest in the last two decades during the autumn months, and oil prices were up in Q3 2021, and rose further to seven years' high in October 2021. Over the course of time, high energy prices filtered in the retail market and called for policy measures in several countries in the EU.**
- **Global gas market continued to exert fundamental influence on European wholesale gas prices** and kept on determining the LNG availability for our continent. Demand for LNG was still strong in the Asian markets in Q3 2021, driven by local factors, such as summer heat waves and more use of gas in power generation. Asian wholesale gas benchmarks retained their premium over the European peers, and the price differential was big enough to attract most of LNG cargoes, even with higher shipment cost for Asian destinations from big producers amid elevated freight rates, limiting LNG imports in the EU.
EU LNG imports fell again in Q3 2021, by 9% year-on-year, amounting to 17 bcm, after remaining flat in Q2 2021, and significant falls in the previous few quarters. In Q3 2021, Spain was the biggest LNG importer in the EU (4.9 bcm), followed by France (3.7 bcm), and Italy (2.3 bcm). Qatar became the largest LNG source for the EU, ensuring 4.6 bcm of imports, followed by the United States (4.6 bcm) and Nigeria (2.8 bcm), pushing Russia back to the fourth place (2.5 bcm). In the first three quarters of 2021, EU countries imported 58 bcm of LNG, which was lower than in the first nine months of 2020 (67 bcm), with principal import sources, such as the United States (15.9 bcm), followed by Qatar (12 bcm), Russia (11.3 bcm).
- **Low gas storage levels in the EU have increasingly impacted the wholesale gas market and prices in Q3 2021.** At the end of September 2021, the average storage filling rate was 74.6% in the EU on average, which was the lowest over the last decade at this time of the year, and was around 15 percentage point lower than the average of the preceding five years. Over the third quarter of 2021, lower than expected gas inflows from Russia, also appearing in lack of additional capacity bookings at gas infrastructure cross border points, resulted in less opportunity to fill up storages, which was particularly true for storages controlled by the Russian gas company, Gazprom. As until early November 2021 Russia prioritised filling up their domestic storages, low Russian gas inflows resulted in withdrawals from Gazprom managed storages (instead of injections in this period of the year) contributing to the aforementioned general filling rate gap. Low LNG inflows also contributed to low gas supply, making injections more difficult in storages. Ahead of the winter, the highest EU average filling rate was reached on 21 October (77%), around 14 percentage points lower than usual in the preceding five years.
- **EU net gas imports rose by 5% year-on-year** (by 4.2 bcm) in Q3 2021. Russian pipeline supplies covered 41% of extra-EU net gas imports, followed by Norway (27%, reaching five-year high), and LNG imports, amounting to 17%. Increasing Norwegian imports could partially compensate lower than expected LNG inflows and Russian imports. Pipeline imports from Algeria was up by a half year-on-year, and covered 10% of the total extra-EU gas imports in Q3 2021, as oil-indexed price contracts were increasingly competitive vis-à-vis soaring gas hub prices. The Trans Adriatic Pipeline (TAP) ensured 2.7% of the total extra-EU gas imports, whereas the share of Libya was only 1% in Q3 2021. Net gas imports in the EU amounted to 80.7 bcm in Q3 2021, and in the first three quarters of 2021 it reached 251.1 bcm, up from 242.1 bcm in the same period of 2020.
- **A significant drop (-15%) could be observed in Q3 2021 in Russian gas imports through the Belarus transit route** (practically the Yamal pipeline) year-on-year, impacting amongst others the filling rates of Gazprom controlled storages described above. The share of the Belarus transit route fell to 25% (transiting 8 bcm in Q3 2021) within the total Russian pipeline gas imports, whereas the Ukrainian route came to the second place (27%, 9 bcm). Nord Stream remained the most important supply route of Russian pipeline gas to the EU, having a share of 40% in the Russian pipeline imports (13 bcm of gas transit). The share of the Turk Stream was the highest since it was put in operation, 9%, (3 bcm of gas transit). In October-November 2021 gas flows through the Belarus route fell to the lowest in the last seven years. Still in September, Gazprom signed a new long-term contract with the Hungarian MVM, changing the traditional supply route through Ukraine to the Turk Stream, which have impacted the regional gas flows since 1 October 2021.
- **EU gas consumption in Q3 2021 fell significantly, by 10%** (7.5 bcm) year-on-year, amounting to 64.4 bcm. Gas demand in electricity generation fell by 22% (-32 TWh) year-on-year, and increasing gas prices have led to decreasing demand for gas in energy intensive industries as well. Although EU GDP in Q2 2021 was up by 2.1% compared to the previous quarter, and the weather was warmer than usual in July and August in many EU countries, this could not generate sufficiently additional demand for gas that could go against the decreasing trend. EU gas consumption in first three quarters of 2021 amounted to 291 bcm, up by 6% (16 bcm) compared to the same period of 2020.
- **Indigenous gas production in the EU amounted to 11.7 bcm in Q3 2021, slightly up by 4%** (0.4 bcm) compared to Q3 2020. Year-on-year, this was the first increase since the third quarter of 2017, and might have been related to increasing wholesale gas prices that made reactivation of certain gas fields profitable. In Q3 2021, the biggest producer Netherlands produced 4.8 bcm of gas (+14% year-on-year), whereas Romania produced 2.1 bcm (+3%). In the first nine months of 2021, gas production in the EU amounted to 38.5 bcm, down from 40.7 bcm (-6%) a year before.

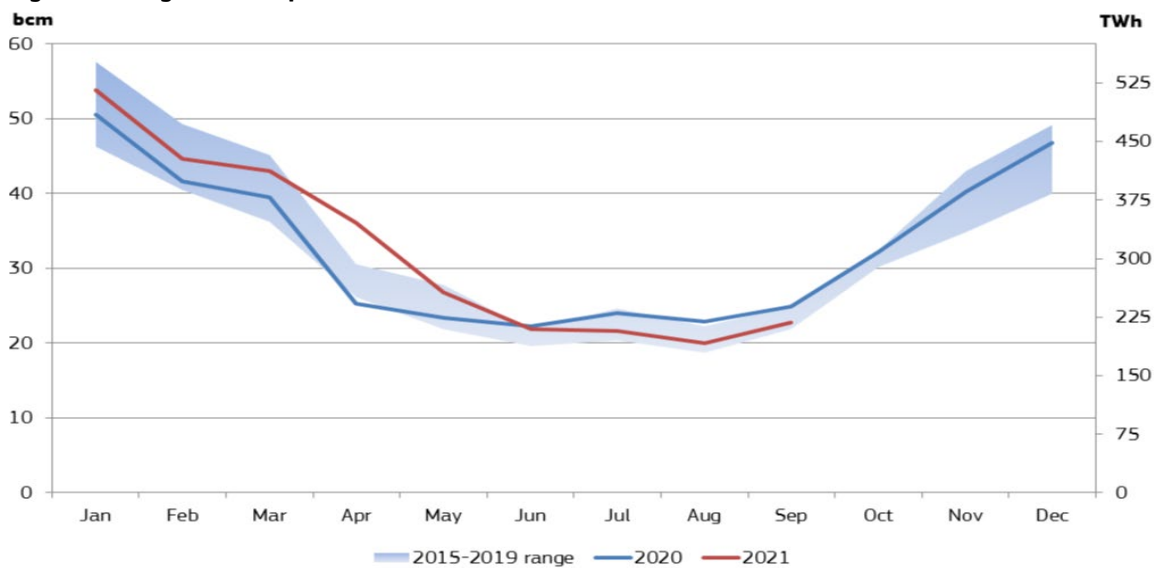
- **Gas traded volumes on the European hubs were up again, by 27% (by 3 590 TWh)** in Q3 2021 year-on-year, after the decrease of 4% in the previous quarter. This was mainly due to increasing trade on exchange markets, while over-the-counter (OTC) trade fell by 8%, in the consequence of smaller traders, having lower financial coverage against default risk, were moving from OTC to exchange markets amid rapidly increasing wholesale gas prices. The share of exchange-executed contracts within the total trade rose above 50% for the first time over the last seven years.
- **Spot prices on the European gas hubs in Q3 2021** were up by around 85-95% compared to the second quarter of 2021, being in a quarterly range of 47-49 €/MWh, whereas they were around six times higher than in Q3 2020. The discount of forward contracts to the spot market widened further over Q3 2021, for year-ahead-to-spot discount rising from 9 €/MWh to 26 €/MWh, implying that the market anticipates a correction in high spot prices in the future. However, as the Dutch TTF hub forward curve suggests, price levels seen in the last few years (15-25 €/MWh) will not return in the near future. Furthermore, the 2022 winter-summer TTF spread was falling in Q3 2021 and became negative in October-November, amid a strong backwardation in the market, which does not provide for strong incentives for refilling gas storages ahead of the next winter in 2022.
- **Retail gas prices for household customers in EU capital cities were up by almost a half in November 2021 year-on-year.** With the exception of one country, gas prices for households in European capital cities were higher in November 2021 compared to the same month of 2020, and in four capital cities prices more than doubled. This implies that recent price increases on wholesale gas markets were already perceivable in retail contracts. In the months to come we can expect further increases in gas retail prices if wholesale market developments are not yet fully priced in. Retail gas prices for industrial customers also increased, up by 24% year-on-year in Q3 2021 for consumers with median annual consumption. The special focus of this report takes a look at the measures the European Union and its Member States can take to mitigate the impact of gas price increases on households and businesses.
- **Hydrogen costs-based assessments** showed that in the Netherlands **production costs of hydrogen** (capital expenditure costs included) with alkaline electrolyser technology amounted to 248 €/MWh in September 2021, whereas with polymer electrolyte fuel cells (PEM) the cost was assessed to 300 €/MWh, and with steam methane forming (SMR) at around 133 €/MWh, showing that recent steep increase in wholesale gas and electricity prices can also be tracked in rising hydrogen price assessments.

1. Gas market fundamentals

1.1 Consumption

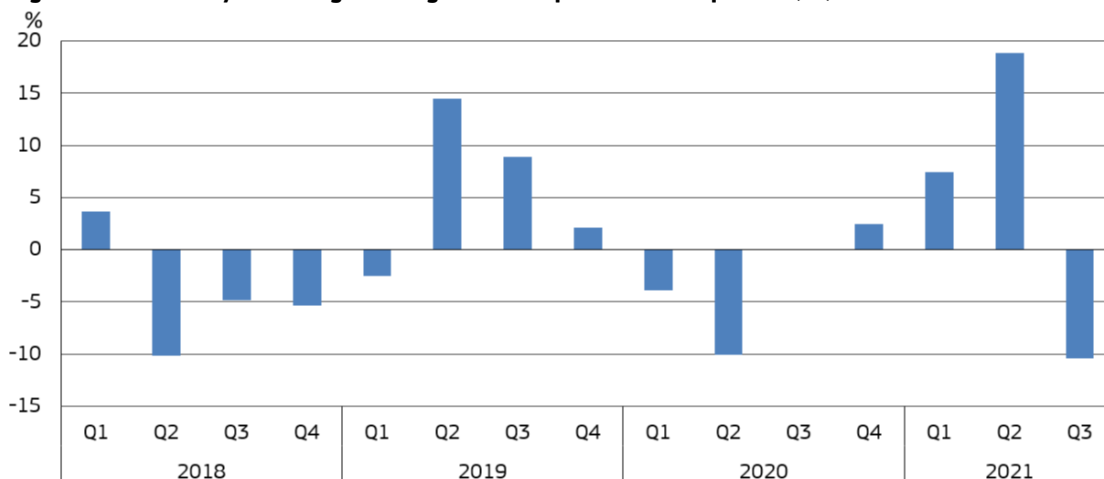
- EU gas consumption¹ in the third quarter of 2021 fell by 10.4% (-7.5 bcm) in year-on-year comparison, after the increase in the first quarter of 2021 (7.4%) and the significant upturn in Q2 2021 (18.9%). In absolute numbers, the quarterly gas consumption in Q3 2021 amounted to an estimated 64.4 bcm, down from 71.9 bcm in Q3 2020, and down from 84.9 bcm in Q2 2021, as the summer season is characterised by seasonally lower consumption. At first glance, this significant year-on-year drop in gas demand in Q3 2021 is surprising, however, gas use in power generation fell by 22% (-32 TWh) year-on-year, which in itself explains a significant part of the gas demand decrease. High wholesale gas prices must also have had an impact on gas demand in energy intensive industries. Although weather was warmer in many countries in Europe in July and August in 2021, this could not generate sufficiently additional demand for gas in power generation that could go against the general decrease in gas demand. As Figure 1 below shows, in the third quarter of 2021 gas consumption in the EU was close to the lower end of the range of the last five years. In first three quarters of 2021, natural gas consumption in the EU amounted to 291 bcm, up by 6% (16 bcm) compared to the same period of 2020.

Figure 1 - EU gas consumption



Source: Eurostat, data as of 9 December 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 (%)

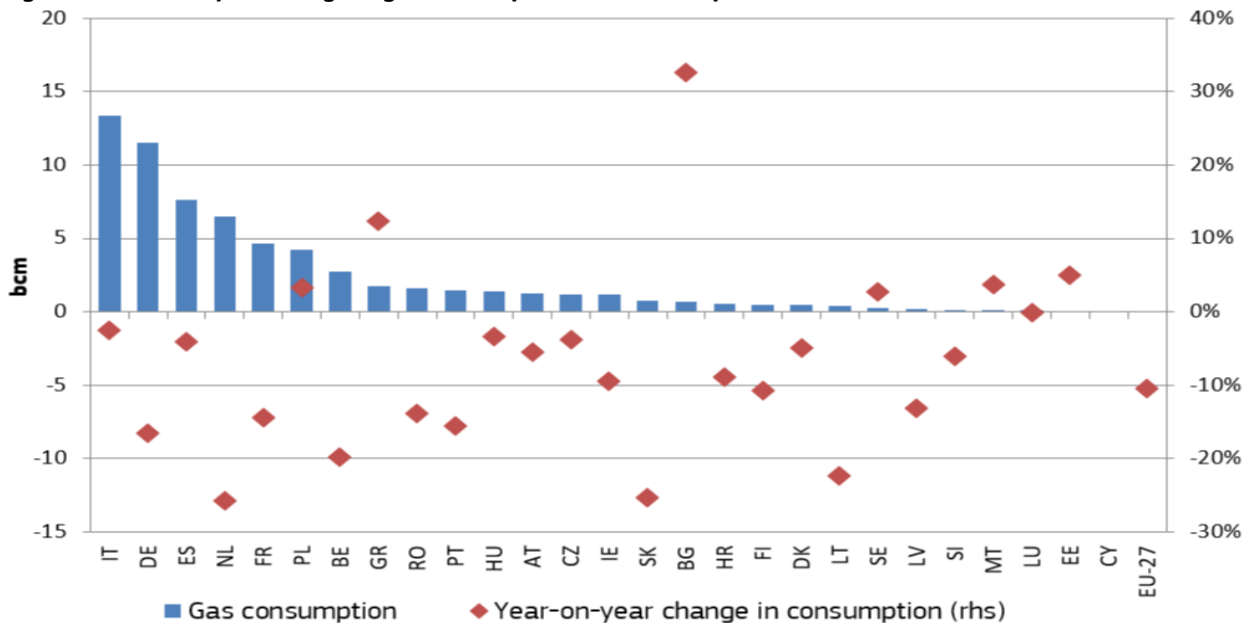


Source: Eurostat, data as of 9 December 2021 from data series nrg_103m. In the next edition of this report numbers might change retrospectively

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 third quarter of 2021, gas consumption increased only in six EU Member States year-on-year (in Bulgaria by 32%, - 0.2 bcm, in Greece, by 12% - 0.2 bcm, in Estonia, by 5% - 0.06 bcm, in Malta, by 4% - 0.1 bcm, in Poland, by 3% - 0.1 bcm, in Sweden, by 3%, with a marginal quantity of 0.01 bcm). In all the other 20 Member States (no data available for Cyprus) gas consumption was down in Q3 2021 year-on-year. Gas consumption, in order of percentage changes, fell by the most in the Netherlands (by 26%, - 2.2 bcm), in Slovakia (by 25%, -0.3 bcm), and in Lithuania (by 22%, -0.1 bcm). On the top of the Netherlands, among the five biggest gas consumer countries, consumption fell by 17% (-2.3 bcm) In Germany, by 14% (-0.8 bcm) in France, by 4% (-0.3 bcm) in Spain and by 3% (-0.4 bcm) in Italy. In Q3 2021 there were seven EU Member States where the year-on-year change in gas consumption was between -10% and -20% and another ten countries, where gas consumption decreased by less than 10%.
- In the first nine months of 2021, gas consumption amounted to 65 bcm in Germany (up by 8%, +5 bcm), in Italy it reached 53 bcm (up by 7%, +3 bcm), in the Netherlands it was 31 bcm (down by 0.3%, -0.1 bcm) in France it reached 28 bcm (up by 8%, +1.9 bcm), and in Spain it amounted to 24 bcm (up by 3%, +0.7 bcm), in comparison to the same period of 2020.

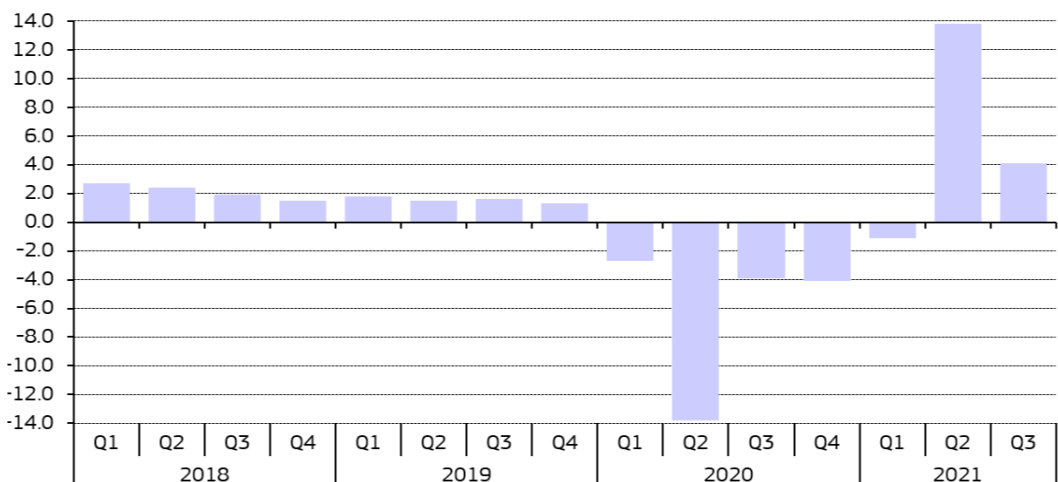
Figure 3 - Year-on-year change in gas consumption in the third quarter of 2021



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

- In the third quarter of 2021, GDP in the EU-27 was up by 4.1% in year-on-year comparison. Although the EU economy still could not get back to its pre-pandemic level, in Q3 2021 GDP was up by 2.1% quarter-on-quarter, however, increase in the general economic activity did not result in increasing gas consumption in the EU, as rapidly increasing wholesale gas prices prompted a decreasing use of gas in electricity generation and energy intensive sectors.

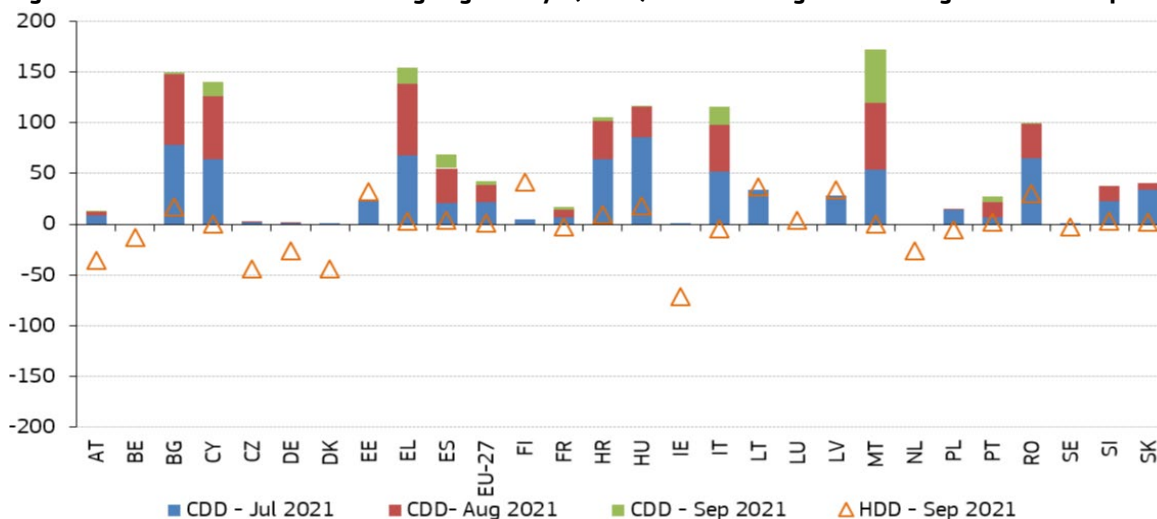
Figure 4 - Change in EU27 GDP, in year-on-year comparison (%)



Source: Eurostat, data as of 7 December 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 third quarter of 2021. In most of the EU countries, especially in south and south-eastern Europe, July and August 2021 was warmer than usual, implying an increasing need for electricity generation, which might impact demand for gas as well, a source frequently relied on during peak electricity demand. However, in Q3 2021 gas demand in electricity generation fell significantly, so temperatures could not have high influence on gas demand. On the other hand, September 2021 was milder in most of Europe than normal (with lower heating degree days), however, this might only have a minor impact on gas demand, and could not influence the generally increasing price trend either.

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



Source: Joint Research Centre (JRC), European Commission

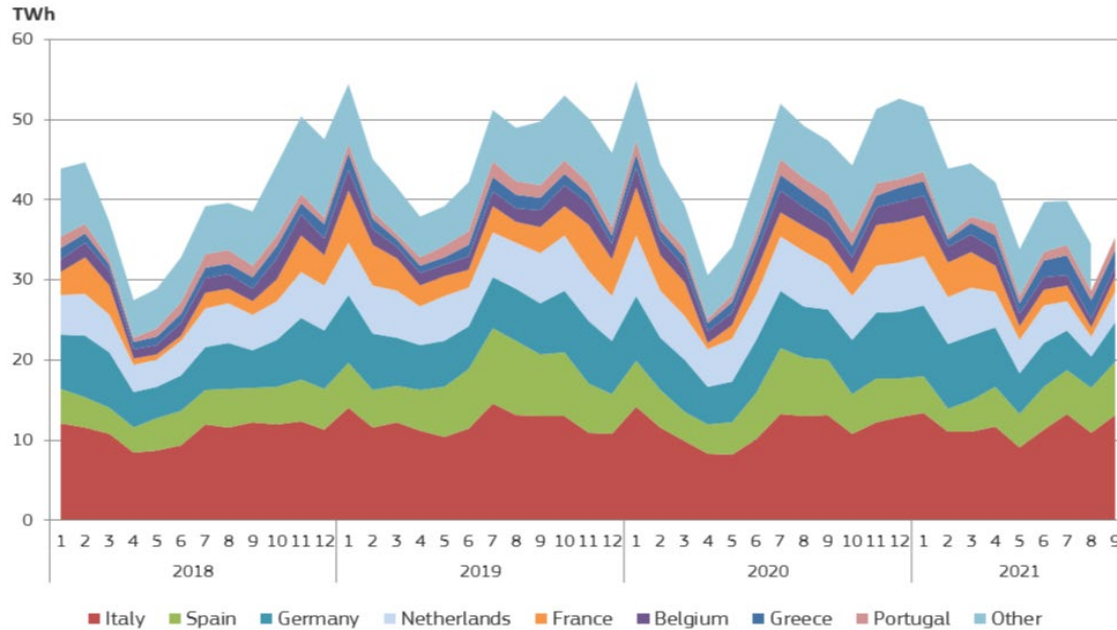
- Based on data from ENTSO-E, gas-fired power generation showed a significant fall in the third quarter of 2021 in the EU, down by 22% (-32 TWh) year-on-year, as Figure 6 shows. In Q3 2021 gas wholesale prices showed a significant increase, rising by the end of September 2021 to levels hardly ever seen on EU gas hubs, which was not favourable to generation costs and profitability of gas-fired generation. In fact, even with increasing carbon prices, high gas prices prompted the comeback of coal to power mixes in many EU countries.
- In year-on-year comparison, the share of renewables in the EU power generation mix remained constant in Q3 2021. Wind, solar, biomass and hydro together represented around 37% of the EU power mix both in the third quarters of 2020 and 2021. In contrast, the share of gas fell measurably year-on-year, and amounted to 18% in Q3 2021, down from 24% a year before. At the same time the share of power generation from solid fuels was up from 12.8% to 15.1%³, as coal and lignite-fired generation together rose significantly, by 22% in Q3 2021 year-on-year. Electricity generation from nuclear rose by 19.6% in Q3 2021 year-on-year, and its share rose from 23% to 26.6%, between the third quarters of 2020 and 2021. Carbon prices also increased over the course of Q3 2021, up from 58 €/MtCO₂e, to 62 €/MtCO₂e however, this had smaller impact on the power mix, as gas prices showed a sharp increase over the same period (from 37 €/MWh to 85 €/MWh). The profitability of gas-fired generation, even amid increasing carbon prices, comparatively decreased vis-à-vis coal and lignite, and hence solid fuel generation was up by 22% whereas gas-fired generation fell by 22% in Q3 2021, year-on-year.
- In Q3 2021, the amount of electricity generated from gas practically halved in the Netherlands, falling by 49% in year-on-year comparison. In France, gas fired electricity generation also fell abruptly, by 46%. In Germany, Spain and Italy electricity generated from gas respectively fell by 30%, 21% and 6% in Q3 2021 year-on-year, whereas in Greece it rose by 24%.
- Besides demand side factors, the share of gas was impacted by changes in the local power generation mixes in each country. In the Netherlands, the decrease in gas-fired generation was mainly compensated by increasing renewables (solar, wind, biomass and hydro) and coal-fired generation. In France, the total amount of generated power was up by 17%, as dwindling gas-fired generation was overcompensated by soaring nuclear and increasing hydro, whereas coal and renewable generation changed only slightly in Q3 2021 year-on-year. In Germany, falling gas-fired generation was practically compensated by increasing coal and lignite, whereas nuclear generation was also up, accompanied by decreasing renewables. In Spain, decreasing gas-fired generation resulted in overall decrease in electricity production, as wind generation was down amid rising solar, with other sources not showing significant changes. Similarly, in Italy decreasing gas-fired generation prompted a fall in overall electricity generation, as albeit increase in coal, hydro generation also went down amid stagnating renewables (biomass, wind and solar). In Greece, as

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 3

exception, gas fired generation was up by 24% in Q3 2021 year-on-year, as increasing demand for electricity required practically all generation sources to contribute to the electricity mix.

Figure 6 - Gas-fired power generation in the EU



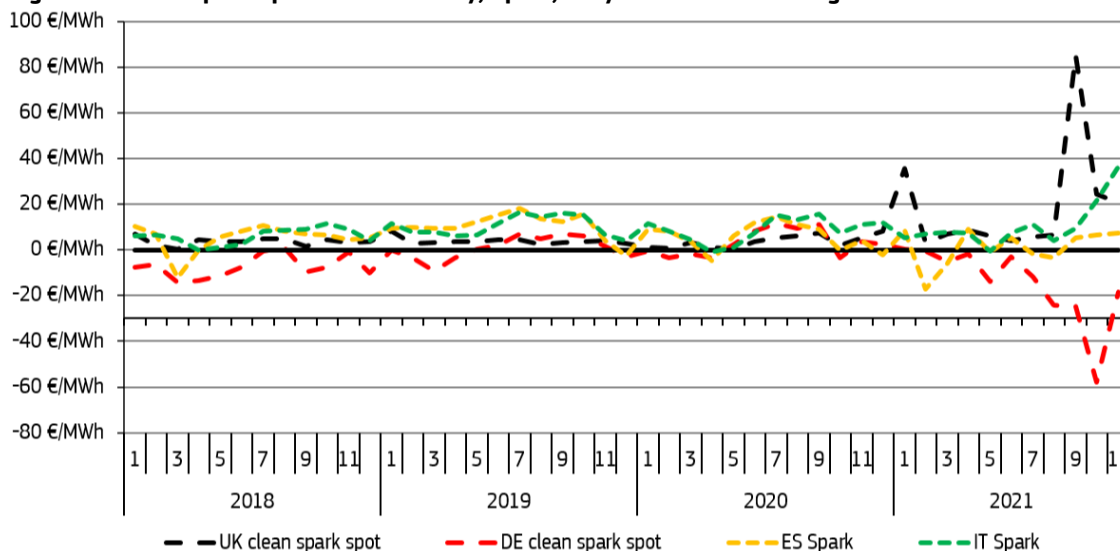
Source: Based on data from the ENTSO-E Transparency Platform and national data sources, data as of 9 December 2021

- Clean spark spreads – measuring the profitability of gas-fired generation by taking into account variable costs – reached respectively -20.2 €/MWh, 0 €/MWh and 8.1 €/MWh in Germany, Spain and Italy in Q3 2021 on average, showing a mixed picture in comparison to the previous quarter, as in Germany and Spain spreads decreased (from -6.2 €/MWh and 4.4 €/MWh in Q2 2021, respectively), whereas in Italy they rose from 4.6 €/MWh measured in Q2 2021. The decrease in the clean spark spreads implied decreasing profitability of gas-fired generation⁴ in Germany and Spain and improving profitability in Italy (See Figure 7⁵). However, constantly increasing electricity prices, especially in September, and beyond Q3 2021, in October in November, largely driven by gas prices, turned the spreads into positive range again in Spain and Italy, and in Germany the negative clean spark spread also improved after the trough in October.
- In the United Kingdom, having relevance for the European gas market, clean spark spreads averaged at 32.8 €/MWh in Q3 2021, rising from 6.2€/MWh in Q2 2021, which latter equaled the spread of Q3 2020 as well. In the UK wholesale electricity prices were much higher than in continental Europe, resulting in higher profitability of gas fired generation. However, electricity generated from gas was down by 4% year-on-year in Q3 2021, and the share of gas-fired generation was 49% in the same period, as opposed to 47% in Q3 2020, which was the consequence of generally falling power generation in the country, probably with greater exposure to imports.

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



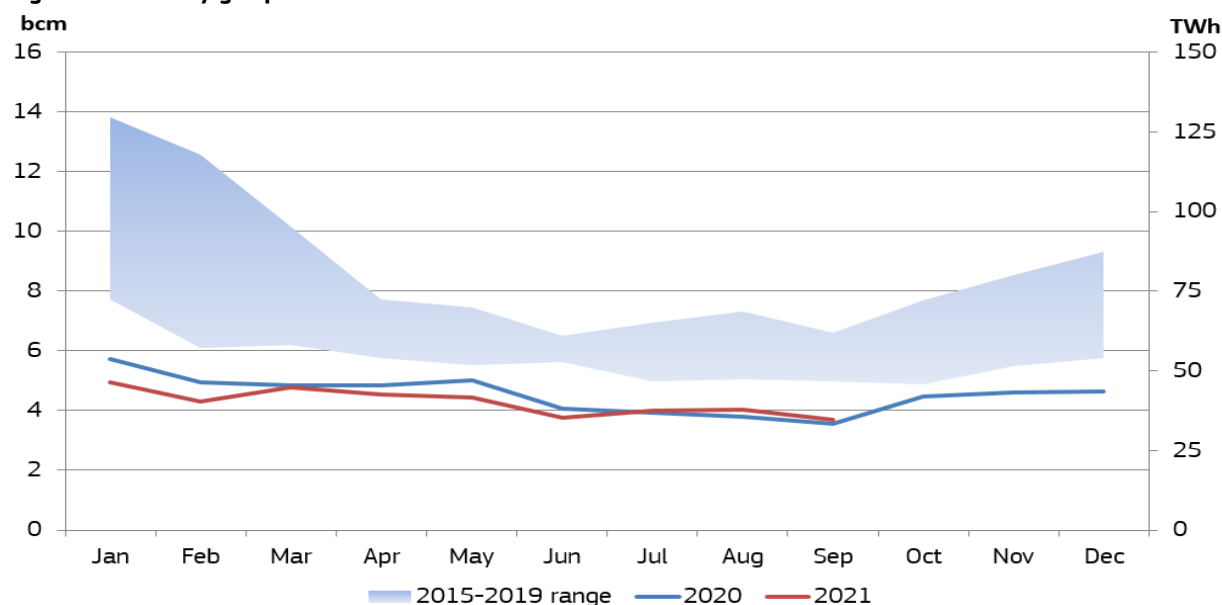
Source: Bloomberg

1.2 Production

- In the third quarter of 2021, EU gas production reached approximately 11.7 bcm⁶, slightly more (by 4%, 0.4 bcm) than in the same quarter of 2020 (See Figure 8). Although it was the first time since Q3 2017 when EU gas production showed an increase year-on-year, during the whole quarter gas output was below the 2015–2019 range, reflecting the long-term dwindling trend of gas production in the EU. The Q3 2021 total EU production is only 0.4 bcm higher than a year before, when the lowest quarterly production could be observed in the last eight years.
- The increase in the EU gas production in Q3 2021 was mainly driven by the biggest producer Netherlands, where production rose by 14% (by 0.6 bcm), amounting to 4.8 bcm. In Romania, the second biggest gas producer in the EU, production went up only by 3%, in Poland by a negligible 1% and in Germany by 8% (in all of the three countries the production rose by less than 0.1 bcm). Increasing gas production in some EU countries might have been related to increasing market prices, prompting the reactivation of gas production at costlier fields.
- On the other hand, gas production in Italy was down by 12% (-0.1 bcm) year-on year, and in Hungary by 13% (-0.05 bcm). In Q3 2021, the six biggest gas producer countries in the EU were: the Netherlands (with 4.8 bcm of production), Romania (2.1 bcm), Poland (1.4 bcm), Germany (1.2 bcm), Italy (0.8 bcm), and Hungary (0.4 bcm).
- In the first three quarters of 2021, Dutch gas production, amounting to 17 bcm, was down by 4% (-0.7 bcm), whereas in Romania production (2.1 bcm) remained practically stable (+1%), reaching 6.7 bcm. Gas production in Poland was also stable year-on-year, around 4.1 bcm in January–September 2021, whereas Germany produced 3.6 bcm of gas, down by 5% (-0.2 bcm). In Italy gas production amounted to 2.5 bcm (falling by 17%, or -0.5 bcm year-on-year), and both Hungary and Ireland produced 1.1 bcm (respectively down by 12% and 27%, or 0.1 bcm and 0.4 bcm) in the first nine months of 2021. In the same period, gas production in the EU amounted to 38.5 bcm, down from 40.7 bcm (-6%) a year before.
- Gas production in Norway increased by 5% year-on year, from 28.6 bcm in Q3 2020 to 30 bcm in Q3 2021. In the first nine months of 2021, natural gas production in Norway amounted to 88 bcm, slightly up from 87 bcm in the same period of 2020. In the United Kingdom, gas production amounted to 9.1 bcm in Q3 2021, up from 8.9 bcm a year before, while in the first three quarters of 2021 gas production fell to 23.3 bcm, from 29.9 bcm, measured in the same period of 2020.

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 December 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 5% (4.2 bcm) in the third quarter of 2021 (year-on-year), amid decreasing gas consumption and higher domestic production, presumably only temporarily going up. Net imports in different EU countries showed a high variation in Q3 2021. In Austria net imports rose by 165% (+2 bcm) year-on-year, in Romania they went up by 94% (+0.3 bcm) and in Czechia by 35% (+0.6 bcm). On the other hand, in both Portugal and Latvia net gas imports fell by 27% in Q3 2021 year-on-year (respectively decreasing by 0.4 bcm and 0.3 bcm), and in Lithuania it fell by 25% (-0.1 bcm).
- Looking at the biggest importers, in France net gas imports rose by 25% (+1.9 bcm), in Germany by 18% (+2.6 bcm), in Poland by 7% (+0.3 bcm). At the same time, net gas imports were down by 18% (-1.3 bcm) in the Netherlands and by 11% (-0.9 bcm) in Spain. In Italy net imports did not show significant change in Q3 2021 year-on-year. The biggest net importers in the EU were Germany (17 bcm), Italy (16 bcm), France (10 bcm), Spain (8 bcm), the Netherlands (6 bcm) and Poland (4 bcm). These six countries represented together three quarters of the total EU net gas imports in Q3 2021, which amounted to 80.7 bcm, up from 76.5 bcm in Q3 2020.
- In the three quarters of 2021, net gas imports in the EU amounted to 251.1 bcm, up from 242.1 bcm in the same period of 2020 (representing an increase of 4%). Germany imported 60 bcm of gas, followed by Italy (53 bcm), France (30 bcm), Spain (24 bcm), Poland (14 bcm) and Belgium (13 bcm).
- According to ENTSO-G data, net imports amounted to 875 TWh in the third quarter of 2021, of which 83% arrived through pipelines and around 17% through LNG terminals. Pipeline gas imports from Russia rose slower than in the previous quarter, up by 2% in year-on-year comparison. In contrast, imports from Norway were up by 10% in Q3 2021. Pipeline gas imports from Algeria, showed a remarkable increase of 48% year-on-year, though it grew to a lesser extent than in the previous quarter. Pipeline gas imports from Libya fell further, by 22% year-on-year. At the same time, LNG imports reached 147 TWh in Q3 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 41% in the third quarter of 2021, similarly to the same quarter of 2020⁸.
- The share of pipeline gas imports from Norway rose to 27% in the third quarter of 2021, and was the highest since Q1 2016, as the increase in imports from Norway outpaced the overall increase in gas imports in the EU. Even if there were planned maintenances and unplanned outages on Norwegian gas infrastructure in Q3 2021, competitive gas imports from Norway could at least partially compensate dwindling LNG inflows and sluggish gas flows from Russia. In the third quarter of 2021, Norwegian gas production⁹ amounted to 30 bcm, up by 5% year-on-year.

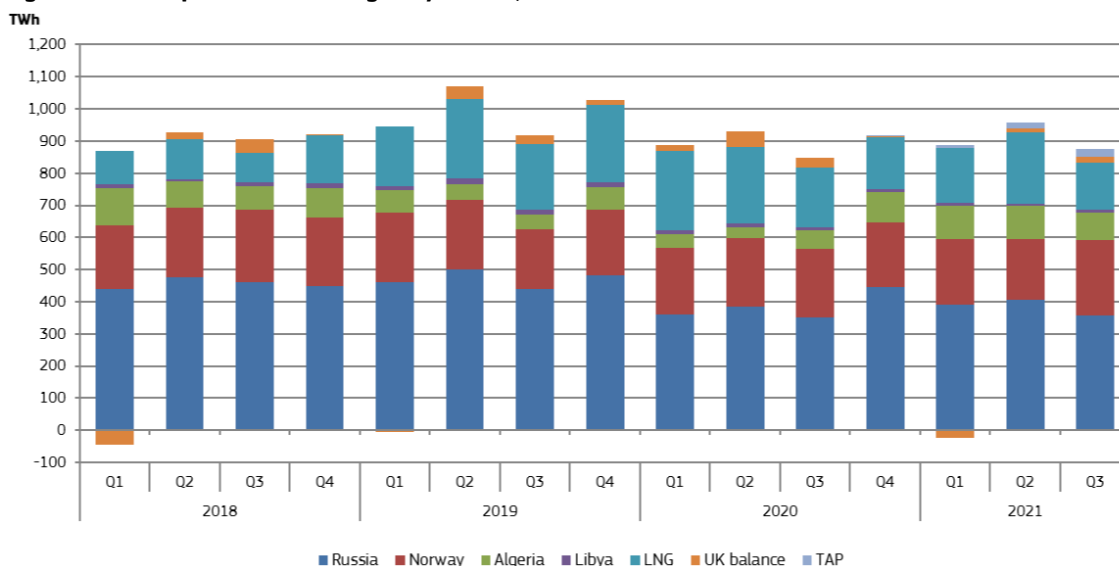
⁷ Net imports equal imports minus exports and do not account for stock changes.

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

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

- In the third quarter of 2021, pipeline gas imports from Algeria were up by 48% year-on-year, which resulted in an increasing share within the total extra-EU imports (10% in Q3 2021 up by 3 percentage points compared to Q3 2020). Increasing pipeline gas imports from Algeria must have been related to the oil-indexed contracts, becoming competitive to hub-based pricing, in the consequence of the recent steep increase in wholesale gas prices on the European hubs, including Spain and Italy, where Algerian imports compete with, amongst others, LNG imports having hub-linked prices. Imports from Libya continued to fall and its share was only 1% in the total EU gas imports, decreasing from 1.3% in Q3 2020.
- In Q3 2021, the share of LNG fell below 17% in the total EU gas imports, which was the lowest since Q4 2018, and also lower (by 5 percentage points) than in Q3 2020. 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. It seems that in Q3 2021 the year-on-year decrease in the share of LNG, and inflows from the UK was mainly compensated by the increasing share of Norwegian and Algerian pipeline gas and the appearance of the TAP pipeline, as new supply route, whereas the share of Russian pipeline sources decreased only slightly.
- The Trans Adriatic Pipeline (TAP), operational since the end of 2020, ensured around 23 TWh gas imports in the EU in the third quarter of 2021, up from 18 TWh in the previous quarter, and representing around 2.7% of the EU total gas 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 nine months of 2021, gas imports in the EU amounted to 2 699 TWh, slightly up, by 1.2%. Russian pipeline gas was the biggest supply source (43%), followed from pipeline gas from Norway (23%), LNG regasification terminals (20%), Algerian pipeline gas (11%) and pipeline gas via the TAP (2%) 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 2 December 2021.

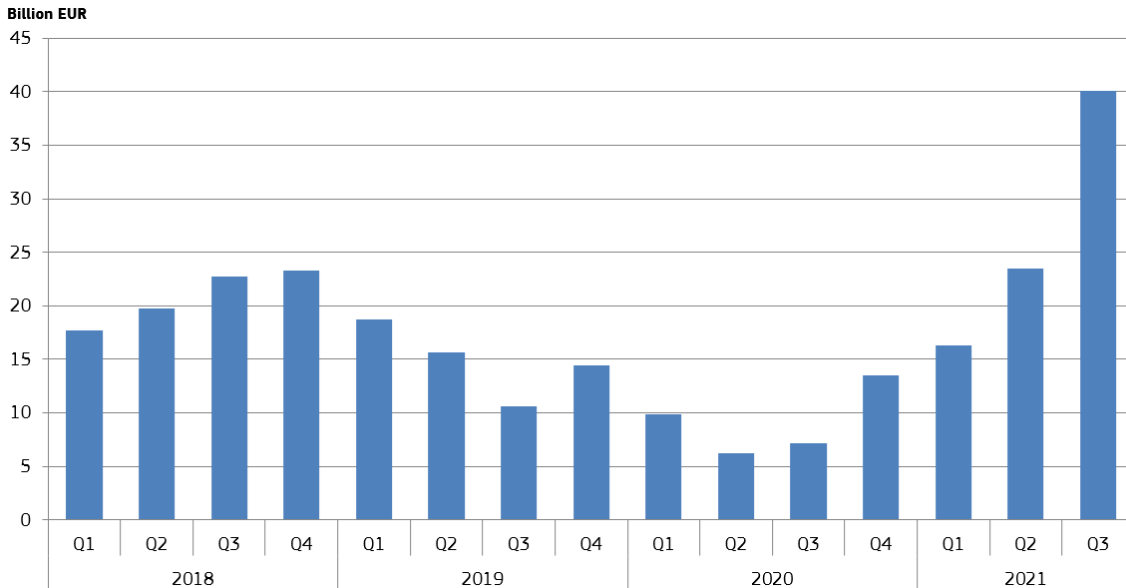
Exports to the Baltic-states and Finland are not included in the chart owing to unavailability of reliable data

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.

- As average import prices significantly increased year-on-year (showing a more five-fold upturn compared to Q3 2020), in the third quarter of 2021 the estimated gas import bill amounted to €40 billion, in comparison to €7.1 billion in Q3 2020, rising by 462% year-on-year. However, it should be noted here that the estimation of the gas import bill is based on spot wholesale prices, rising by an estimated 445% in Q3 2021 year-on-year, which given the significant premium of spot price over forward contracts and oil-indexed prices, may overestimate the actual gas import bill in Q3 2021. Bearing this in mind, the quarterly gas import bill was up in Q3 2021 compared to the previous quarter (€23.5 billion in Q2 2021 vs. €40 billion in Q3 2021). In the three quarters of 2021 the EU gas import bill amounted to €79.8 billion, up from €23.2 billion compared to the same period of 2020.

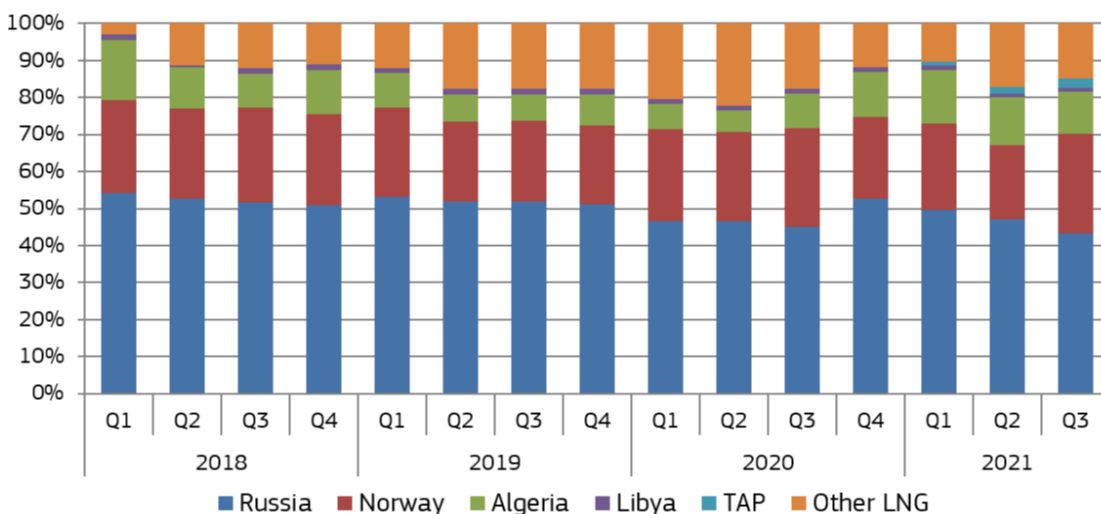
Figure 10 – Estimated quarterly extra-EU gas import bill, in billions of euros



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 imports including all gas sources. As Figure 11 shows, the share of Russia within total extra-EU gas imports (pipeline and LNG together) amounted to 43% in Q3 2021 (the lowest since Q1 2015), split by 41% of pipeline imports and 2% of LNG. Even though the share of LNG imports from Russia decreased in Q3 2021, the country is also an important participant in European LNG market, not only in the traditional pipeline gas supply, trying to maintain its market share by switching to a more competitive export strategy. The share of pipeline import gas of Russian origin went remained at 41% within the total extra-EU gas imports, by taking into account LNG the share of Russia decreased from 45% to 43% in Q3 2021 year-on-year.
- The share of Norway was 27% in Q3 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 11.5% with LNG (as opposed to 9.7% only including pipeline gas) within the total extra-EU gas imports. The share of LNG was 15% in Q3 2021, (on the top of LNG accounted in shipments from Russia, Norway and Algeria), down from 18% in Q3 2020 and from 17% in the previous quarter. The decreasing share of imports from Russia and other LNG between the third quarters of 2020 and 2021 was mainly compensated by the increasing shares of Algeria, and the new TAP pipeline supply route, whose latter share was 2.7% in the total extra-EU gas imports in Q3 2021.

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

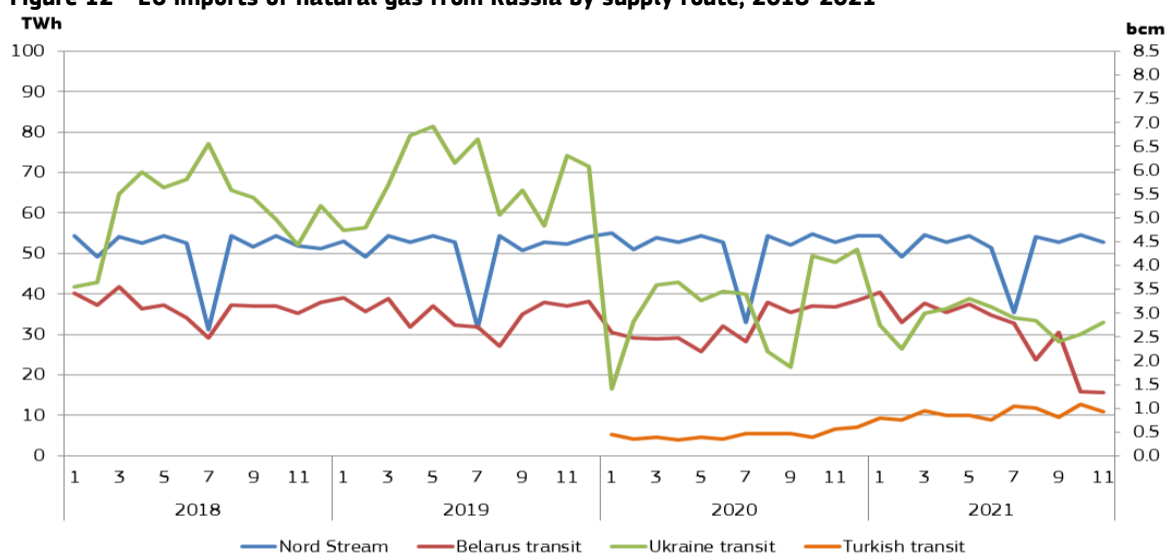


Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 December 2021.

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 (practically the Yamal pipeline), Nord Stream 1 and Turk Stream.
- In the third quarter of 2021, the volume of Russian imports rose by 2%, if compared with the same quarter of 2020. As shown on Figure 12, gas flows transiting via Ukraine were 9% higher than in Q3 2020, in contrast to the year-on-year fall observed in the few previous quarters. During Q3 2021 a monthly average of 3 bcm of gas of Russian origin was transited through Ukraine, down from the monthly average of Q2 2021 (3.5 bcm), but up from the average a year before (2.7 bcm).
- In contrast to Ukraine, flows through Belarus fell by 15% in Q3 2021 year-on-year. During the summer and autumn months less inflows from Russia mainly impacted flows through the Yamal pipeline. In Q3 2021 the average monthly Yamal transited volume was 2.7 bcm (down from 3.2 bcm a year before), and in November-December monthly volumes fell below 1.5 bcm, which was not seen in the last seven years. Transited volumes through the Nord Stream were slightly up by 2% in Q3 2021 (reaching 4.4 bcm on monthly average) compared to the same quarter of 2020. At the same time, transited volumes through the Turk Stream practically doubled (+102%), and the monthly average transited volume was 1 bcm in Q3 2021.
- As a result, in Q3 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, practically the same as a year earlier. The Ukraine transit route resurged to the second place, ensuring 27% of the total Russian pipeline gas transit, up from 25% year earlier. The share of the Belarus transit route fell back to the third place, representing 24% of the total Russian pipeline imports in Q3 2021, down from 29% in Q3 2020. The share of Turk Stream reached the highest since the start of this operation in early 2020, 9% in Q3 2021, up from 5% in Q3 2020 and from 7% in the previous quarter, Q2 2021.
- In Q3 2021 Nord Stream represented 16% (13 bcm) in the total net extra-EU gas imports, the Ukrainian transit had a share of 11% (9 bcm), whereas the Belarus transit route ensured 10% (8 bcm). At the same time, the Turk Stream had a share of 4%, with around 3 bcm gas transit within the total net extra-EU gas imports in Q3 2021. It seems that in Q3 2021 the Europe faced only slightly increasing imports from Russia, which was principally satisfied via the Nord Stream, the Turk Stream and Ukraine, whereas Belarus transits fell measurably.
- In January-September 2021, transited volumes through Nord Stream was almost 43 bcm (practically unchanged year-on-year), Belarus transit reached 29 bcm (up by 10%, year-on-year), the Ukraine transit (only counting the destinations within the EU) was 28 bcm (practically unchanged), while transit on Turk Stream was almost 9 bcm, up by 112%. In Q3 2021 and in October-November as well, Gazprom booked less than expected additional interconnection capacities on infrastructure transiting gas through Ukraine and Belarus. Russia managed to ship less gas to the European customers over this period, as until the beginning of November it was said to be a priority to fill up its domestic storages. Less than expected inflows from Russia made some speculations on exerting pressure on the EU to swiftly authorise the new Nord Stream 2 pipeline, however, it also put into question Russia's long-enjoyed status of last resort supplier of gas to Europe, in case of supply limits owing to domestic reasons.

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

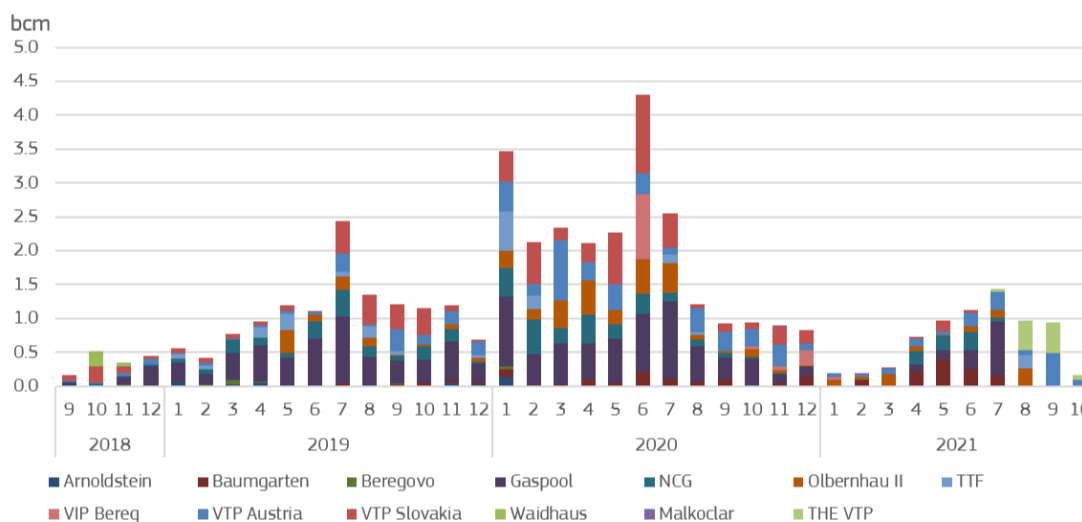


Source: Based on data from the ENTSO-G Transparency Platform, data as of 2 December 2021.

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) picked up slightly in Q3 2021 and reached 3.4 bcm after 2.8 bcm in the previous quarter, Q2 2021. However, traded volumes in Q3 2021 were still down by 28% year-on-year. In July 2021 traded volumes were close to 1.5 bcm, however, in August and September they fell below 1 bcm again. In October 2021, traded volumes on ESP fell to minimal levels again (0.16 bcm).
- In Q3 2021 the principal delivery points from ESP sales were the German VTP (1 bcm), the Austrian VTP (0.8 bcm), the two German hubs, NGC and Gaspool (0.8 bcm), Obernhau II (0.4 bcm), Baumgarten and the TTF (close to 0.2 bcm each).
- As of August 2021 the difference between spot and forward prices might have reached levels when it was no longer profitable to sell day-ahead and short term contracts on the ESP, rather using direct imports or withdrawal from storages. As of the summer, mainly 2022 and 2023 contracts were sold on ESP (as of September mainly the latter). As of 13 October the ESP did not register any contract, practically under the current high price environment buyers do not want to buy further contracts.

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



Source: Gazprom Electronic Sales Platform. For October data were only available for the beginning of the month.

- As it was announced several times during 2021, Gazprom expects its 2021 gas exports to Europe (including Turkey and non-EU member European countries) at 183 bcm, up by 6 bcm compared to 2020.¹⁰ The company said that in January-September its gas exports outside the Former Soviet Union (FSU) jumped more than 15% compared to the same period of 2020, to 145.8 bcm. By the end of November, the company increased its gas exports to these countries to 171.5 billion cubic meters, which is higher than the figure for the same period of 2020 by 6.6 per cent (or by 10.6 billion cubic meters).
- According to data from the Ukrainian gas TSO, natural gas transportation from EU countries to Ukraine showed an increasing trend in Q3 2021: in July, August and September the monthly imports respectively amounted to 498 mcm, 567 mcm and 665 mcm, altogether more than 1.7 bcm¹¹. In the first nine months of 2021, total Ukrainian imports from the EU amounted to 2.4 bcm of gas, while export and re-export amounted to 1.15 bcm. As of October 2021, gas transit through Ukraine to Hungary fell significantly, in the consequence of re-routing gas shipments from Russia via the Turk Stream. This limits the opportunities importing the natural gas from the EU using the cheapest route, through Hungary. According to Gas TSO of Ukraine, in 2021, all of the natural gas imports from Hungary was conducted by virtual reverse. Therefore, without the physical transit of Russian gas, the import via this direction becomes more complicated and depends on the technical capabilities of the Ukrainian and Hungarian Gas TSOs.

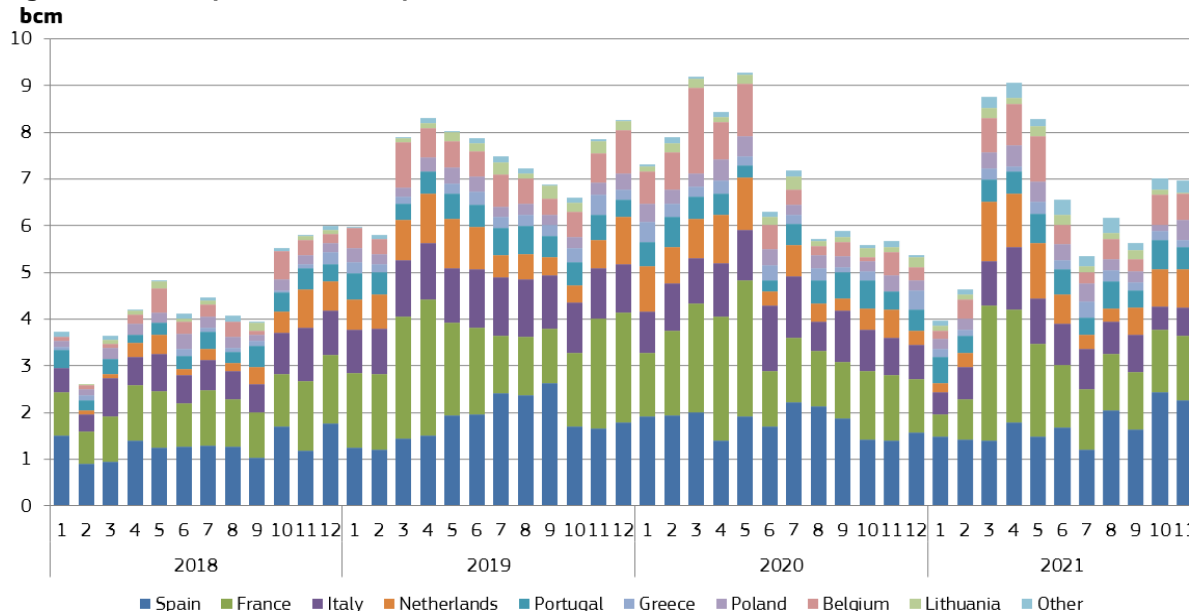
¹⁰ <https://www.reuters.com/article/russia-gas-europe-idINL8N2R01SV>

¹¹ <https://tsoua.com/en/news/in-september-ukraine-increased-gas-imports-from-eu-by-17-to-665-million-cubic-meters/>

1.3.2. LNG imports

- LNG imports in the EU turned down again in Q3 2021 in year-on-year comparison, after stagnating in the second quarter of 2021 and falling during a few quarters before. Looking at the three months of the quarter, EU LNG imports were fell by 26% in July, resurged by 8% in August, however, in September they were down by 4%, compared to the same month of 2020. The quarterly LNG import in Q3 2021 in the EU was 17.1 bcm, lower than in Q2 2021 (23.9 bcm), and down from 18.8 in Q3 2020, as Figure 14 shows. The total number of LNG cargoes arrived in the EU was 245 in Q3 2021, down from 318 in Q2 2021, and from 237 in Q3 2020.
- In Q3 2021, Spain was the biggest LNG importer in the EU, importing 4.9 bcm of LNG, ahead of France, where LNG imports amounted to 3.7 bcm. However, in year-on-year comparison imports were down by 22% in Spain, whereas in France they only decreased by 1%. Italy was the third biggest importer, (with 2.3 bcm, dropping by 24% year-on-year). Portugal came to the fourth place, importing 1.3 bcm (-12% year-on-year), followed by the Netherlands (with the quarterly imports of 1.2 bcm, -9%), Belgium (1 bcm, +16% year-on-year), Poland (0.9 bcm, +18%) and Greece (0.8 bcm, +31%). Among LNG importing EU countries, Finland showed the biggest year-on-year increase in Q3 2021 (+54%), whereas LNG imports fall the most in Malta (-49%), for both countries with imports less than 0.1 bcm of volume. Croatia, starting to import LNG only this year, had a quarterly import of 0.45 bcm in Q3 2021. The total EU LNG imports amounted to an estimated €9.2 billion in Q3 2021, up from €1.6 billion a year before, principally owing to the impact of sharply increasing wholesale gas prices (rising to more than six-fold) year-on-year.
- LNG imports in the United Kingdom fell significantly, by 69% in Q3 2021, reaching only 0.7 bcm in Q3 2021. The number of cargoes berthed in the country was only 1 in both July and August, whereas in September it still reached only 4. During the two summer months, cargoes must have been redirected to other non-European markets. In October and November LNG shipments to the UK picked up again. As LNG berthed in the UK has often continental Europe as final destination, thus low cargo berthing in the UK also result in decreasing LNG send-out in North-western Europe.
- In the first three quarters of 2021, EU countries imported 58 bcm of LNG, which was lower than in the first nine months of 2020 (67 bcm). During this time Spain imported 14.2 bcm, followed by France (13.7), Italy (7.6 bcm), the Netherlands (5.9 bcm) and Belgium (4.6 bcm). In the first nine months of 2021, the UK imported 10.8 bcm of LNG, down from 13.5 bcm in the same period of 2020.
- As in Q3 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 26 and Figure 27). 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.

Figure 14 - LNG imports to the EU by Member States



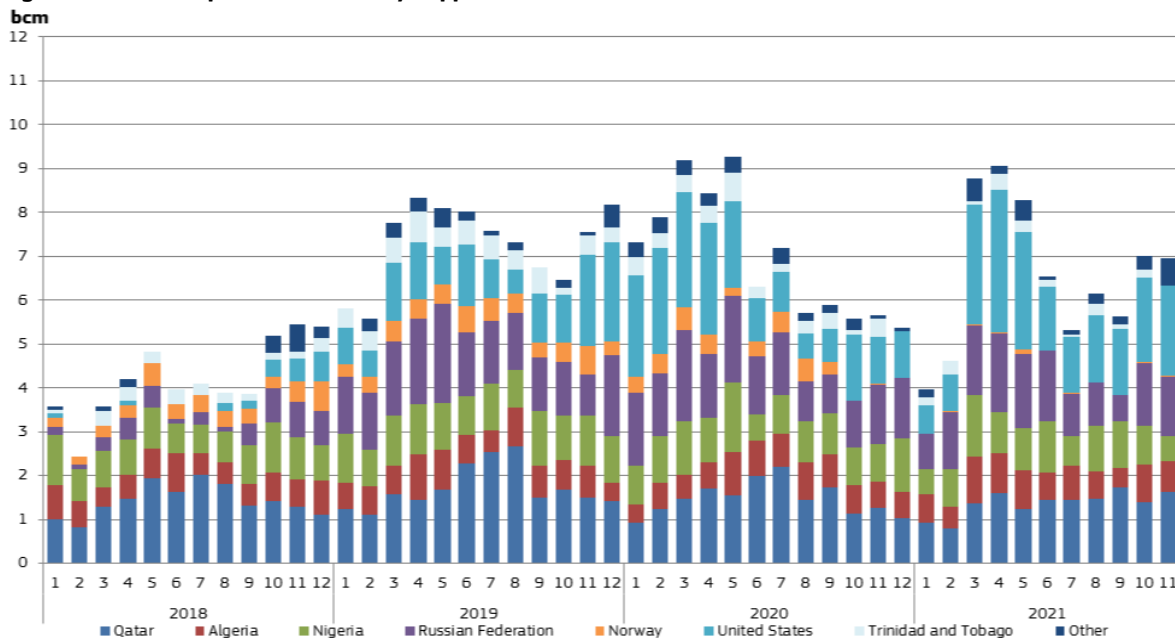
Source: Commission calculations based on tanker movements reported by Refinitiv "Other" includes Finland, Malta and Croatia

- In the third quarter of 2021 Qatar became again the largest LNG supplier of the EU, shipping 4.6 bcm, which was around 27% of the total EU LNG imports. The United States came to the second place, representing 25% (4.3 bcm) in the EU LNG imports. Nigeria was the third most important EU LNG source (with an import share of 16% - 2.8 bcm), pushing Russia only to the fourth in the rank (with 2.5 bcm, 15%). In year-on-year comparison, the share of the Qatar decreased by 2 percentage points, while that of the US

was up by 13 percentage points, practically doubling compared to Q3 2020, which latter period was characterised by massive LNG cargo cancellations, whereas the share of Russia was down by 2 percentage points and that of Nigeria by 1 point. LNG imports from Algeria amounted to 1.8 bcm, and represented 11% of the total imports. Trinidad and Tobago ensured around 2% of the total EU LNG imports – See Figure 15.

- In Q3 2021, Norway had a share of less than 0.3% in total EU LNG imports, similarly to the previous quarter and down from 7% 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. Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022.
- In the first three quarters of 2021, the biggest LNG supplier to the EU were the United States (15.9 bcm), followed by Qatar (12 bcm), Russia (11.3 bcm), Nigeria (8.7 bcm), Algeria (6.4 bcm) and Trinidad and Tobago (1.7 bcm). Other countries shipped LNG to the EU in an amount of 2 bcm during this period.
- The state owned Polish oil and gas company PGNiG signed amendments to agreements with the branches of the American company Venture Global to purchase another 2 million tonnes per annum (mpta) of liquefied natural gas for 20 years¹³. As a result, the volume of LNG contracted from Venture Global LNG by PGNiG will increase up to 5.5 mpta, which equals approximately 7.4 bcm following regasification. The amendments relate to agreements signed by PGNiG and Venture Global LNG companies in 2018.

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

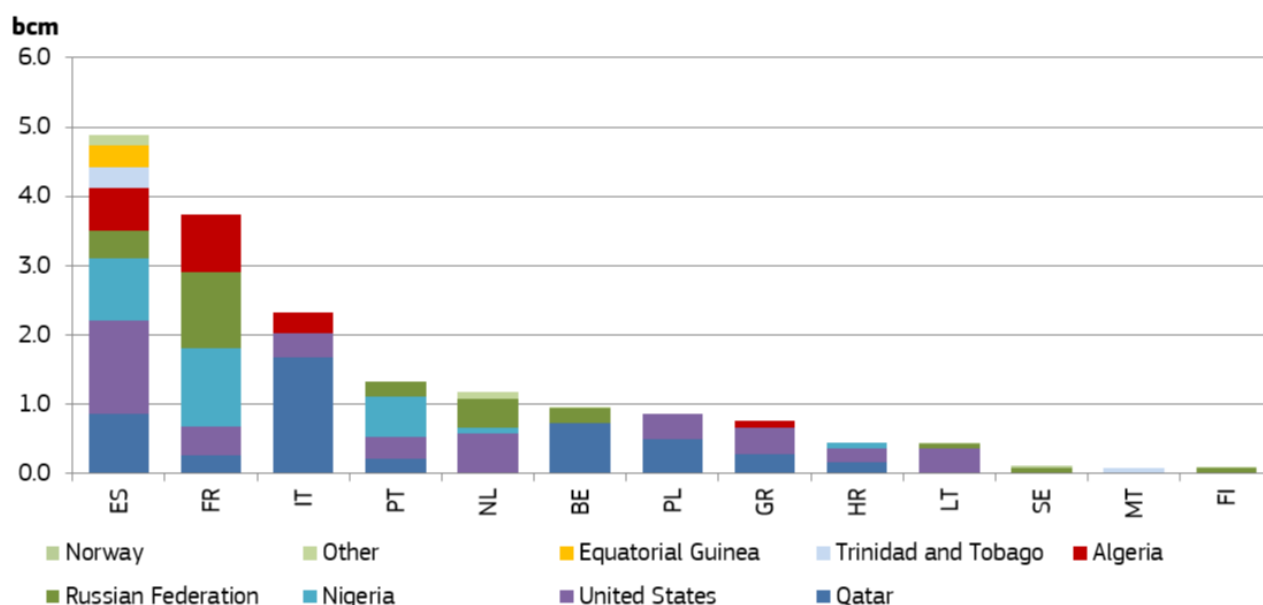
- In the third quarter of 2021, Qatar was the biggest supplier in Italy (72% of the country's total LNG imports), in Poland (56%) and was the second biggest in Croatia (34%). The United States were the biggest LNG supplier in Lithuania (81% of the total LNG imports), in Greece (51%), the Netherlands (50%), Croatia (44%) and Spain (27%), it came to the second place in Poland (44%) and Portugal (25%). Nigeria was the biggest supplier in Portugal (45%), and in France (30%). Russia ensured 97% of LNG imports in Finland and 64% of than in Sweden, while it was the second biggest supplier in the Netherlands (36% of the total LNG import), in France (29%), in Belgium (21%) and in Lithuania (18%). Russian LNG has increasing importance in the EU, especially in North-Western Europe, not independently from the dwindling domestic gas production in the Netherlands.
- Algeria ensured 22% of the French LNG imports in Q3 2021, whereas its share in Italy, Spain and Greek was slightly more than 10% in the LNG supply. Trinidad and Tobago was the sole LNG supplier of Malta in Q3 2021 and had a share of 6% in the Spanish LNG imports. Equatorial Guinea also had a share of 6% in the Spanish LNG supply. Albeit having minimal exports, Norway ensured 36% of the Swedish LNG imports in Q3 2021. Spain had the most diversified LNG import source structure, receiving cargoes from

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

¹³ <https://en.pgnig.pl/news/-/news-list/id/pgnig-will-purchase-more-natural-gas-from-venture-global-lng/newsGroupId/1910852?changeYear=2021¤tPage=1>

eight different countries, followed by France, with five different import sources. On the other hand, Malta had a single supplier of LNG in Q3 2021.

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



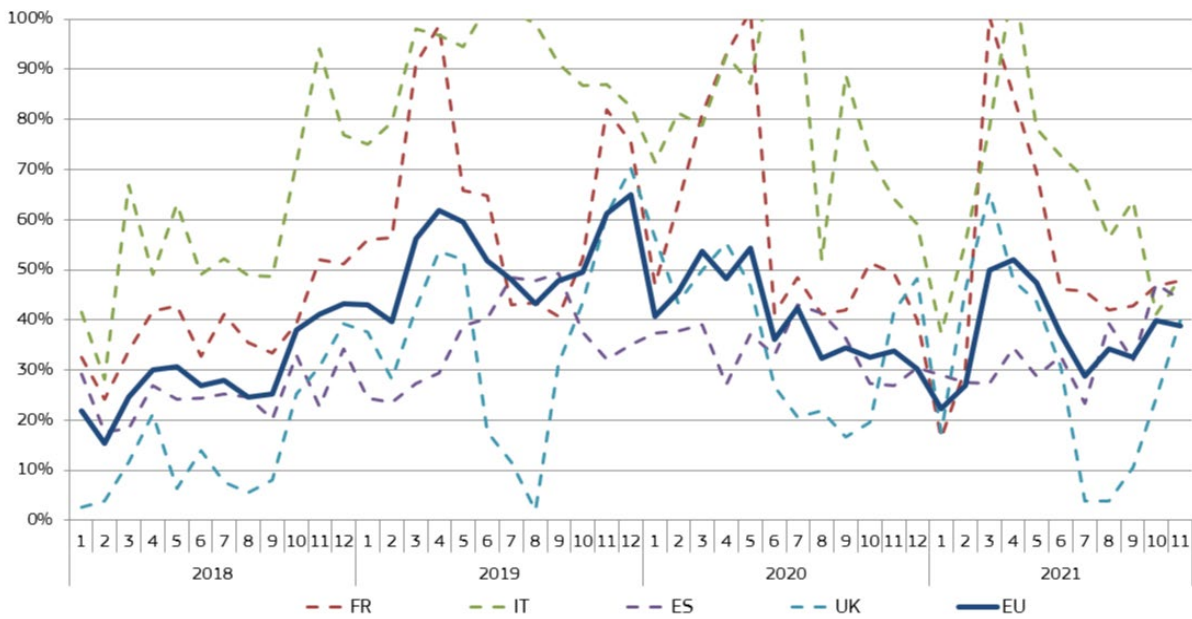
Source: Commission calculations based on tanker movements reported by Refinitiv

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 third quarter of 2021, 49 LNG cargoes arrived in the EU from the US (down from 78 Q2 2021, but up from 24 in Q3 2020). LNG imports from the US amounted to 4.3 bcm in Q3 2021, up from 2.2 bcm in Q3 2020. The estimated market value of LNG imports from the US was around €2.4 billion in Q3 2021. In the first three quarters of 2021, LNG imports from the US amounted to 15.9 bcm, in a monetary value of €5.2 billion.
- LNG exports to Europe represented only 18% of the total US exports in Q3 2021, which was lower than in Q2 2021 (31%), and also lower compared to the share in Q3 2020 (25%). This low share represents the increasing share of Asian destinations in US LNG exports, pointing to more profitable sale of LNG in that higher priced region. In the third quarter of 2021, the three most important EU destinations of the US LNG exports were Spain (1 346 mcm), the Netherlands (579 mcm) and France (425 mcm). The United Kingdom imported only 84 mcm of US LNG in Q3 2021, down from 667 mcm in Q2 2021. In the first nine months of 2021, the share of EU destinations in the total US LNG exports was 22%.
- 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 at 37% in June 2021, remained at low levels in the third quarter of 2021, respectively having 29%, 34% and 33% for the months of July, August and September. In October and November a slight recovery could be observed (with 40% and 39% EU average utilisation rates). 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, even though utilisation rates were higher than the EU average, they decreased in Q3 2021 (in the case of Italy it went down from 73% to 64% between June and September, while at the same time the utilisation rate in France fell from 46% to 42%). Utilisation rates in Spain were above the EU average in August, but below it in July and September, and on quarterly average amounted to 31% in Q3 2021. In the UK utilisation rates were extremely low in July and August (between 3 and 4%) and in September they were still only at 10%, owing to maintenance works on the regasification terminals. In October and November utilisation rates in the UK reached again respectively 24% and 40%.

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 12 August 2021, Polish and Slovak officials confirmed that the implementation of the Poland-Slovakia gas interconnector is underway and around 90% of the project was ready¹⁴. The interconnector has a total length of approximately 164 kilometres and it will be able to transport gas at a capacity of 4.7 bcm per year towards Slovakia or 5.7 bcm per year towards Poland, and in accordance with the plans it will be finalised in the first quarter of 2022. The project, included in the Projects of Common Interest, is an important element of the security of gas supply in the Central Eastern Europe (CEE region), enabling flow of gas between the Baltic and Adriatic regions amongst others.
- After in July 2021, when Germany and the United States reached a deal on Nord Stream 2 pipeline¹⁵, on 26 August the Higher Regional Court of Düsseldorf has rejected Gazprom's complaint against the application of EU rules on competition to Nord Stream 2. As 54 km of the 1,200 km pipeline lie on German territory, it is subject to EU regulation and supervision, according to the German Federal Network Agency (Bundesnetzagentur - BNetzA).
- On 10 September, the sections of the second Nord Stream 2 pipeline laid from the German shore and Danish waters have been connected in a so-called above water tie-in¹⁶, and afterwards the required pre-commissioning activities are to be carried out with the goal to put the pipeline into operation as soon as possible. The new pipeline has the capacity to transport 55 billion cubic metres of gas per year, similarly to the already functioning Nord Stream 1.
- On 13 September, the German energy regulator said that the application of Nord Stream 2 AG for approval as an independent transmission system operator was complete and the BNetzA said it has up to four months as from Sept. 8 to produce a draft decision for the approval¹⁷. Nord Stream 2 AG applied in late June 2021 for the certification with the BNetzA, which has been reviewing the application since then to make sure it was complete. Once BNetzA publishes its draft decision, it then passes to the European Commission, requesting the Commission as prescribed by the amended Gas Directive, to give its opinion before being returned to the German regulator for a final decision, a process that could also take up to four months. Before the final decision, BNetzA would have to take utmost account of the Commission opinion. This procedure does not make realistic of any gas deliveries via Nord Stream 2 before 2022. News around the certification process had a measurable impact on gas wholesale prices in Europe many times during the autumn of 2021.
- Further on Nord Stream 2, on 26 October 2021, the Federal Ministry for Economic Affairs and Energy has completed the supply security analysis in the context of the Nord Stream 2 certification procedure and transmitted it to the BNetzA¹⁸. The analysis concluded that the issuing of the certification does not endanger the security of gas supply in the Federal Republic of Germany and the European Union. The independent nature of the network operation in particular was not subject to the Economic Affairs Ministry's supply security analysis, and the BNetzA continues the certification procedure and examine whether all the other statutory regulatory requirements are met. However, on 16 November, the ruling chamber of BNetzA suspended the certification procedure, caused by a change in legal form at Nord Stream 2 AG¹⁹. The company has decided to fund a subsidiary that is to become the owner and operator of the German part of the Nord Stream 2 pipeline. The new subsidiary now has to fulfil the unbundling requirements of an independent transmission operator.
- On 27 August, production started from the Norwegian Troll phase 3 project in the North Sea²⁰. The project has a break-even price below 10 USD/bbl and CO₂ emissions of less than 0.1 kg per barrel oil equivalent (boe). The new wells are tied in to the Troll A platform and Troll phase 3 will extend the platform's life past 2050. Recoverable volumes from Troll phase 3, which will produce the Troll West gas cap, are estimated at as much as 347 billion cubic metres of gas. Converted into oil equivalent this amounts to 2.2 billion barrels.
- On 20 September, Equinor and its partners have received permission to increase gas exports from two fields on the Norwegian continental shelf²¹ to supply the tight European market. Production permits refer to the gas year 2021 (starting on 1 October), which for each is 1 bcm higher than for the current year, i.e. an increase from 5 bcm to 6 bcm for Oseberg and from 36 bcm to 37 bcm for Troll. After more than 25 years of production, the total recoverable gas volume remaining in Troll phases is estimated to be 715 billion standard cubic metres. These numbers underline the importance of Norwegian gas in the EU gas supply in the forthcoming years.
- On 27 September, Gazprom Export and the Hungarian MVM signed in Budapest two long-term contracts for supplies of Russian gas to Hungary²². Both contracts, which in total envisage supplies of up to 4.5 billion cubic meters of gas per year, will be effective for

¹⁴ <https://ceenergynews.com/oil-gas/a-symbolic-golden-weld-on-the-gas-pipeline-that-connects-poland-and-slovakia/>

¹⁵ See more in the Quarterly Report on European Gas Markets, Vol 14, Issue 2.

¹⁶ <https://www.nord-stream2.com/media-info/news-events/above-water-tie-in-for-the-second-nord-stream-2-string-completed-the-offshore-part-of-the-second-line-is-mechanically-completed-152/>

¹⁷ <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/091321-german-regulator-says-nord-stream-2-certification-application-complete>

¹⁸ <https://www.bmwi.de/Redaktion/EN/Pressemitteilungen/2021/10/20211026-economic-affairs-ministry-transmits-supply-security-analysis-in-nord-stream-2-certification-procedure-to-bundesnetzagentur.html>

¹⁹ https://www.bundesnetzagentur.de/DE/Beschlusskammern/1_GZ/BK7-GZ/2021/BK7-21-0056/BK7-21-0056_Antrag.html?nn=361064

²⁰ <https://www.equinor.com/en/news/20210830-troll-phase-3.html>

²¹ <https://www.equinor.com/en/news/20210920-increasing-gas-export-europe.html>

²² <https://www.gazprom.com/press/news/2021/september/article538440/>

15 years. According to the signatory parties, 'the long-term contracts that were signed today serve as a guarantee of reliable and stable supplies of Russian gas over the next 15 years'. An important component of the new arrangements is the diversification of supply routes. As early as from 1 October 2021, Hungary started receiving Gazprom's gas via Turk Stream and the gas pipelines of south-eastern Europe. 3 bcm of annual flows are estimated to enter to the Hungarian territory, while 1.5 bcm of volume via the HAG pipeline from Austria.

- On 30 September, Algeria gave a guarantee to Spain that gas supplies would be delivered to meet Spanish demand, even if the agreement between Algeria and Morocco on the GME (Maghreb-Europe Gas) pipeline, crossing the latter, was to expire at the end of October²³. Back in late August 2021, Algeria declared that preparations had been made to divert all gas from the GME pipeline into Medgaz subsea pipeline, directly linking Algeria with Spain. Algeria has previously said a number of times that it can meet Spanish gas demand using only its Medgaz line and LNG deliveries. In the first nine months of 2021, GME delivered around 25% of the total annual gas demand of Spain.

1.5 Storage

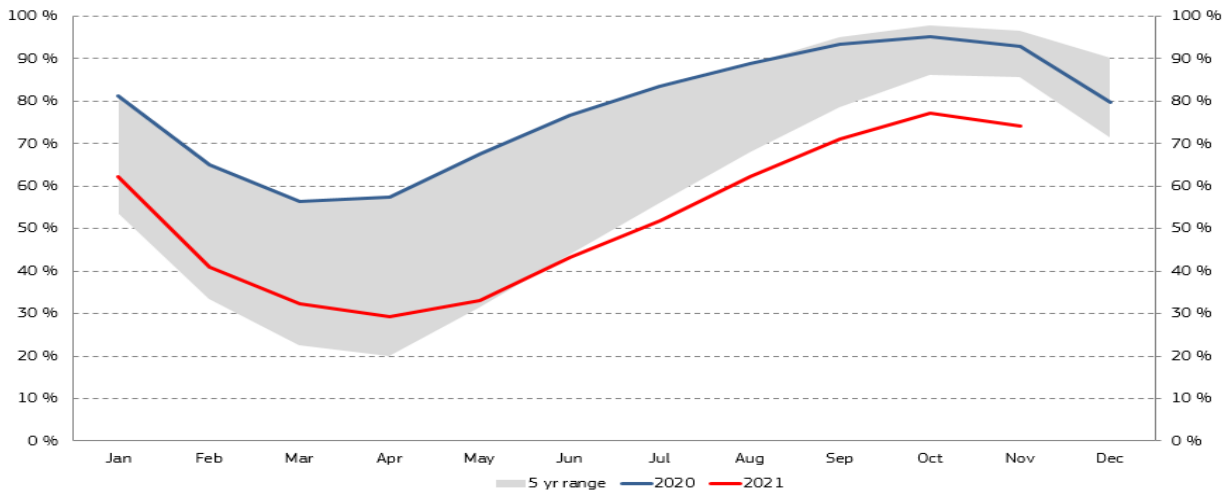
- Figure 18 shows EU stock levels as the percentage of storage capacity in gas years²⁴ 2020 and 2021, compared to the 5-year range of gas years 2015-2019 (gas years 2014-2018). According to figures published by Gas Infrastructure Europe, operational EU storage capacity amounts to 1,148 TWh (roughly 102 bcm) as of July 2021²⁵.
- The third quarter of the year is traditionally the peak season of the refilling period of gas storages, before reaching the peak in October (shoulder month before when storages normally switch from injection to withdrawal), at the beginning of the heating season. During this quarter the filling rates have important influence on prices from the perspective of storage related gas demand, and in the case of significant filling gaps compared to the average of previous years, an upward pressure on prices might occur.
- On 30 June 2021, the average EU storage filling rate was already lower than on the same day of 2020 (47.4% vs. 80.3%), as in the second quarter of 2021 the speed of storage refilling was slower than expected. The average EU filling rate at the end of September 2021 (74.6%) was the lowest at this time of the over the last decade (ranging historically between 81% and 97%). Lower than expected gas inflows from important sources (such as Russia, LNG and in some periods from Norway) resulted in lower supply to inject into storages.
- This was particularly true for storages in the EU operated/used by Gazprom, as in many cases these storages switched to withdrawal to compensate low inflows from Russia (instead of being in injection mode). On 30 September 2021, the EU average filling rate was still 20 percentage points lower than on the same day last year (74.6% vs. 94.7%), even if the gap decreased from 33 percentage points measured at the end of Q2 2021. However, if we compare the daily 2021 storage filling rates during Q3 2021 with the five-year average of the 2016-2020, there was a gap of 15 percentage points both at the beginning and at the end of the quarter. In contrast, Gazprom controlled storages had an estimated average filling rate of 22% on 30 September 2021, in comparison to 91% on this day in the 2016-2020 period on average.
- Ahead of the heating season, EU storages reached the highest fullness rate on 21 October (77.5%), which was around 17% less than in 2020 on the same day of the year and was lower by 14 percentage points compared to the average of 2016-2020 filling rates on this day.
- As Figure 18 and Figure 19 show, since the beginning of the summer, the average EU storage filling rate has been significantly lagging behind the usual values measured in the period of 2011-2020. Increasing wholesale spot gas prices and shrinking winter-summer spreads for the forthcoming year did not provide incentives for rapidly refilling storages.

²³ <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/102121-spanish-importers-nominate-zero-algerian-gas-imports-via-gme-link-for-nov-enagas>

²⁴ 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

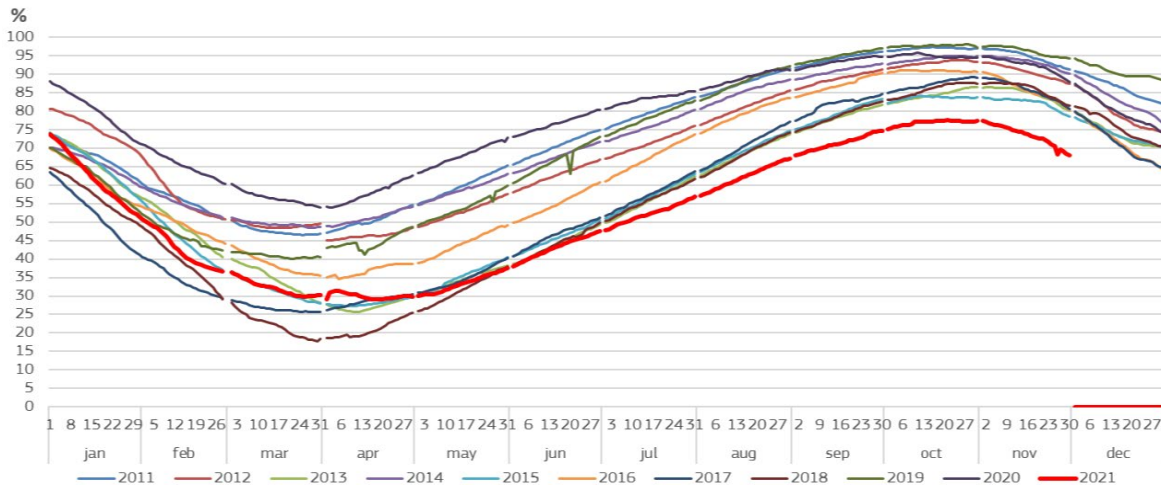
²⁵ https://www.gie.eu/wp-content/uploads/filr/1410/2021_Storage_DB_final.xlsx

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



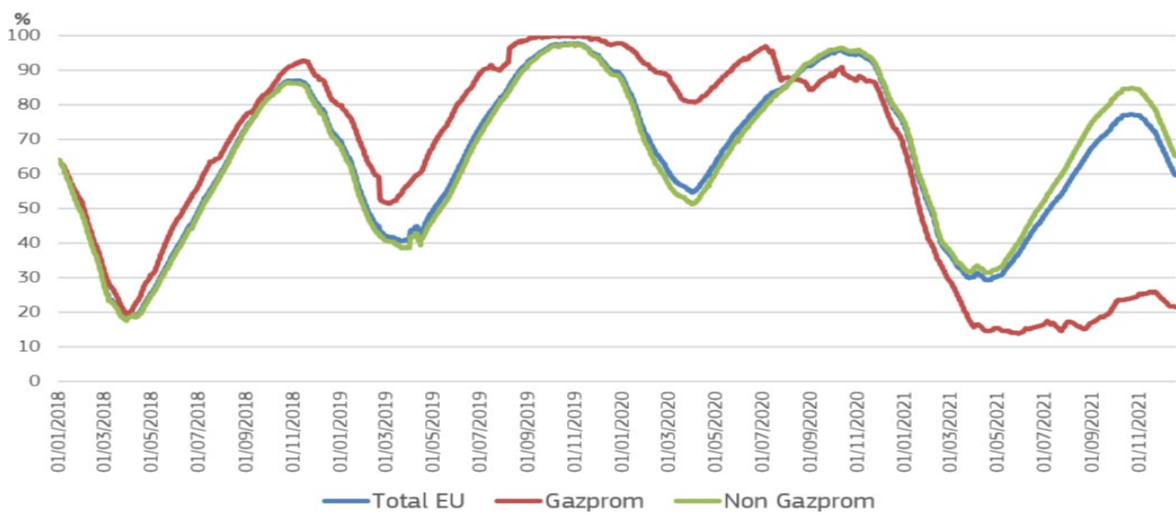
Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 2 December 2021. See explanations on data coverage at <https://agsi.gie.eu/#faq>. The 5-year range reflects stock levels in years 2015-2019. The graph shows stock levels on the 15th day of the given month.

Figure 19 – Daily gas storage levels in the EU on average in per cent of total available storage capacities



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 2 December 2021. See explanations on data coverage at <https://agsi.gie.eu/#faq>.

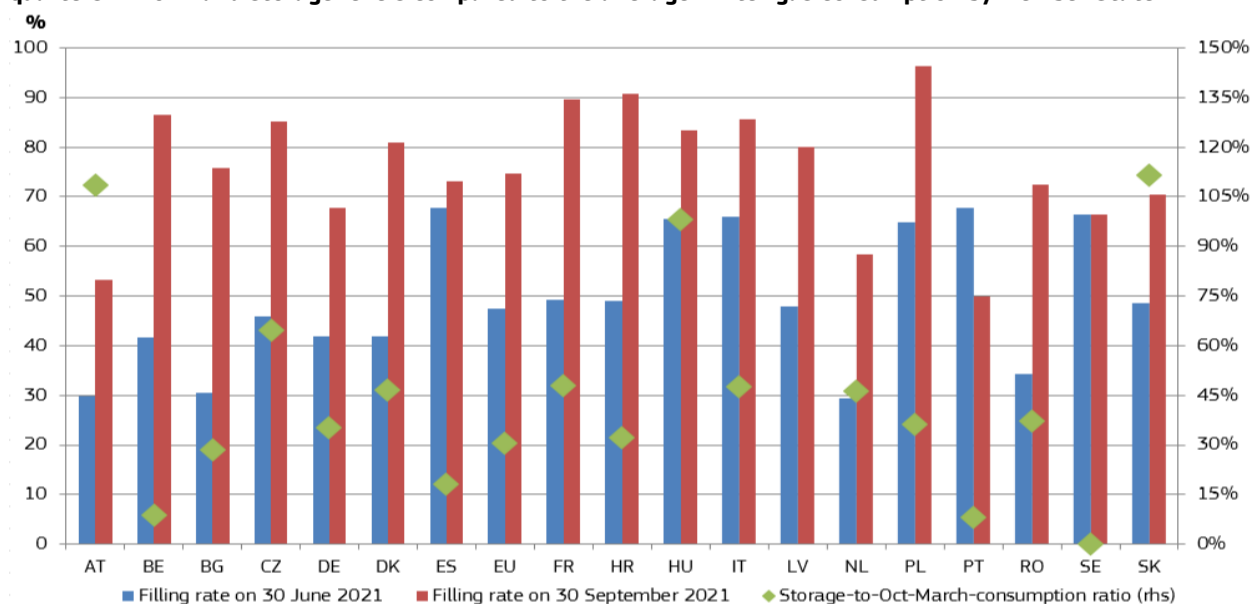
Figure 20 – Difference in the filling rates of Gazprom controlled storages and other storages



Source: JRC calculations, based on Gas Storage Europe AGSI+ data

- As Figure 21 shows, on 30 June 2021, storage filling rates across the EU Member States ranged from 29% in the Netherlands and 30% in Austria to 60% in Spain, reaching 47% on EU average. The EU average filling rate was 75% on 30 September 2021, with the lowest filling rates in Portugal (50%), Austria (53%) and the Netherlands, (58%), whereas the highest fullness rates could be observed in Poland (96%), Croatia (91%) and France (90%).
- The highest injection rates (between 30 June 2021 and 30 September 2021) could be observed in Belgium, Croatia and France (respectively 45, 42 and 40 percentage points), whereas in Spain filling rates only increased by 5 percentage points, in Sweden (though having minimal storage capacities) filling rates did not change over Q3 2021, and interestingly, in Portugal they even decreased by 18 percentage points.
- Beyond the evolution of filling rates over time, it is worth to take a look at the relation between the amount of gas in storages, and the average winter consumption in different markets. At EU level, on 30 September the amount of stored gas covered around 30% of the average gas consumption of the 27 countries in the last five years. In Latvia, Slovakia and Austria the storage coverage rate of the winter consumption was above 100%, and in Hungary it was close to 100%. On the other hand, in Belgium and Portugal the coverage rate was less than 10% and in Sweden it was below 1%. However, it is important to recall that a measurable part of gas stored underground cannot be recovered, as under a certain level (cushion gas) the pressure is not sufficient to withdraw gas, so in reality the coverage rate is lower than these data would suggest. On the other hand, gas markets are of regional nature, and countries with high gas storages may supply neighbouring markets as well. The speed of withdrawal depends on weather conditions, gas import flows and market prices as well.

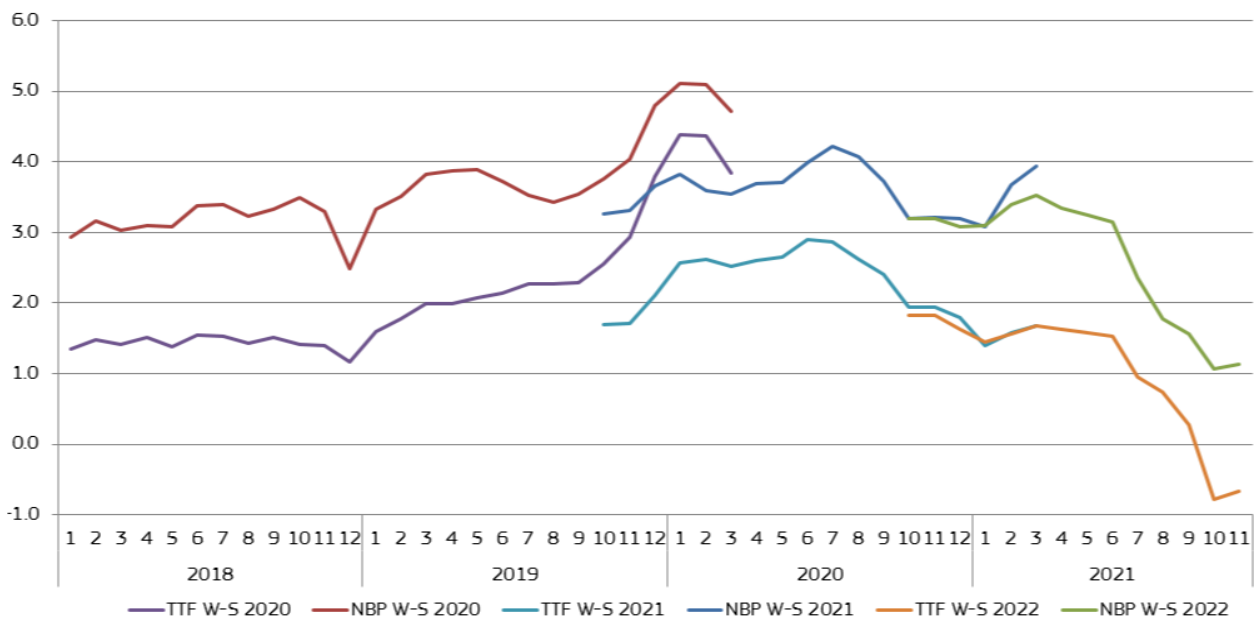
Figure 21 - Gas storage levels as percentage of maximum gas storage capacity at the end of the second and third quarters in 2021 and storage levels compared to the average winter gas consumption by Member State



Source: Gas Storage Europe AGSI+ Aggregated Gas Storage Inventory, extracted on 2 December 2021. See explanations on data coverage at <https://agsi.qie.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.

- The next two charts (Figure 22 and Figure 23) show the winter-summer spreads, as depicted by the difference in the 2021 and 2022 summer and winter contracts. Although 2021 seasonal spreads ran out at the end of March 2021, they provided an indication for the incoming 2022 spreads.
- On the TTF, 2022 seasonal spreads were at 1.5 €/MWh in June and continued to fall during the summer, reaching 0.3 €/MWh in September 2021. Later in the year, in October and November 2021, seasonal spreads turned into negative range (-0.8 €/MWh and -0.7 €/MWh respectively). This is a quite rare phenomenon, and it must have been related to the strong backwardation position of the European gas market, as winter 2022 contracts became cheaper than summer 2022. These negative spreads do not give much incentives for the future to refill storages.
- At the same time, the seasonal spread on the NBP hub fell from 3.1 €/MWh in June to 1.6 €/MWh in September 2021, decreasing further to 1.1 €/MWh in October and November. NBP winter-summer spreads had a premium of 1.2 €/MWh over the TTF spreads in Q3 2021.

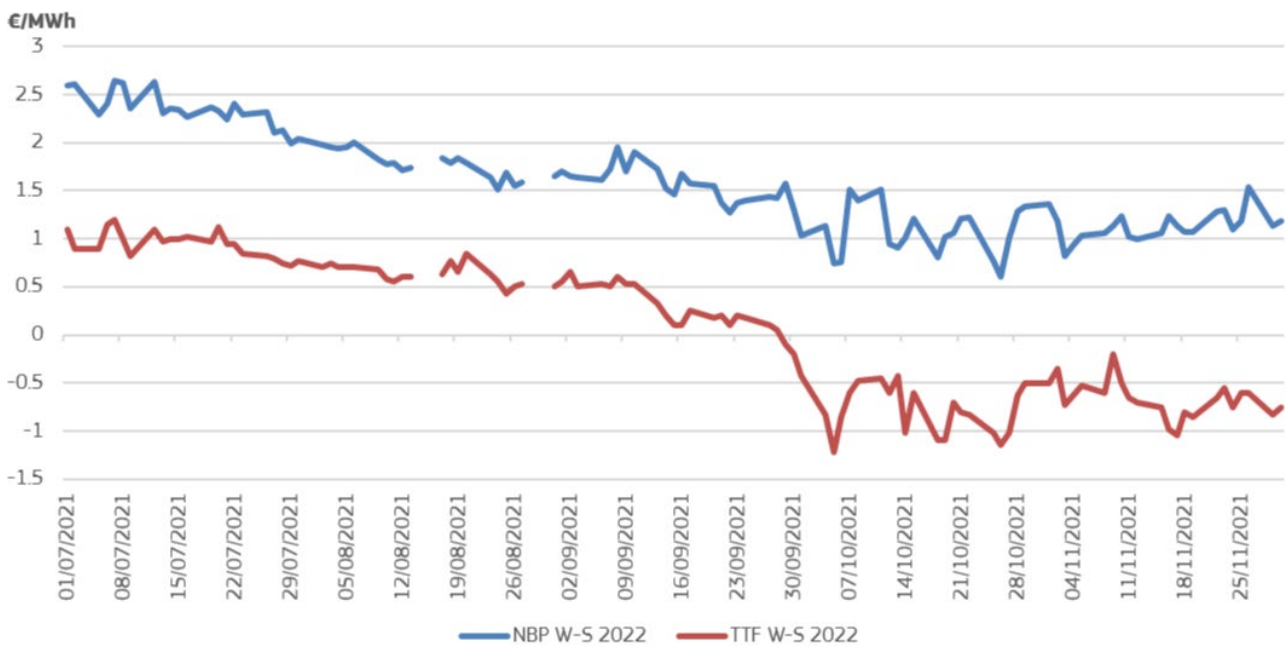
Figure 22 - Winter-summer spreads on the Dutch and British gas hubs
Euro/MWh



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.

Figure 23 - Daily winter-summer spread on the Dutch TTF hub



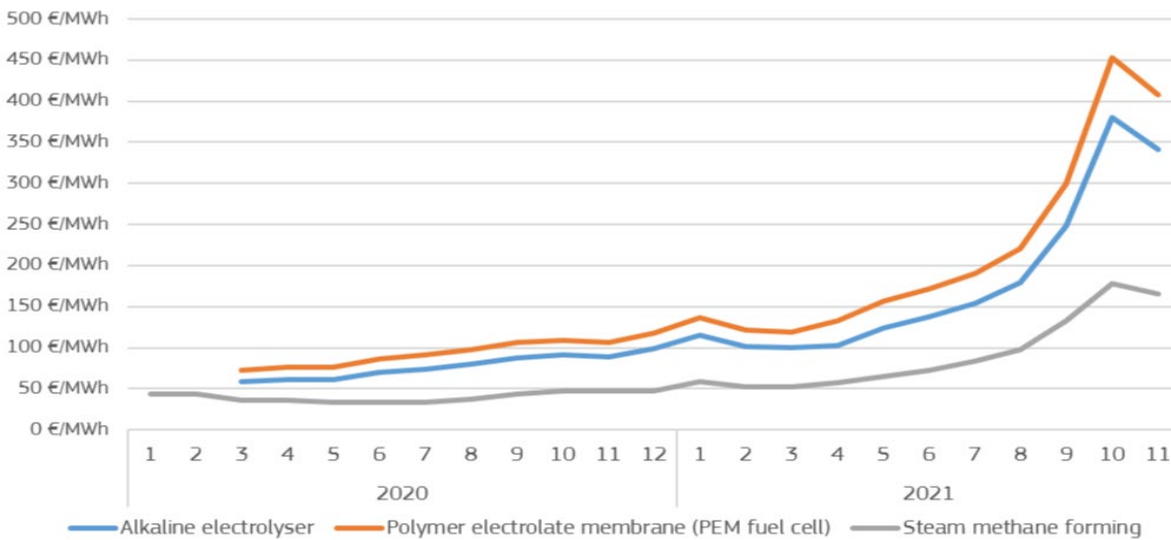
Source: S&P Global Platts

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 24 - 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 July 2021 the TTF spot gas hub prices averaged at 36.2 €/MWh, rising to 44.3 €/MWh in August, and further to 64.6 €/MWh in September 2021. At the same time, the Pan-European Electricity wholesale price was around 83.7€/MWh in July, rising to 90.5 €/MWh in August and to 141.6 €/MWh in September 2021. In October and November 2021 both wholesale gas and electricity prices reached new highs in the EU markets. The significant increase in wholesale gas and electricity prices over the last few months also resulted in increasing hydrogen price assessments.
- Cost-based assessment price for alkaline technologies rose from 154 €/MWh in July to 248 €/MWh in September (and to 380 €/MWh in October, with CAPEX costs), whereas prices of PEM fuel cell technology based generation rose from 191 €/MWh in July to 300 €/MWh in September (and to 453 €/MWh in October). These cost assessments were about twice as high as wholesale electricity prices. At the same time, SMR technology based costs assessments rose from 83 €/MWh in July to 98 €/MWh in August, and to 133 €/MWh in September (and further to 178 €/MWh in October), 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 gas prices and rising carbon prices, as gas is the most common price setter on wholesale electricity markets.
- On recent project initiatives, in September 2021, the Slovak transmission system operator, EUSTREAM announced to join the international industry partnership for the production and supply of green hydrogen "H2EU+Store"²⁶. Hydrogen from sun and wind will be produced in Ukraine, transported via EUSTREAM's network to Austria and Germany and stored for seasonal demand in Central Europe in the future. The initiative focuses on the complete supply chain of clean hydrogen including hydrogen production in Ukraine and transport via EUSTREAM's network to Austria and Germany. "H2EU+Store" will on the one hand create the necessary capacities for renewable electricity and hydrogen production in Ukraine and on the other hand the expansion of storage volumes in Austria and Germany, accompanied by adaptations in the area of gas transport to Central Europe.

²⁶ https://www.eustream.sk/en_media/en_news/eustream-has-joined-the-international-partnership-h2eustore-for-the-production-and-supply-of-green-hydrogen

- Further on hydrogen in the Central Eastern European region, four companies, namely include EUSTREAM (the Slovak gas TSO), Gas TSO of Ukraine (GTSOU), NET4GAS (the Czech gas TSO) and OGE (a leading German gas TSO) have joined forces to develop a hydrogen highway through Central Europe called the Central European Hydrogen Corridor²⁷, enabling to transport green hydrogen from Ukraine through Slovakia and Czechia to Germany. The project promoters have already started to explore the technical feasibility of creating a Central European Hydrogen Corridor for the transportation of up to 120 GWh per day of pure hydrogen from Ukraine to Germany by 2030.

1.7 Focus on: The response from the European Union and its Member States on high gas prices

- Wholesale energy prices, especially for gas and electricity, underwent a significant increase since the beginning of the second quarter of 2021 in the EU and in other parts of the world. By early October, both gas and electricity wholesale spot prices on the European markets have reached highs not seen since the beginning of wholesale energy trade in Europe. High wholesale prices have impacted a significant element, the energy costs of the retail gas and electricity prices and thus consumer bills. By early autumn of 2021 energy prices, and their expected increase became an issue of high interest in most of the EU Member States.
- On 13 October 2021, the European Commission, in response to the sharp spike in energy prices, resulting in a high concern for citizens, businesses, the European institutions and governments all over the EU, adopted a toolbox²⁸ to help and support addressing the negative impacts on households and businesses. As the energy price spike weighs on households' purchasing power and the competitiveness of businesses, it requires a rapid and coordinated policy response, which should prioritise tailored measures that can rapidly mitigate the effects on vulnerable groups. The measures adopted should easily be adjusted when the situation improves for these groups and avoid interfering in market dynamics or dampening incentives for the transition to a decarbonised economy.
- The toolbox includes proposed measures on different time horizons, notably immediate and mid-term measures. Among the immediate measures to protect vulnerable customers, there are proposals for income support for households in need, temporary deferral of bill payments, safeguards to avoid disconnection from the grid, reduced taxation targeted for poor or vulnerable customers. Further measures include shifting renewable support scheme levies away from energy bills, aid to companies in line with EU state aid rules etc.
- The toolbox includes further medium-term and long-term measures, such as increasing investment in renewable energy, developing energy storage capacities, stepping up investments in energy efficiency and building performance, investments in energy grids, improving the EU's energy system resilience, consumer empowerment, and the setting up of an Energy Poverty Coordination Group.
- On 26 October 2021, EU energy ministers welcomed²⁹ the Commission's "toolbox" as a good basis for the discussions and generally supported the Commission's analysis of the causes of the spike in energy prices. Regarding short-term measures, ministers agreed that national measures have to be taken as a matter of urgency to shield the most vulnerable consumers.
- This chapter of the current gas report focuses, beyond the short presentation of the Commission toolbox on what kind of measures Member States have already taken to respond to high energy prices, specifically on the wholesale and retail gas sector. Gas prices also impact electricity generation and thus retail electricity prices, costs for households and businesses, however, in the current gas report only the direct impacts on consumers have been addressed. However, some actions and measures mentioned here might also be applicable for energy other than gas (e.g. electricity, district heating).
- Most of the measures already taken by the Member States to address the increasing gas prices³⁰ seem to fall under the categories mentioned in the toolbox proposed by the Commission. One of the most common measures applied by Member States is providing financial support to households (in the form of funds, energy vouchers, etc.). Belgium expanded its fund for gas and electricity, to provide additional financial help for households not eligible for social tariffs. Estonia is planning to partially compensate, from January 2022, the increase in gas prices with payments for vulnerable householders, covering the period of September 2021 to May 2022. Greece, Spain and France also offered in 2021 vouchers and subsidisation of household energy consumption. Italy has decided to strengthen the social bonus on households' energy bills. The Netherlands announced a budget for targeted energy savings for vulnerable households.
- Reduction of taxes, principally energy taxes, levies and VAT applicable for household gas (and other energy) customers was also among the most common actions. Italy also announced a VAT reduction on gas (down to 5%) from October to December 2021 and prolonged it until March 2022, similarly Poland announced a VAT reduction on natural gas from 23% to 8% (effective from January to March 2022). The Netherlands announced a one-off temporary package including reduction of energy taxes in 2022 for households and small and medium-sized businesses.

²⁷ <https://www.cehc.eu/en/news/the-central-european-hydrogen-corridor-initiative.html>

²⁸ <https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52021DC0660&from=EN>

²⁹ <https://www.consilium.europa.eu/en/meetings/tte/2021/10/26/>

³⁰ Measures mentioned here reflect information available for the Commission until the beginning of December 2021, Member States might impose further actions in a later stage.

- Some Member States opted for reducing, or capping the increase in, retail gas prices and/or introducing deferred payments for higher tariffs. France announced that gas regulated prices will be capped at the level after the last increase in October, until the end of June 2022, and foregone revenues of gas suppliers will be compensated by the state budget. In Lithuania, price increases for end-users will be distributed over a certain period of time (for gas up to 5 years).
- There are other individual measures in some Member States. In Belgium, the Flemish regional government has limited natural gas connection fees in Flanders to 250 €. In Greece, payments for network use have been postponed for industry and other activity using the medium-voltage network (November 2021–April 2022). In Spain, the so-called last resort rate for gas has been modified until April 2022, protecting small consumers, with the aim of mitigating the impact of extreme increases in the cost of gas. In Hungary, though independent from the current energy spike, there are measures prohibiting the disconnection of households during winter season (November–April).
- In parallel with measures taken by the Member States alleviating consumer burdens, in some cases security of supply issues might also make necessary for national authorities to take steps to ensure the continuity of retail energy service. For example, on 12 October 2021, E.ON (EONGn.DE) became the first German major energy supplier to suspend temporarily new natural gas supply contracts for new residential customers. On 13 October, Bohemia Energy, the largest alternative electricity and gas supplier in Czechia, halted operations. On 7 December Vlaamse Energieleverancier³¹, an alternative energy supplier operating in the Flemish region of Belgium declared bankruptcy and 70 thousand customers have to be supplied temporarily by Fluvius, a local DSO. These examples show that rapidly increasing wholesale prices already started to impact to operation of retail utilities, and when the increase of energy purchase costs cannot be realised in the final contracts, this would easily lead to the limitation or even to termination of activities.

2. Wholesale gas markets

2.1 EU energy commodity markets

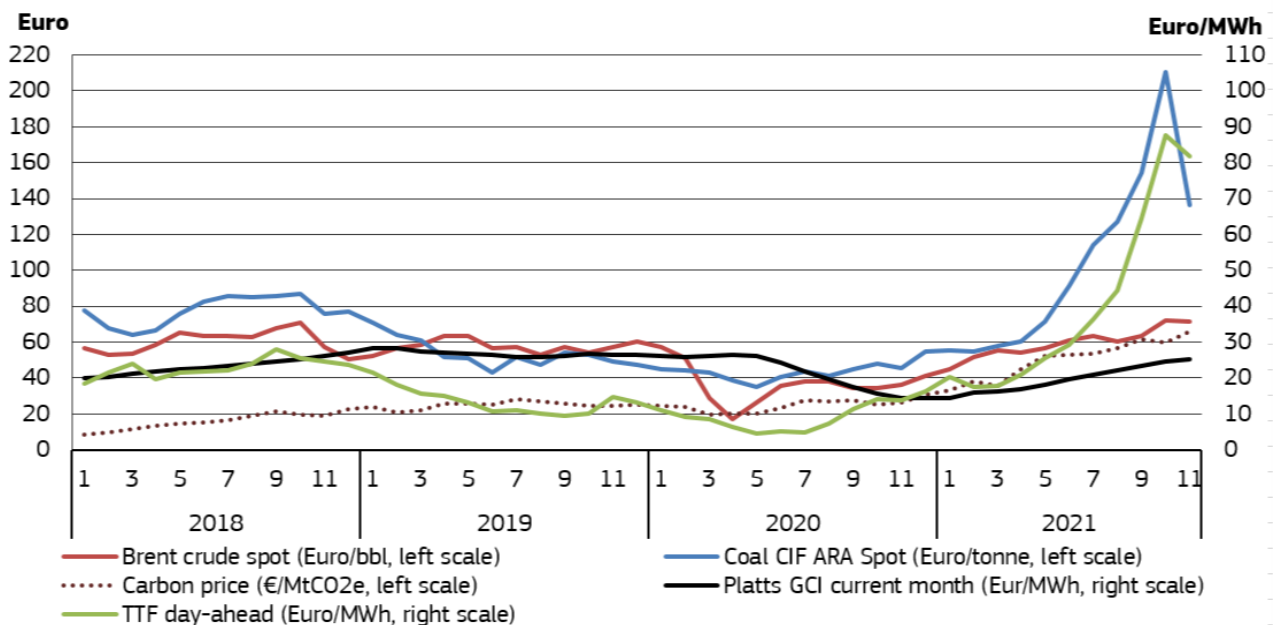
- The dated Brent crude oil price kept remained in the range of 66-80 USD/bbl (58-68 €/bbl) in the third quarter of 2021. In the following two months oil prices rose above 80 USD/bbl (71-72 €/bbl in October and November 2021), and late October they rose to 86 USD/bbl (74 €/bbl), which were the highest since 2014. The demand side of the oil market was principally impacted by news on Covid-related restrictions, and the recovery of the global economy. On the top of this, high gas prices inflicted increasing demand for oil in power generation in some countries (mainly outside Europe). On the supply side, OPEC+ countries, after several rounds of negotiations during the summer, managed to agree on 18 July on a monthly increase of their production by 0.4 mbdp in each month as of August, reevaluating the situation at the end of 2021, and on the complete phase-out of the April 2020 production adjustments by May 2022. Oil supply was impacted by the production loss in September by Hurricane Ida in the US, and rapidly decrease oil and petroleum stocks in the OECD countries, two factors also resulting in tightness of oil supply. The recovery of oil production in the US has been slower than expected in 2021 so far, and it is expected to fully recover only in 2022, which might also help in stabilizing oil prices. Over the course of Q3 2021, the discount of the year-ahead contract was around 6-8 USD/bbl (5-7 €/bbl), signaling a market expectation for correction of the spot price increase.
- The Dutch TTF spot gas price continued its sharp increase started the second quarter of 2021, and over Q3 2021 it rose from 36 €/MWh to 85 €/MWh. At the beginning of October, the TTF spot daily average rose to the highest ever (116 €/MWh on 5 October, though during the intraday session the price shot even up to 160 €/MWh). During the autumn months TTF spot hub prices remained quite volatile, driven by news on weather, storage levels, gas import flows, renewables availability and geopolitical news from gas source and transit countries.
- The unprecedented price increase in European hub prices over the summer and autumn months of 2021 were mainly linked to supply tightness, but to global demand factors as well. LNG gas prices in the Asian markets continued to retain their premium vis-à-vis Europe, still ensuring higher profitability to sell LNG on these markets that put a limit to LNG inflows in Europe. As of Q3 2021, just a few months ahead of the winter heating season, low fullness of gas storages in European countries started to raise concerns on gas security of supply, which contributed to the upward trend in prices. The average filling rate across the third quarter of 2021 was around 15% lower compared to the average of the five preceding years, and this gap did not close over the quarter and remained since the beginning of October as well. After the regular maintenance season of Nord Stream and Yamal pipelines in July 2021, on 5 August following an accidental outage in the gas condensate plant in Novy Urengoy in Russia, flows on Yamal dropped back significantly and recovered only by the end of August. In September, there were maintenance works on Norwegian infrastructure, limiting gas imports from Norway. Over the summer and autumn months, Gazprom booked less additional capacities on several interconnection points, as Russia had intention to first fill up their domestic storages, before supplying European customers. This also resulted in withdrawing gas from Gazprom owned storages in European countries, increasing the storage filling gap compared to the seasonal averages. News around the permission process of the Nord Stream 2 pipeline, whose physical construction was finished in September, also contributed to price volatility of European gas markets. On the demand side, in Q3 2021 there were many periods when wind and solar production was lower than expected and missing power generation had to

³¹ <https://www.vrt.be/vrtnws/nl/2021/12/06/na-het-faillissement-van-vlaamse-energieleverancier-kan-het-lic/>

be complemented from gas-fired generation, increasing demand for gas on an already tight market. However, too high gas prices started to put solid fuels, mainly lignite, back in power generation in many EU markets. Over Q3 2021, the discount of year-ahead TTF contracts to the spot continued to widen, up from 9 €/MWh at the beginning of July to 26 €/MWh at the end of September). The gas market was in a strong backwardation, signaling that the market anticipates a correction in the spot contracts in the following period, though year ahead contracts also underwent a significant increase, implying that the market will not likely to quickly return to the price levels seen in the first half of 2021 and in earlier years.

- Platt's North West Europe Gas Contract Indicator (GCI), a theoretical index showing a gas price linked 100% to oil, continued to increase in Q3 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 19.6 €/MWh in June 2021 to 23.5 €/MWh in September 2021 (and rose slightly further to 24-25 €/MWh in October and November, showing signs of a temporary halt and reaching plateau). In Q3 2021, and further in the autumn months, 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 Q3 2021 year-on-year). GCI is expected to only slightly rise in the forthcoming months, as the price increase in the oil market, though reaching highs in Q4 2021, must have been largely priced in. 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 few quarters.
- Spot coal prices (CIF ARA) increased sharply during the third quarter of 2021, starting month of July at 105 €/Mt, and finishing September 2021 at 190 €/Mt. In October 2021, coal prices rose above 250 €/Mt, around twice as high as the record high levels seen in 2008, before starting to fall back later in the autumn. On the demand side, increasing demand in China and India for seaborne coal was driving the market, as high gas prices made coal-fired generation competitive. At the same time, the market faced coal supply problems at several parts of the world: news on a railway bridge collapse in Russia, industrial activity (strike) in Colombia and floods in Indonesia all contributed to the supply tightness of the coal market. In China flat domestic production was coupled with increased global demand, and rumors on lifting coal import ban from Australia also fueled the demand side of the market.
- Carbon prices in the third quarter of 2021, in parallel with energy commodities prices, extended their increase of the previous quarter, up from 57 €/MtCO_{2e} to 61 €/MtCO_{2e}. During October and November, similarly to the peaks of gas, coal and electricity, carbon prices reached new highs, rising to 75€/MtCO_{2e} by the end of November 2021. Increasing carbon prices had an adverse impact on coal-gas switching, as gas became too costly for generating power in many countries with efficient solid fuel power plants are on the grid.

Figure 25 - Spot prices of oil, coal and gas in the EU

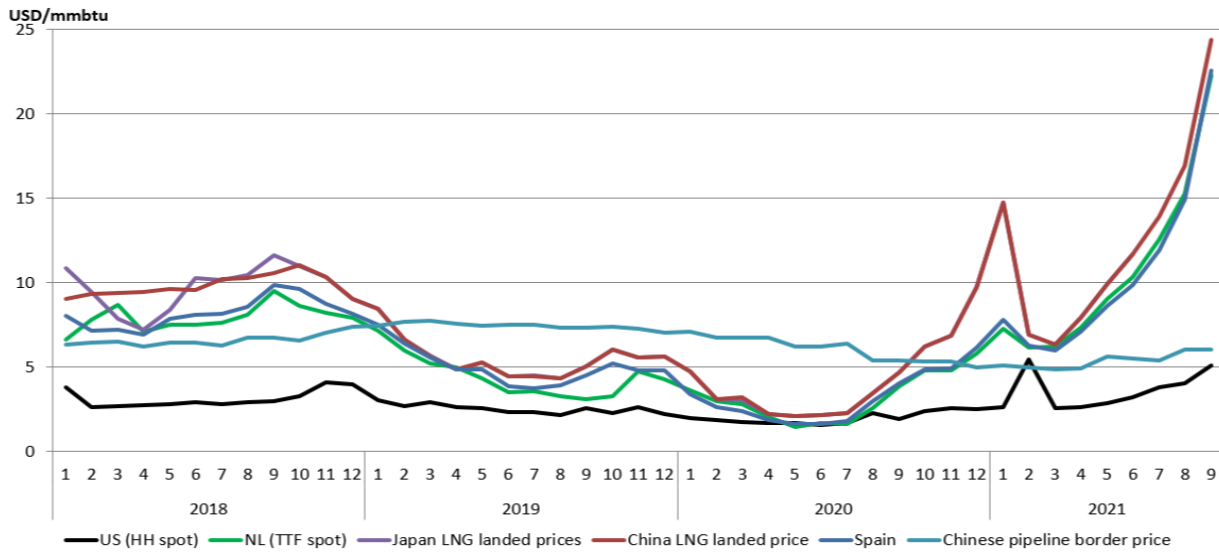


Source: S&P Global Platts

2.2 LNG and international gas markets

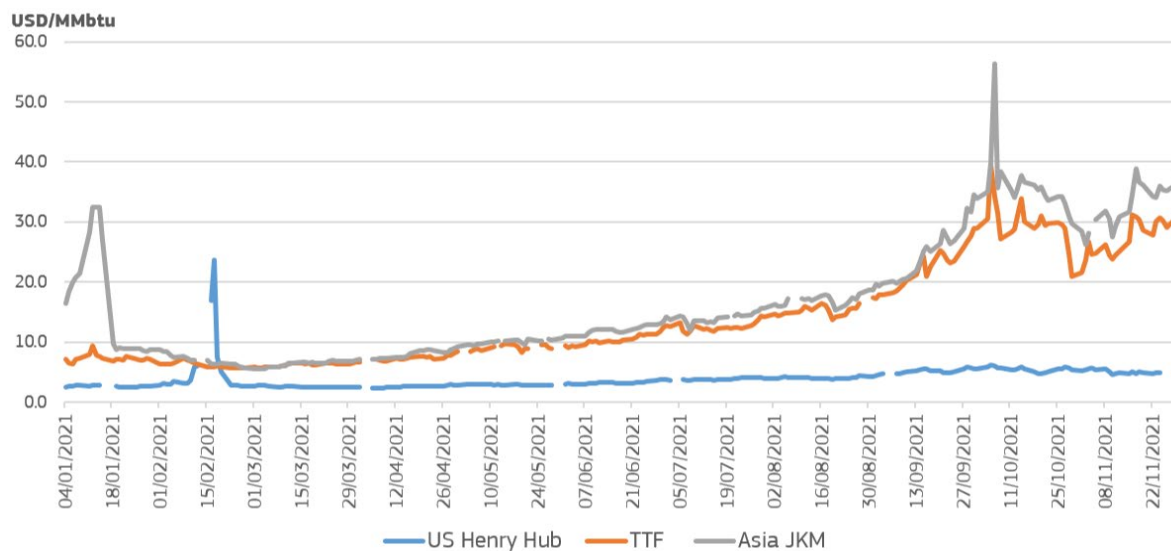
- Figure 26 displays the international comparison of wholesale gas prices, including hub, LNG landed and pipeline import gas prices. Since the beginning of March, Henry Hub prices in the US began to increase, as gas demand in Asia became a global factor, providing profitable LNG sell opportunities in Asia for US gas producers. In September 2021, Henry Hub reached the same price level on monthly average as during the price spike in February. Meanwhile, Asian contracts continued their sharp increase and by September 2021 they rose to four times as high as the Henry Hub monthly average.
- The average Japanese LNG price was 18.4 USD/mmbtu in Q3 2021, almost doubling from 9.9 USD/mmbtu in Q2 2021, and reaching more than five times as high as in Q3 2020 (3.5 USD/mmbtu). The Japanese premium above the Dutch TTF hub was on average 1.7 USD/mmbtu in Q3 2021, up from 1 USD/mmbtu in the second quarter of 2021 and up from 0.8 USD/mmbtu in Q3 2020. On quarterly average, LNG import prices in China were comparable with their Japanese peers (18.4 USD/mmbtu in Q3 2021). It seems that the Asian premium to the TTF (1.7 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 5.8 USD/mmbtu in Q3 2021, having a significant price advantage vis-à-vis LNG imports (with the aforementioned quarterly average price of 18.4 USD/mmbtu in Q3 2021). However, similarly to European oil-indexed gas contracts, the time-lagged impact of increasing oil prices as of mid-2020 started to appear in import gas prices. 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 rose to 4.2 USD/mmbtu in Q3 2021 up from 2.9 USD/mmbtu in Q2 2021 and from 2.0 USD/mmbtu in Q3 2020. As Figure 27 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 (12.4 USD/mmbtu and 14.1 USD/mmbtu), which provided perfect opportunities for US LNG exporters. However, increasing domestic gas prices in the US raised concerns on potential export restrictions. The euro slightly depreciated against the USD in Q3 2021 (in June 2021 the exchange rate was 1.20 while in September 2021 it was 1.18), but this did not really contribute to the increasing divergence between the TTF and the Henry Hub.
- In the third quarter of 2021, in parallel with increasing absolute differentials, price ratios of international contracts showed mostly further increases. The average TTF/Henry Hub ratio was 3.9, up from 3.1 in Q2 2021 and from 1.4 in Q3 2020. The ratio of the Japanese LNG price and US Henry Hub was 4.3 in Q3 2021, rising from 3.4 in Q2 2021, and from 1.4 in Q3 2020, whereas the average price ratio of the Japanese LNG prices and the TTF was 1.1 in both the second and the third quarters of 2021, slightly down from 1.3 in Q3 2020.
- In the third quarter of 2021, TTF averaged at 16.7 USD/mmbtu (48.4 €/MWh), up from 8.9 USD/mmbtu (25.2 €/MWh) in Q2 2021 and, after 2.7 USD/mmbtu (7.8 €/MWh) in Q3 2020. The average German border price in Q3 2021 was lower than the TTF (8.4 USD/mmbtu or 24.2 €/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 third quarter of 2021, the Dutch TTF spot price averaged at 16.7 USD/mmbtu, the Spanish LNG landed price was 16.5 USD/mmbtu, and that in China and Japan reached 18.4 USD/mmbtu.
- The JCC (Japanese Crude Cocktail) contracts reached 10.8 USD/mmbtu in the third quarter of 2021 on average, up from 8.7 USD/mmbtu in Q2 2021 and from 7.2 USD/mmbtu in Q3 2020, and were significantly lower than Japanese LNG import prices (18.4 USD/mmbtu), and the TTF (16.7 USD/mmbtu) as well.

Figure 26 - International comparison of wholesale gas prices



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

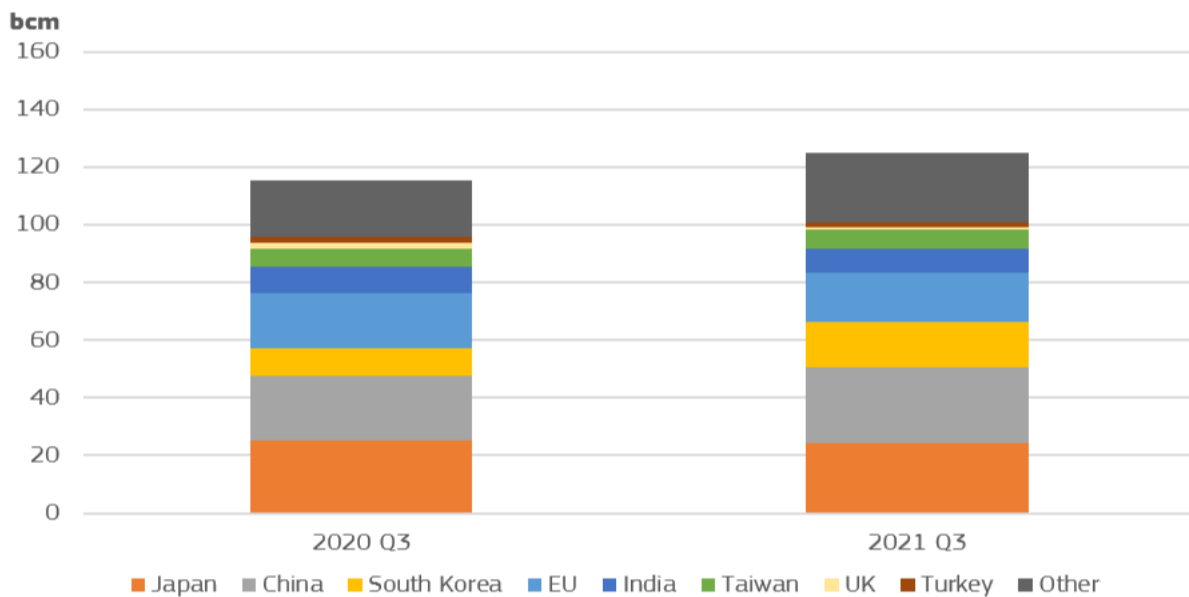
Figure 27 – Daily average prices on the TTF (Dutch), the US Henry hub and the JKM Asian reference index



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 Q3 2021 China retained the biggest global LNG importer position ahead of Japan, with quarterly imports amounting to 26 bcm, out of the total estimated 125 bcm market. Japan imported 24.5 bcm, whereas the EU (as 27 countries) had a quarterly LNG import of 17 bcm, followed by South Korea (16 bcm), India (8 bcm), Taiwan (constituting a separate market, with an import volume of 7 bcm) and Turkey (1.8 bcm). Compared to the third quarter of 2020, a significant increase could be observed in in South Korea (63%, +6 bcm), China (16%, +3.6 bcm), and Taiwan (15%, +0.9 bcm), whereas EU LNG imports fell by 9% (-1.8 bcm), along with that in India (by 13%, -1.2 bcm) and in Japan (by 3%, -0.7 bcm). 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.

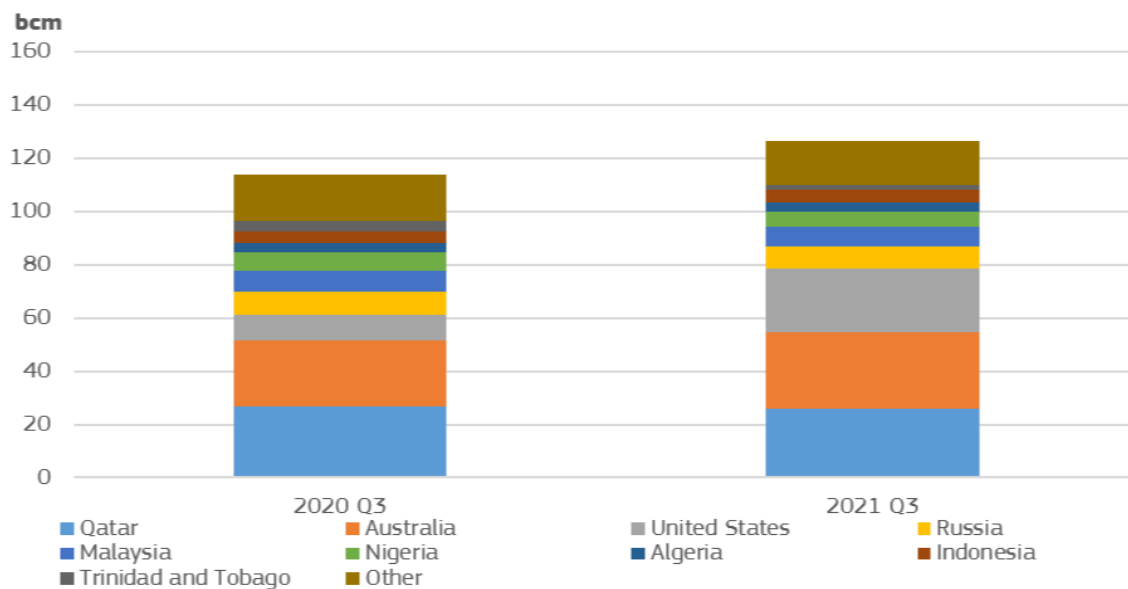
Figure 28 – LNG imports in the main consumer markets in the third quarters of 2020 and 2021



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, in Q3 2021 Australia became the biggest LNG exporter in the world, ensuring 29 bcm of the estimated global LNG supply. Qatar came to the second place, exporting 26 bcm LNG in Q3 2021. The United States were the third most important exporter, supplying 24 bcm of LNG, followed by Russia (8 bcm), Malaysia (7 bcm), Nigeria (6 bcm), Indonesia (5 bcm), Algeria (3 bcm) and Trinidad and Tobago (2 bcm). In year-year comparison, LNG exports from the United States went up by 151% (14.5 bcm), largely owing to low exports in Q3 2020, characterised by massive cargo cancellations at the height of demand destruction in 2020. LNG exports from Australia rose by 14% (3.6 bcm), while exports were Qatar, Russia and Algeria decreased measurably (by 3% to 11%).

Figure 29 – LNG exports in the main consumer markets in the third quarters of 2020 and 2021



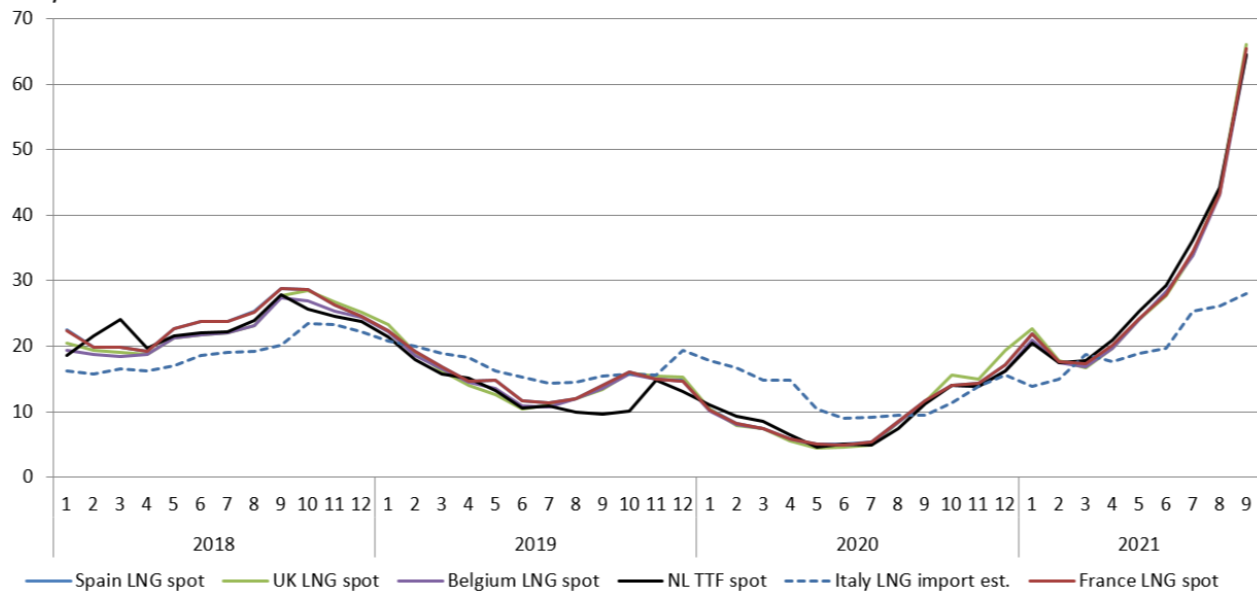
Source: Refinitiv tracking of LNG vessels. Export data are based on cargo departure dates, therefore total amount of global exports might differ from global import numbers

2.3 European gas markets

2.3.1 LNG contracts in Europe

- Figure 30 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 third quarter of 2021, hub prices and hub-based import price contracts in western-Europe showed a significant upturn amid general gas wholesale gas price increases. Looking merely the hub based contracts, they remained relatively well converged, and differentials in September 2021 amounted to 1.5€/MWh. However, if we taking into account the Italian COMEXT derived average price, the difference was more than 35 €/MWh, implying that LNG import contracts in Italy are either not fully linked to spot prices or there is a time lag impact (oil indexation or link to forward gas price contract), which will be only observable in the following period. The Q3 2021 quarterly average hub-based prices practically doubled compared to the previous quarter, reflecting the continued price upturn on wholesale gas markets and import contracts. In year-on-year comparison, most contracts showed more than fivefold increases. The estimated price increase for LNG import contracts in Italy showed an upturn of 42% quarter-on-quarter, while year-on-year it went up by 180%. If compared to the pre-Covid lockdown period, Q3 2019, hub-based prices showed a three-to-fourfold increases, implying that current prices are significantly higher even compared to 'normal' times.

Figure 30 - Price developments of LNG imports in the UK, Belgium, Spain and Italy, compared to the TTF benchmark
Euro/MWh

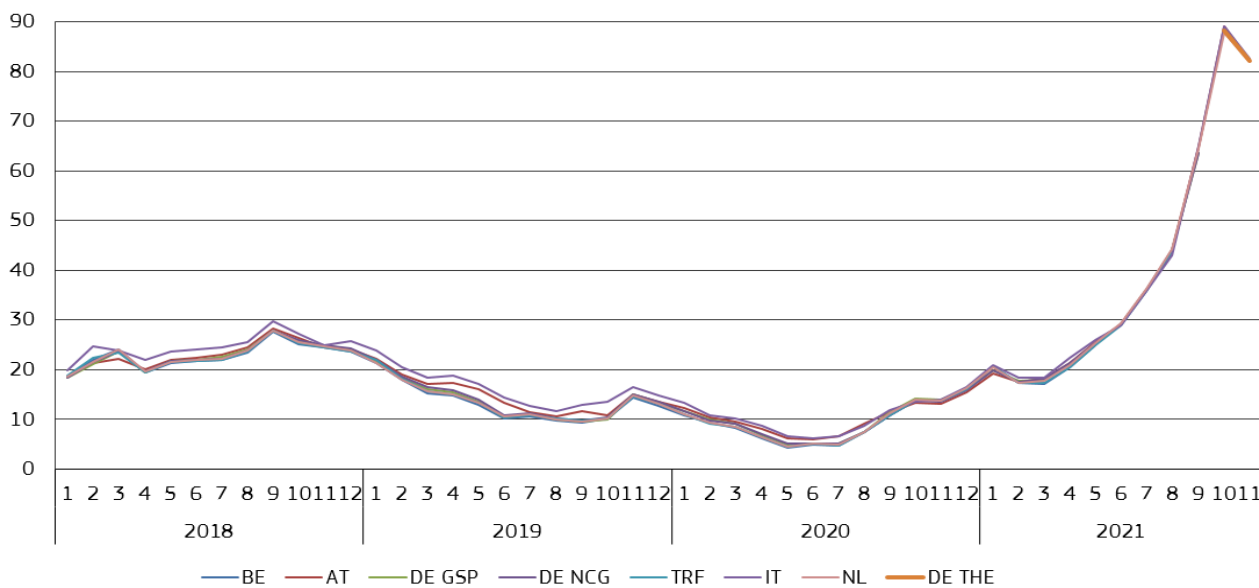


Note: Landed prices for LNG. Source: S&P Global Platts, Refinitiv, European Commission estimates based on Eurostat COMEXT data, retrieved on 10 December 2021.

2.3.2 Wholesale price developments in the EU

- European hub prices were in a narrow range, averaging around 47.3–48.4 €/MWh in the third quarter of 2021, measurably higher than in the previous quarter, Q2 2021 (24.7–25.8 €/MWh), adding around 85–95% to the price level just within a quarter's time, which shows a significant upturn in prices. Hub prices in year-on-year comparison rose to six times as high, compared to the price range in Q3 2020 (7.7–9 €/MWh). The average TTF hub price was 48.4 €/MWh in Q3 2021, significantly up to 7.8€/MWh measured in Q3 2020. Comparing to Q3 2019, the observed prices were up by 280–350%, signalling that current prices are also measurably higher than two years before.
- In the third quarter of 2021, gas markets in Asia retained their premiums to Europe, limiting LNG send-outs. On the top of this, underground storage filling rates showed a significant gap (around 15% compared to the average of the preceding years), which increased supply tightness of the gas market. During Q3 2021 inflow of Russian gas was much less than expected, and in September maintenance works on Norwegian infrastructure put an obstacle in the way of quick storage refilling. News around the permission process of the new Nord Stream 2 pipeline also added to market volatility. At the same time renewable power generation was lower, which prompted higher use of gas in electricity generation. These factors all contributed to the significant wholesale gas price increase in Q3 2021 on the European markets.

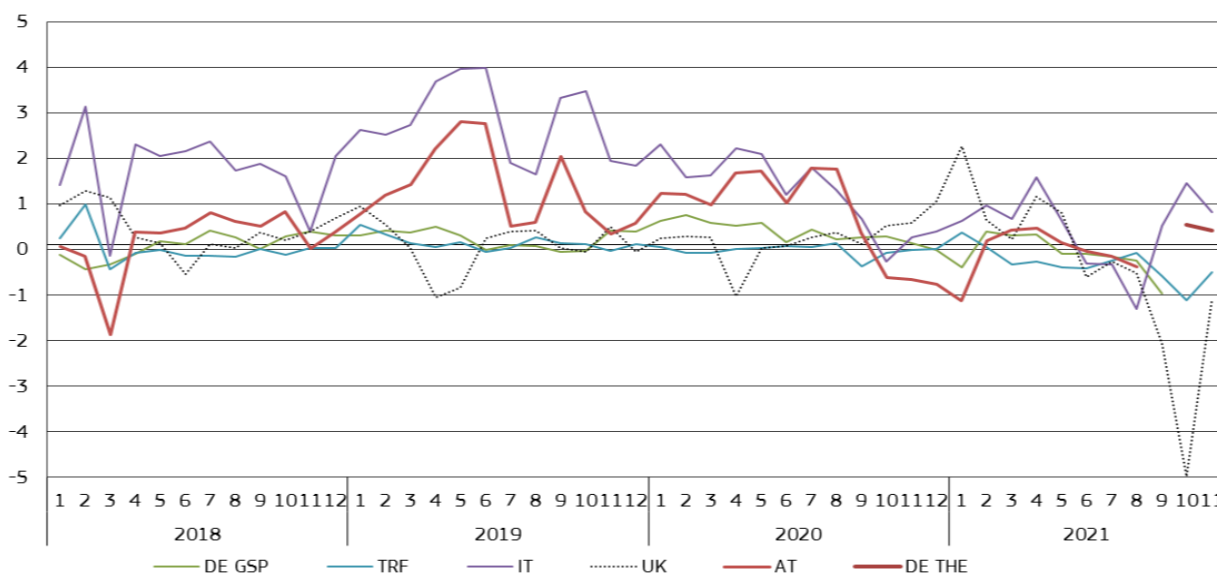
Figure 31 - Wholesale day-ahead gas prices on gas hubs in the EU
Euro/MWh



Source: S&P Global Platts

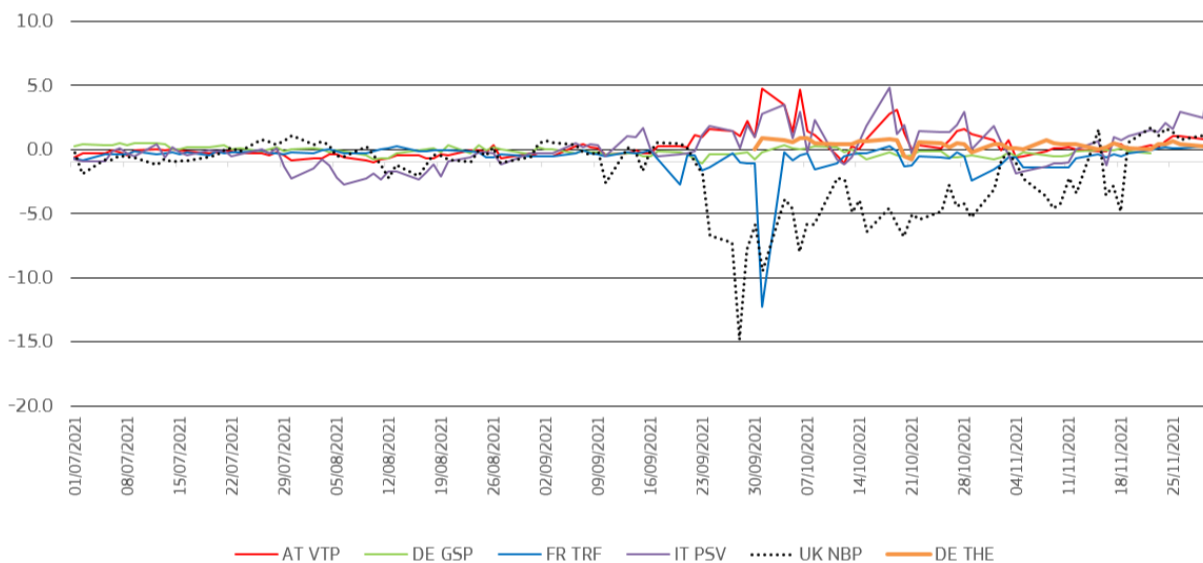
- As Figure 32 and Figure 33 show, the French TRF market was in a slight discount to TTF market during most of the time in the third quarter of 2021, which might have been related to better gas storage filling rates compared to other European markets, in consequence of the compulsory filling rate of 85% by early November. At the end of September as flows from Norway recovered, a temporary price drop resulted in widening price discount to the TTF hub.
- The German Gaspool also remained well-aligned with the TTF in Q3 2021, in spite of low storage fullness, lower than expected inflows from Russia and low wind power generation availability in many periods during the quarter. On 1 October 2021, the Gaspool and NGC markets were merged, and the new THE market showed a slight premium to TTF in October and November 2021.
- The Austrian hub showed a slight discount to the TTF in July and August 2021, which turned to premium in September 2021. Going forward in the quarter, the low storage filling rates weighed more and more on Austrian wholesale gas prices. Gazprom also operates storages in the country, which dragged down the filling rates. In October, with higher European hub prices, the Austrian premium also increased.
- In Italy, the PSV hub price had a measurable discount vis-à-vis TTF during August 2021 (1.4 €/MWh), as high storage filling rates (compulsory filling milestones for the beginning of each month during the filling season) in European comparison, abundant imports via the TAP pipeline and good LNG send-out ensured a well-supplied market. In September, in parallel with high prices in Europe, this discount vanished and turned to a premium, also owing to decreasing LNG send-out.
- In July and August 2021, the NBP hub price was during most of the time slightly below the TTF benchmark, even if the same factors, such as low LNG berthing, low gas storage levels, uncertainty over Russian inflows, less than expected wind power generation and outages on Norwegian infrastructure propelled NBP hub prices higher. At the end of September, as inflows rose from Norway, prices plunged. In October, milder and windier weather also contributed to the discount to continental markets.

Figure 32 - 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

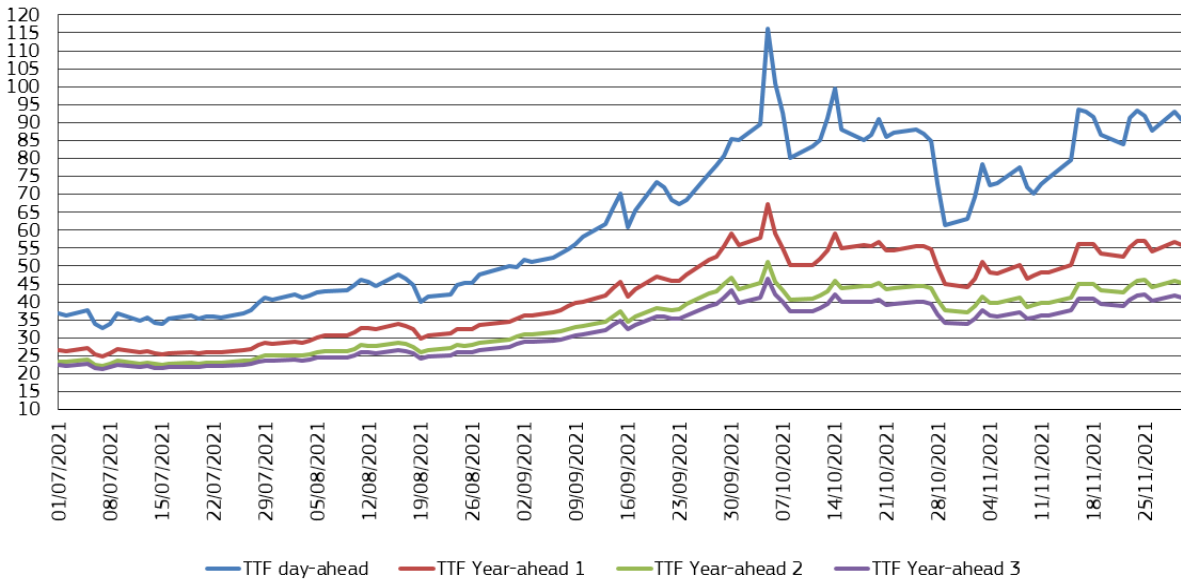
Figure 33 - Premium of daily average wholesale day-ahead gas prices at selected hubs compared to TTF Euro/MWh



Source: S&P Global Platts, European Commission computations

- Figure 34 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 continued to rise rapidly in Q3 2021, starting the quarter at 37 €/MWh and finishing at 85 €/MWh. In early October, spot prices rose even further, above 116 €/MWh, and late November they were still around 90 €/MWh. However, the steep increase in the spot contract was only partially mirrored by forward contracts. On 1 July, the year-ahead, two-year ahead and three year-ahead contracts were respectively 26.5 €/MWh, 23.4 €/MWh and 22.4 €/MWh, whereas on 30 September these three contracts reached 59 €/MWh, 46.7 €/MWh and 43.1 €/MWh. The discount of the year-ahead contract to the spot (market in backwardation) grew from 10.2 €/MWh to 26.3 €/MWh during Q3 2021, and by the end of November 2021 this difference rose to 35 €/MWh, implying that the market, though forward prices are also rising, anticipates a correction of the current price level.

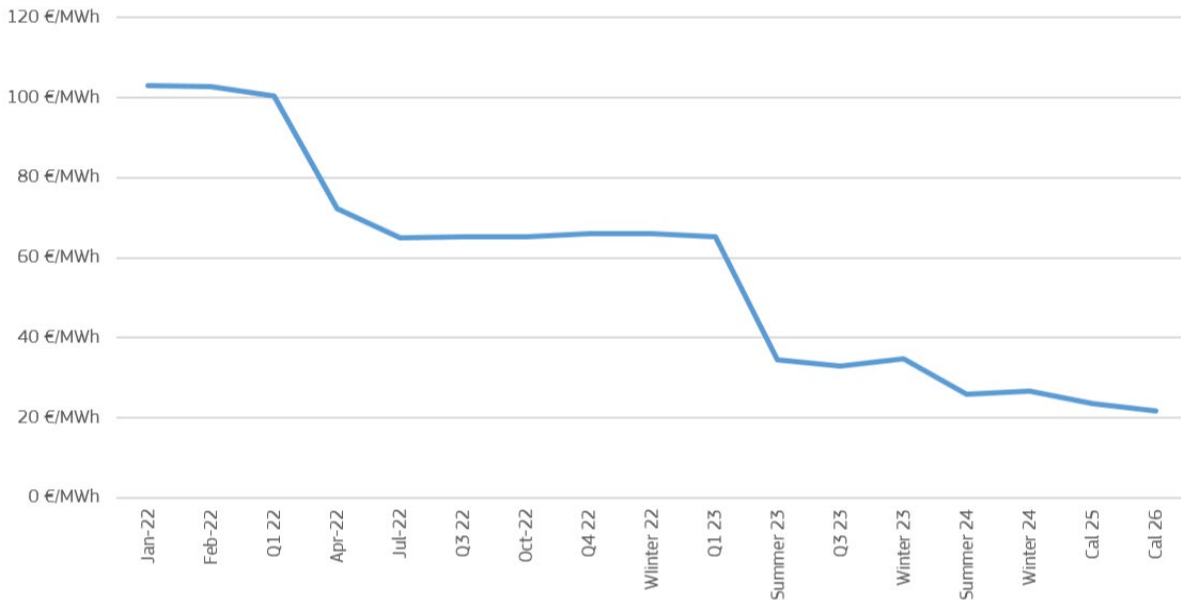
Figure 34 - Forward gas prices on the TTF hub
Euro/MWh



Source: S&P Global Platts

However, as the next chart shows, the decade-long typical values (in the range of 15-25 €/MWh) of spot prices are not likely to return in the next two-three years, or at least this is what we can assume looking at the forward price curve of the TTF hub in early December 2021. It is worth to recall that the prediction force of forward curves under the current volatile price environment cannot be taken as granted, and factors like storage levels at the end of the next heating season and weather circumstances in 2022 can easily significantly change the current market expectations.

Figure 35 - Forward price curve on the TTF wholesale gas market - 8 December 2021

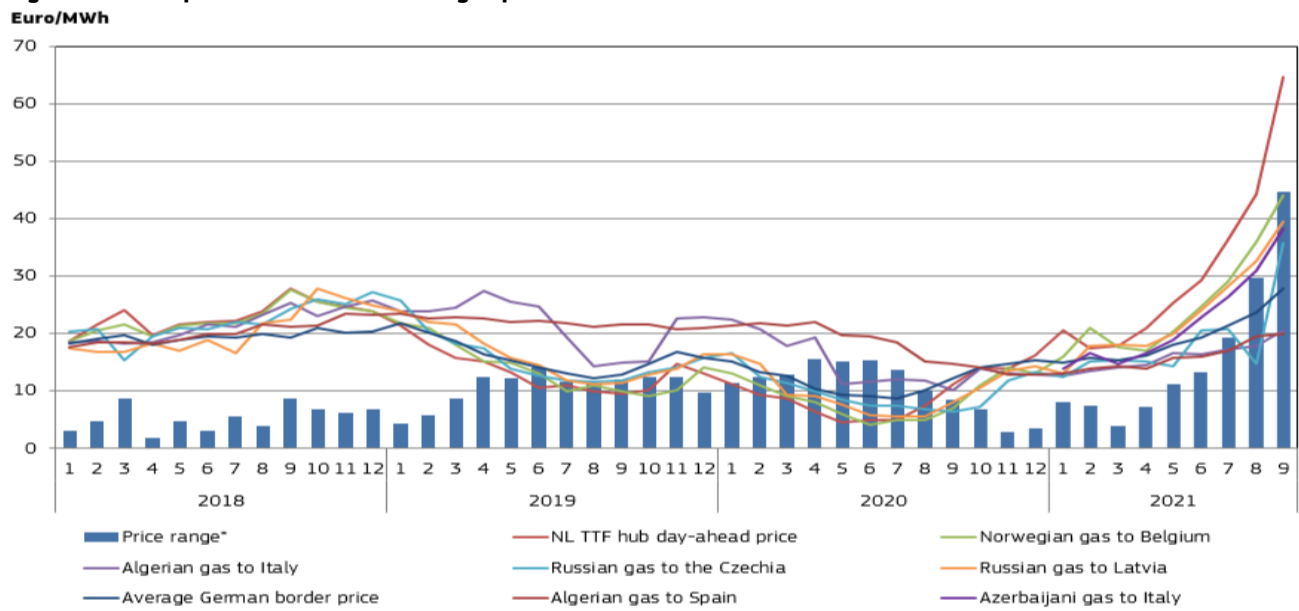


Source: TTF

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

- Figure 36 compares a selection of estimated border prices of pipeline 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 third quarter of 2021, the estimated Algerian pipeline import price in Spain was 18.8 €/MWh, up by 23% compared to the previous quarter (15.2 €/MWh), and by 16% compared to Q3 2020. The Algerian contract clearly reflects the time-lagged impact of recovering crude oil prices as of mid-2020. In Q3 2021, the average estimated Algerian import price in Spain had an unprecedentedly large discount of almost 29 €/MWh to the Spanish LNG import price, providing a competitive advantage to Algerian imports, increasing by 63% Q3 2021 year-on-year in Spain.
- In the third quarter of 2021 Algerian gas import price in Italy (18.5 €/MWh) was similar to that in Spain. In quarter-on-quarter comparison, Algerian import price in Italy was up by 17%, and year-on-year it rose by 63% in Q3 2021. Pipeline gas imports from Algeria was up by 35% in Q3 2021 year-on-year in Italy (See Chapter 1.3 Imports). For the future, the current advantage of oil-indexed contracts is likely to remain 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 showed an accelerating increase in Q3 2021 and were respectively up by 23% and 43% compared to the previous quarter, whereas year-on-year they rose by 246% and 421%. 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 (23.7 €/MWh vs. 33.4 €/MWh) in Q3 2021.
- Prices of European gas contracts showed signs of divergence in Q3 2021, as the difference between the cheapest and most expensive contract rose from 13.3 €/MWh in June to 44.7 €/MWh in September 2021. In Q3 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. However, even without TTF, price differential would have risen from 9 €/MWh to 24 €/MWh between June and September 2021, implying that high price levels usually magnify differences between differently priced gas import contracts.
- Hub-based contracts and hub prices themselves continued their upturn in the third 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 36 - Comparison of EU wholesale gas price estimations



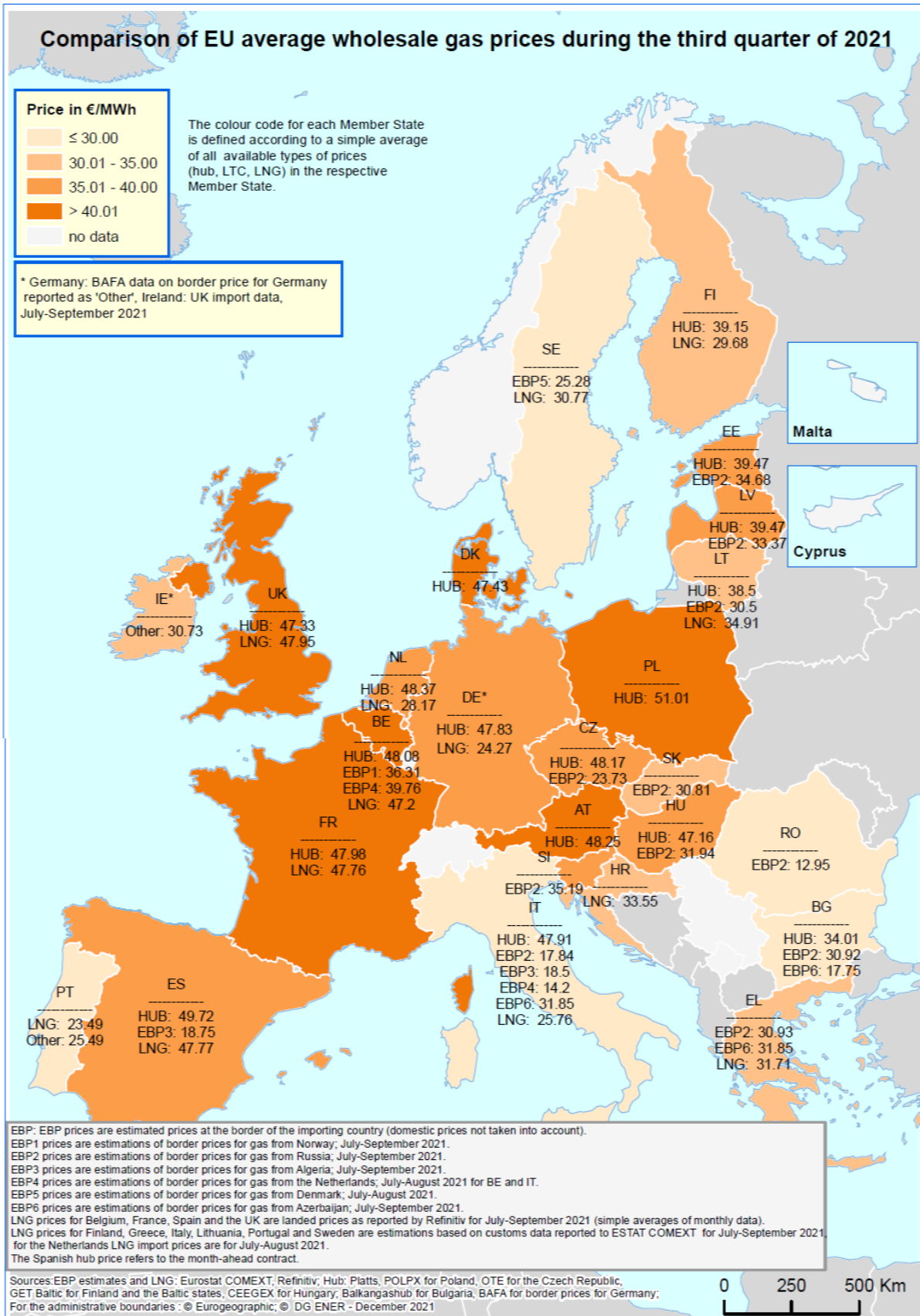
Source: Eurostat COMEXT and European Commission estimations, BAFA, S&P Global Platts

*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 third quarter of 2021.

Map 1 - Comparison of EU wholesale gas prices in the third 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.

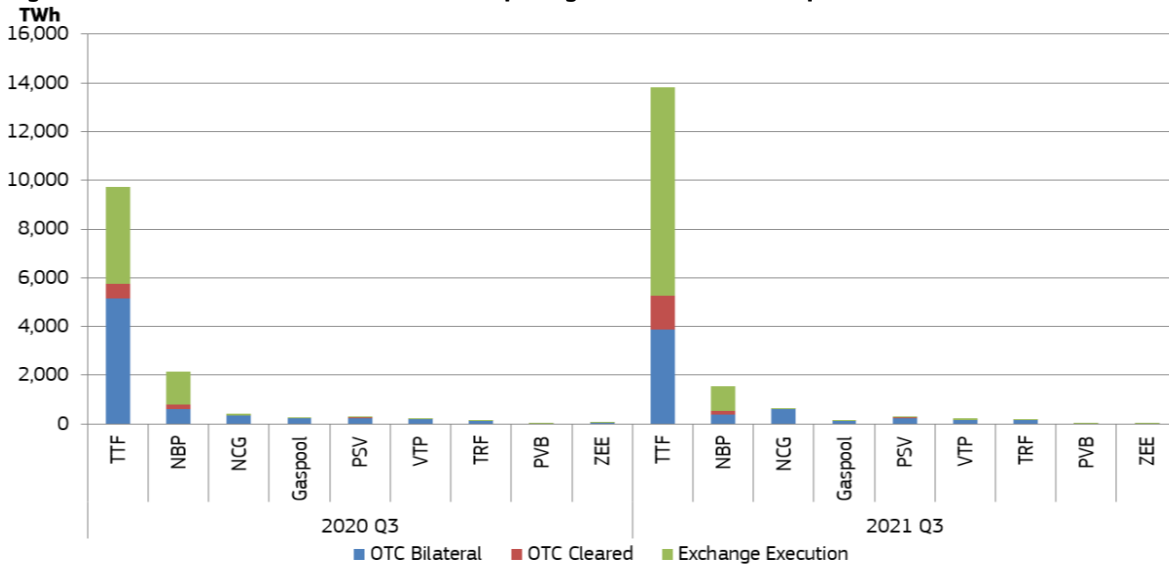
2.3.4. Gas trade on the EU hubs

- As Figure 37 shows, liquidity increased on the main European gas hubs in the third quarter of 2021 by 27% year-on-year, after decreases of 4% year-on-year in Q2 2021 and of 13% in Q1 2021. In Q3 2021, the total traded volume amounted to around 16 899 TWh (equivalent to around 1 568 bcm and in monetary terms representing €817 billion³²). The Q3 2021 traded volume was around 22 times more than the gas consumption in the seven Member States³³ covered by the analysis in July-September 2021. Comparing to the EU as a whole, traded volume in Q2 2021 represents 20 times the total EU-27 gas consumption in this period.
- The year-on-year change in traded volumes in Q3 2021 showed mixed picture among the observed trading hubs in Europe. Volumes on the largest and most liquid TTF hub rose by 42% year-on-year. Looking at the two German hubs, NGC and Gaspool together (this was the last quarter with separate German hubs, as on 1 October they were merged to create the THE hub), traded volumes were up by 40% year-on-year. At the same time, traded volumes on the French TRF were up by 21%, on the Spanish PVB by 12% and on the Italian PSV by 5%. In contrast, traded volumes on the VTP hub in Austria were slightly down by 2%, whereas on the Belgian Zeebrugge the steep fall in volumes continued in Q3 2021, amounting to 55% year-on-year. 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 29% compared to Q3 2020.
- As the year-on-year change in traded volumes on the TTF hub rose by 42% in Q3 2021, while traded volumes on overall observed European markets increased slower, only by 27%, the share of TTF in the total European gas trade kept on increasing in Q3 2021 and amounted to 82%, whereas a year before it was only 73%. If looking at only the EU countries, its share was even bigger, 90%. 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. The next quarters will show how the new merged German market (THE) will evolve, having a similar central location and good connections with storages and multiple suppliers. On the other hand, decrease on the NBP hub signalled a further shift from once Europe's most liquid market. The NBP traded volume in Q3 2021 fell by 29% compared to the same period of 2020, and the share of NBP in Q3 2021 fell to 9% in the total European observed trade, down from 16% in Q3 2020.
- Other markets had lower shares: Germany (NGC and Gaspool together) had a share of 5.4%, while the Italian PSV had a lower share, 1.7%, followed by VTP (1.4%), TRF (1.3%), PVB (1.2%), and Zeebrugge had only a minor share in the European gas trade (0.1%) in Q3 2021.
- Net gas import of gas was up by 5%, however, LNG imports fell by 9% year-on-year in the EU in Q3 2021, and consumption of gas went down by more than 10%. Even with decreasing consumption and slightly increasing imports, traded volumes were up on the most liquid European hubs. This was mainly due to the increase in exchange-executed contracts, whereas OTC contracts fell again year-on-year in Q3 2021. Shifting trade from the OTC market to exchange-executed contracts was helped by rapidly increasing prices as the number of traders being able to effectively trade decreased, owing to elevated default risks for smaller traders on the OTC market. Exchange-executed trade is close by in term, helping smaller traders to engage in this market, in contrast to the OTC, where collaterals nowadays cover a decreasing number of contract and margin calls might be invoked for insurance reasons, also pushing out smaller participants from the OTC market.
- The share of exchange executed contracts on the Dutch TTF hub was 62% in Q3 2021, which was the highest among the observed EU countries, and was up by a staggering 21 percentage points compared to Q3 2020. On the Spanish PVB the share of exchange executed contract amounted to 59%, up by 27 percentage points. On the French TRF the share of exchange executed contracts reached 22% in Q3 2021 (up by 3 percentage points). On the VTP hub in Austria this share was also 22%, up from 15% in the same period of 2020, while on the two German hubs together it amounted to 15% (up by 1 percentage point). On Zeebrugge, the share of exchange-executed contracts was much lower, only 9%, whereas it was the lowest on the Italian PSV, amounting to barely 2% in Q3 2021. On the NBP hub in the UK, the share of exchange trade was still the highest among all observed markets, amounting to 65% in Q3 2021, even up by 2 percentage points compared to Q3 2020.

³² Assuming that all trade was carried out on the quarterly average spot price of the TTF hub. As spot prices significantly rose in Q3 2021 and developed a considerable premium over forward contracts, this amount might overestimate the monetised traded value

³³ Netherlands, Germany, France, Italy, Belgium, Austria and Spain. 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.

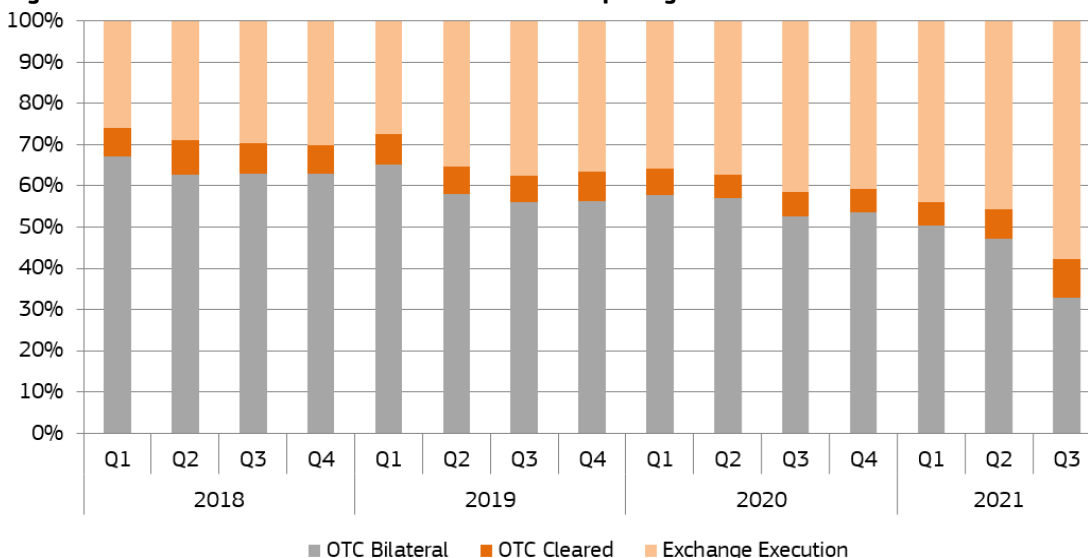
Figure 37 - Traded volumes on the main European gas hubs in the third quarters of 2020 and 2021



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); Spain: PVB (Virtual Balancing Point); 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 Q3 2021 33% of the total trade was OTC bilateral, 9% was OTC cleared, whereas the share of exchange-executed contracts reached 58%. The share of exchange-executed contracts increased by 16 percentage points year-on-year in Q3 2021, whereas the share of OTC bilateral fell by 19 percentage points, and that of OTC cleared went up by 3 percentage points. The share of exchange executed volumes (58%) was the highest in the last six years, and for the first time ensured more than the half of the total trade, reinforcing the trend of shift towards exchanges from the OTC market.
- Amid the general rise in traded volumes (27% in Q3 2021 year-on-year), exchange executed volumes managed increase measurably, by growing 77% year-on-year on the observed European markets. In the same period, the total OTC traded volume (bilateral and cleared together) fell by 8%. This underlines the increasing importance of exchange-executed contracts in the gas trade on the major European hubs.

Figure 38 - Share of traded volumes on the main European gas hubs



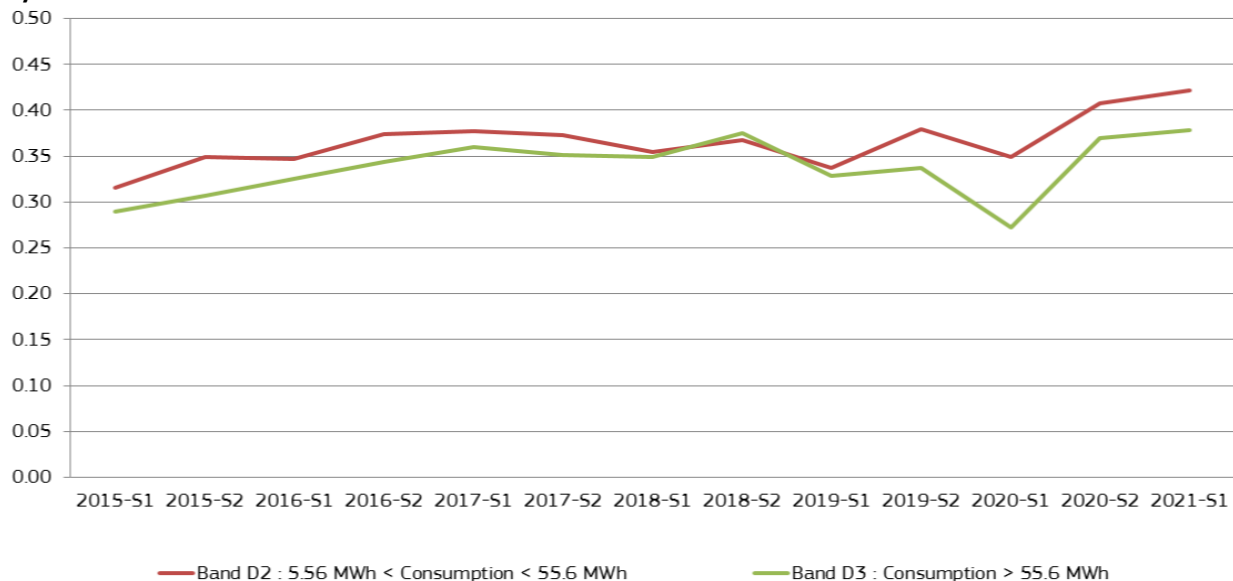
The chart covers the following trading hubs: Netherlands: TTF (Title Transfer Facility); Germany: NCG (NetConnect Germany) and Gaspool; France: PEG (Point d'Echange Gaz); Italy: PSV (Punto di Scambio Virtuale); Spain: PVB (Virtual Balancing Point); Belgium: Zeebrugge beach, Austria: Virtual Trading Point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

3. Retail gas markets in the EU and outside Europe

3.1 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 first half of 2021) and Harmonised Consumer Price Indices (HICP) for both the household prices and industrial consumers.
- For household consumers, the estimated average retail price in Q3 2021 in the EU (including all taxes) practically did not show change in year-on-year comparison, however, compared to the previous quarter, Q2 2021, the average price went up by 6.8%. In the most typical consumption Band, D2, in the third quarter of 2021 the estimated average price (including all taxes) was 6.9 Eurocents/kWh, up from 6.4 Eurocents/kWh in Q2 2021, and up from 6.3 Eurocents/kWh in Q1 2021. (See the estimated household prices on Map 2). It is important to recall that substantial retail gas price increases largely occurred in the fourth quarter of 2021, implying that Q3 2021 did not show yet these important changes.
- In the third 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 (3.1 Eurocent/kWh), Hungary (3.2 Eurocent/kWh), Romania (3.3 Eurocent/kWh) and Lithuania (3.6 Eurocent/kWh) and whereas the highest prices could be measured in Sweden (12.3 Eurocent/kWh), Denmark (10.8 Eurocents/kWh), Netherlands (9.6 Eurocent/kWh), Italy (8.1 Eurocent/kWh) and France (7.8 Eurocent/kWh). The price differential ratio between the cheapest and the most expensive Member State decreased slightly, to 3.9 (in the previous quarter it was 4.4), however, compared with Q3 2020 the price convergence did not improve across the EU. As the next chart (Figure 39) shows, bi-annual price dispersion, as measured by the relative standard deviation of retail gas prices in consumption bands D2 and D3, remained at the same level (or even increased, showing divergence of prices across the EU) between the second half of 2020 and the first half of 2021.

Figure 39 - Bi-annual retail gas price dispersion for household customers across the EU Member States, as measured by relative standard deviation

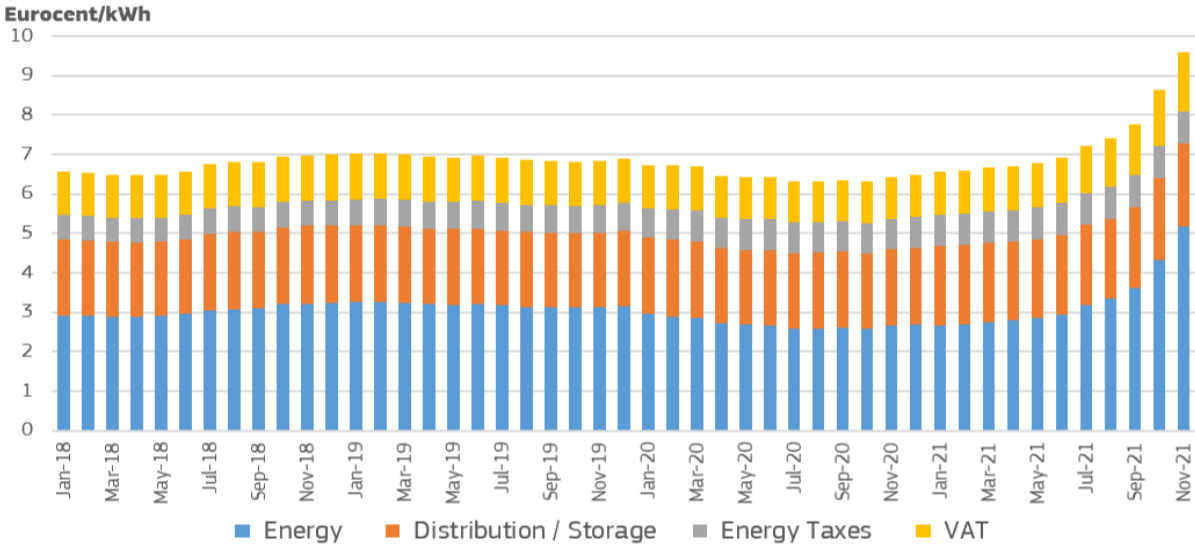


Source: Computation based on Eurostat data

- Figure 40 and Figure 41 show the monthly evolution of the EU average residential end-user retail gas prices over the last few years, the breakdown of prices paid by typical households in the European capitals in November 2021, and the change in percentages compared to November 2020. Over the recent period, as higher wholesale gas prices started to filter in the retail contracts, the share of the energy component showed a significant increase. On average, 54% of the retail price could be assigned to the energy component in November 2021, while the rest covered distribution/storage costs (22%), energy taxes (8%) and VAT (16%). Back in August 2021, the share of the energy component was only 45%, rising to 47% in September, and to 50% in October. In November 2021, retail gas prices in EU capitals shows an estimated increase of 49%, year-on-year.
- There were significant differences in November 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 34% (Stockholm) and 41% (Paris and Ljubljana) to Bucharest (76%) and Prague (83%). The share of distribution/storage costs ranged from 8% (Amsterdam and Bucharest) to 41% (Bratislava) and 34% (Paris). The share of energy taxes ranged from 2% (Athens and Brussels) and 3% (Madrid) to 25% (Amsterdam) and 19%

(Copenhagen). 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.

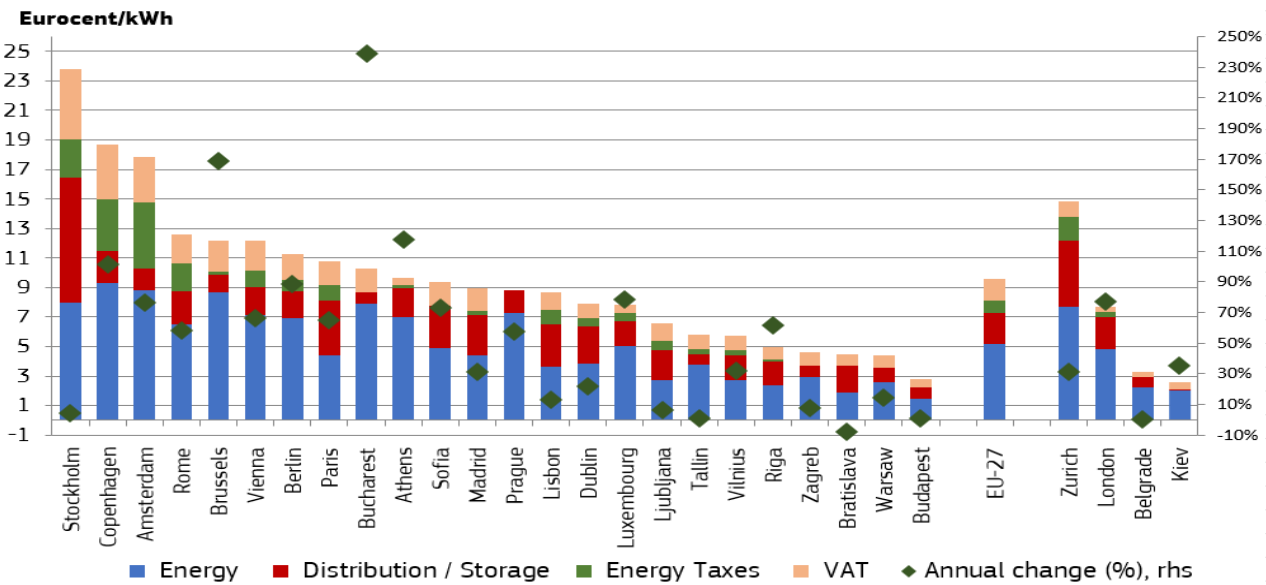
Figure 40 – Monthly average gas price in the EU, paid by typical household customers



Source: VaasaETT

- Figure 41 also shows that even the energy component is very variable in absolute terms: in November 2021, it was 6.3 times higher in Copenhagen than in Budapest. There were also considerable differences across the Member States in the relative share of network costs and taxes. The ratio of highest and lowest network components across the EU was 12.7 (between Tallinn and Stockholm). The highest-lowest tax component ratio (taking energy taxes and VAT together), not counting Prague where VAT rates has been temporarily reduced to 0, was 12.6 (Budapest and Amsterdam) in the same period.
- With the exception of one capital city out of the observed 24, prices were higher in November 2021, compared to the same month of the previous year. Prices decreased only in Bratislava (7%), interestingly driven by the decrease in energy costs. Prices went up by the most in Bucharest (239%), Brussels (169%), Athens (118%), and Copenhagen (102%), practically driven by the increase of energy costs, whereas in some cases network costs or energy taxes slightly decreased. It seems that recent price increases on wholesale gas markets are already measurable in the final retail household prices in most of the EU capital cities. In November 2021, Budapest remained the cheapest capital in the EU in terms of gas prices for household consumers, followed by Warsaw and Bratislava, whereas Stockholm, Copenhagen and Amsterdam and were the three most expensive capital cities.

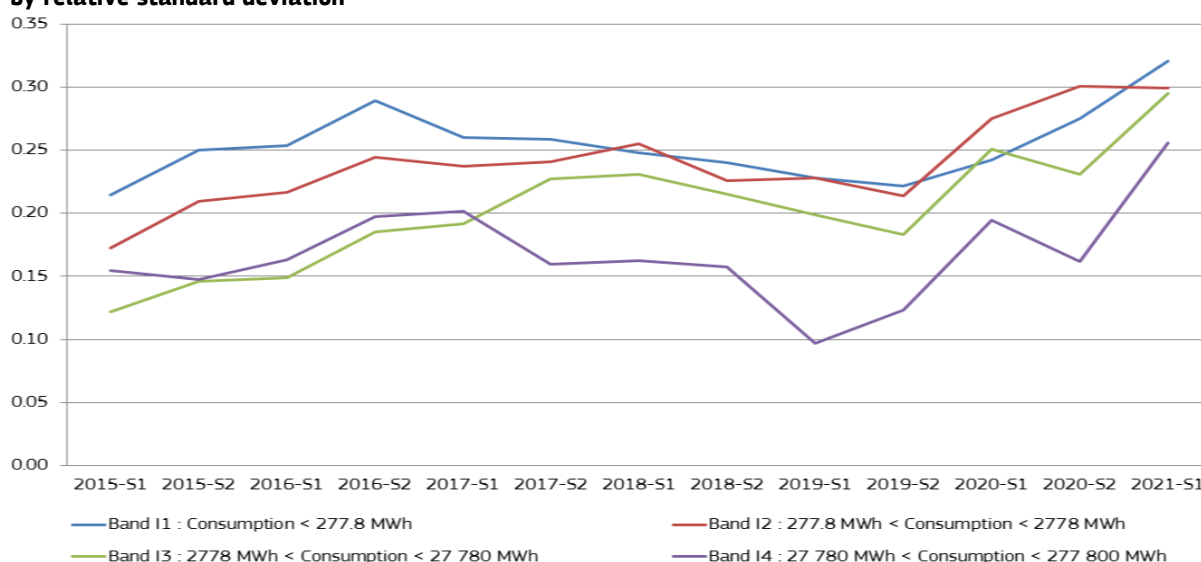
Figure 41 - Breakdown of gas price paid by typical household customers in European capitals and annual change in prices, November 2021



Source: VaasaETT

- Retail gas prices for industrial customers rose measurably by 24.4% in Q3 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 2.45 Eurocent/kWh, up by 6.8% compared to Q2 2021 Eurocent/kWh. (See the estimated industrial prices on Map 3.) There was only one country (Slovakia) in the EU where industrial gas prices decreased in year-on-year comparison in Q3 2021, while in the other 23 observed countries (data were not available for Cyprus, Finland and Malta) increases could be observed. It seems that price hikes on wholesale gas markets started to filter in the retail prices for industrial customers in Q3 2021, having an average consumption. Price increases could also be observed for industrial customers having larger annual gas consumption (in both Band I5 and Band I6 bands increases of 40-50% could be observed in Q3 2021 year-on-year). Significant price increases for energy intensive industries meant bigger production costs, leading to decrease in production and/or increases in the final product prices.
- It must be noted that these computed quarterly prices are based on Eurostat data (referring to the first half of 2021), corrected by HICP figures, implying that by the time the next half-yearly price data will be available, numbers might show different trends.
- In the third quarter of 2021, the lowest estimated industrial price in consumption Band I4 could be observed in Latvia (2.0 Eurocent/kWh), Romania (2.1 Eurocent/kWh) and Portugal (2.2 Eurocent/kWh). The highest prices could be observed in Sweden (4.1 Eurocent/kWh), Denmark (3.5 Eurocent/kWh) and Estonia (3.3 Eurocent/kWh). In Q3 2021, the price ratio of the cheapest and the most expensive country in the EU was 2.0. As Figure 42 shows, price differentials across different EU countries slightly rose between the second half of 2020 and the first half of 2021.

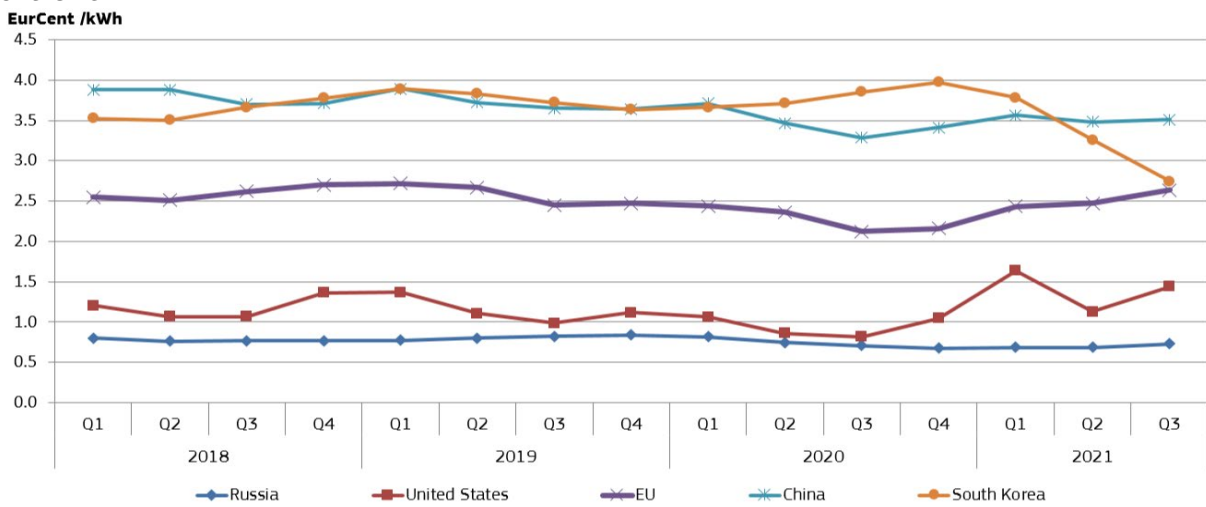
Figure 42 - Bi-annual retail gas price dispersion for industrial customers across the EU Member States, as measured by relative standard deviation



Source: Computation based on Eurostat data

- Figure 43 shows the evolution of industrial retail gas prices in the EU, compared with some important trade partners of the European economy. In the third quarter of 2021, retail gas prices for industrial customers in China had a measurable premium to the EU average (as they were 33% higher), whereas in Korea natural gas was only 4% more expensive than the EU average. On the other hand, retail gas prices in the United States were 45% lower than in the EU and gas prices in Russia had a discount of almost 72% to the EU average. Compared to Q3 2020, the biggest increase in industrial gas retail prices could be observed in the United States (76%). Prices were slightly up in China (7%) and in Russia (3%), whereas they fell in Korea (29%). In the EU retail industrial prices were up by more than 24%.

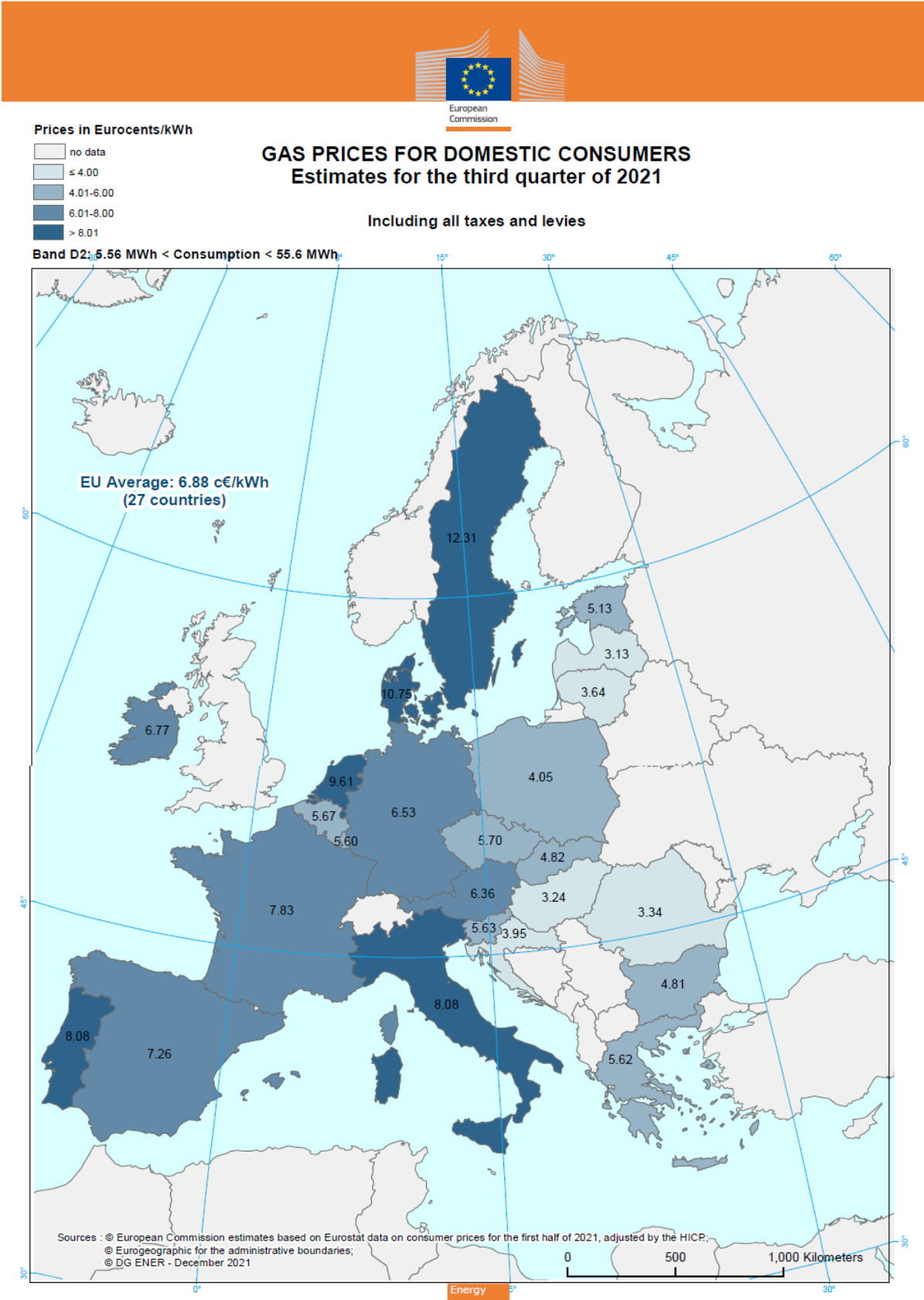
Figure 43 - The EU average industrial retail gas price in comparison with the prices of some important trade partners of the EU



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 third quarter of 2021.

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



Source: Eurostat

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



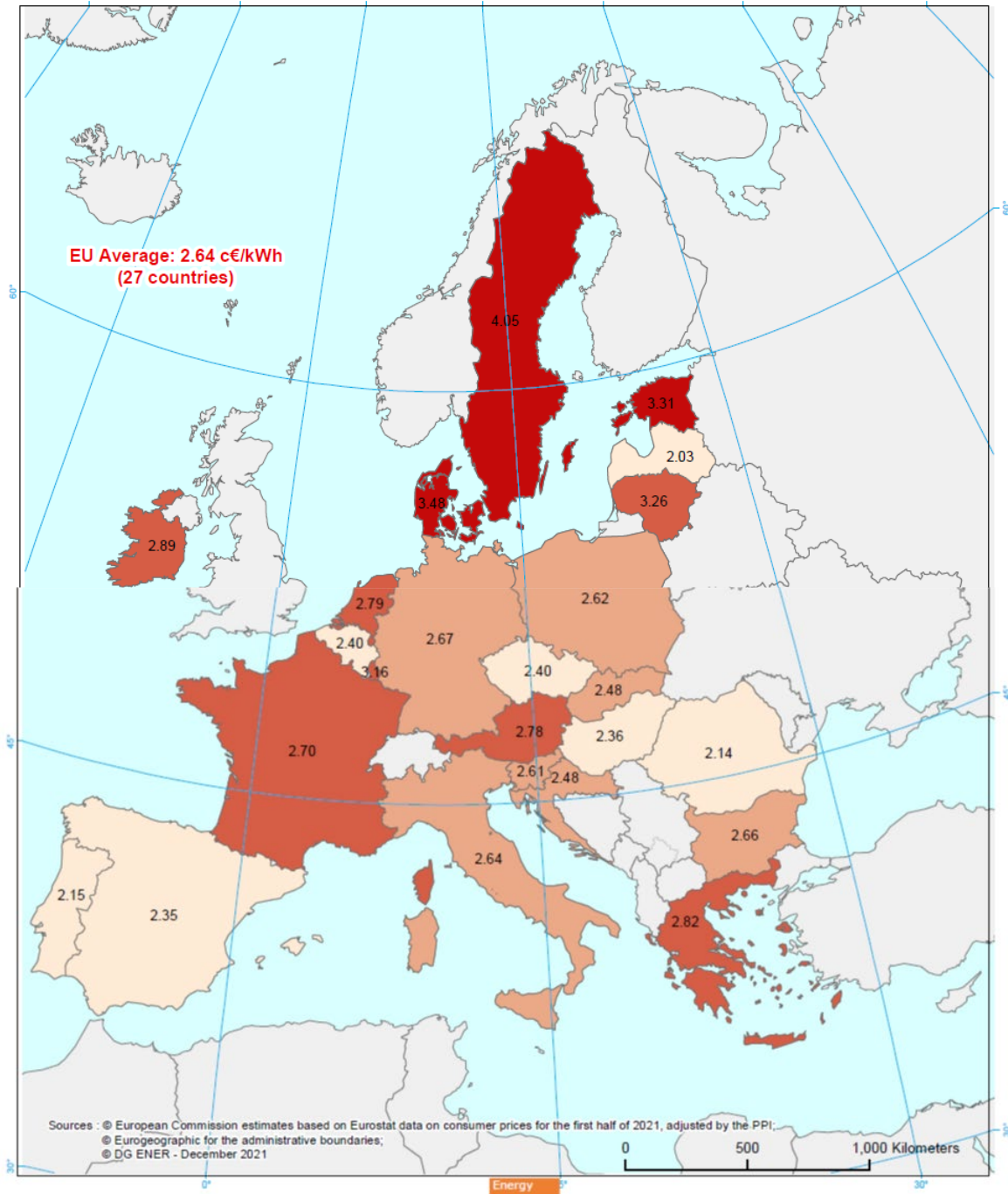
Prices in Eurocents/KWh

- no data
- ≤ 2.40
- 2.41 - 2.70
- 2.71 - 3.30
- > 3.31

GAS PRICES FOR INDUSTRIAL CONSUMERS
Estimates for the third quarter of 2021

Excluding VAT (value added tax) and other recoverable taxes

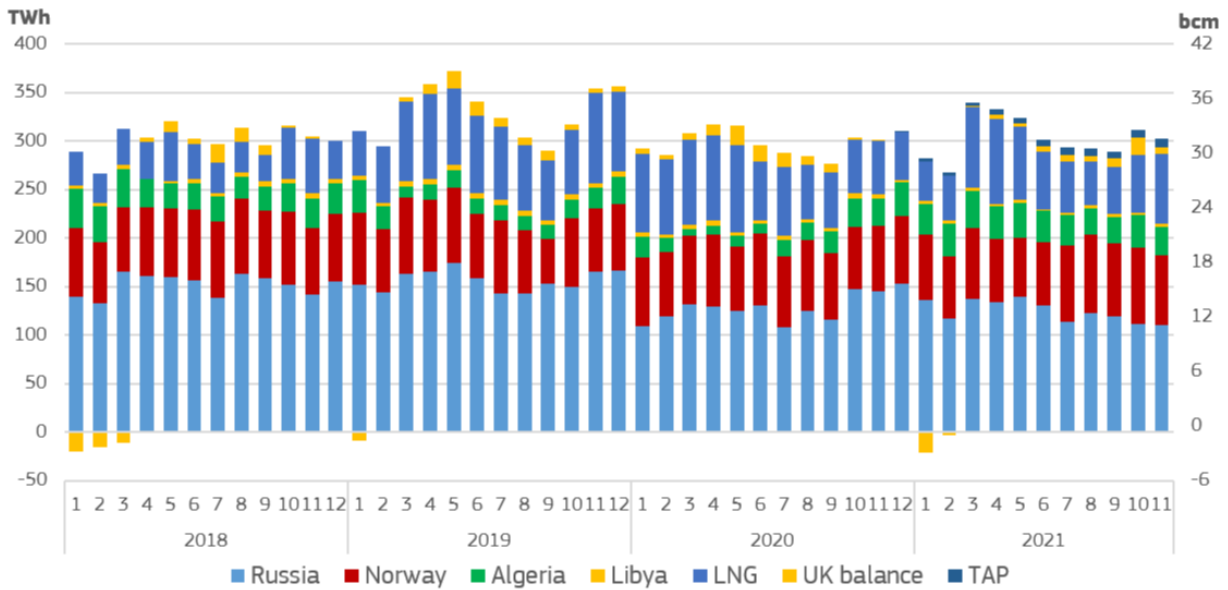
Band 14: 27 780 MWh < Consumption < 277 800 MWh



Source: Eurostat

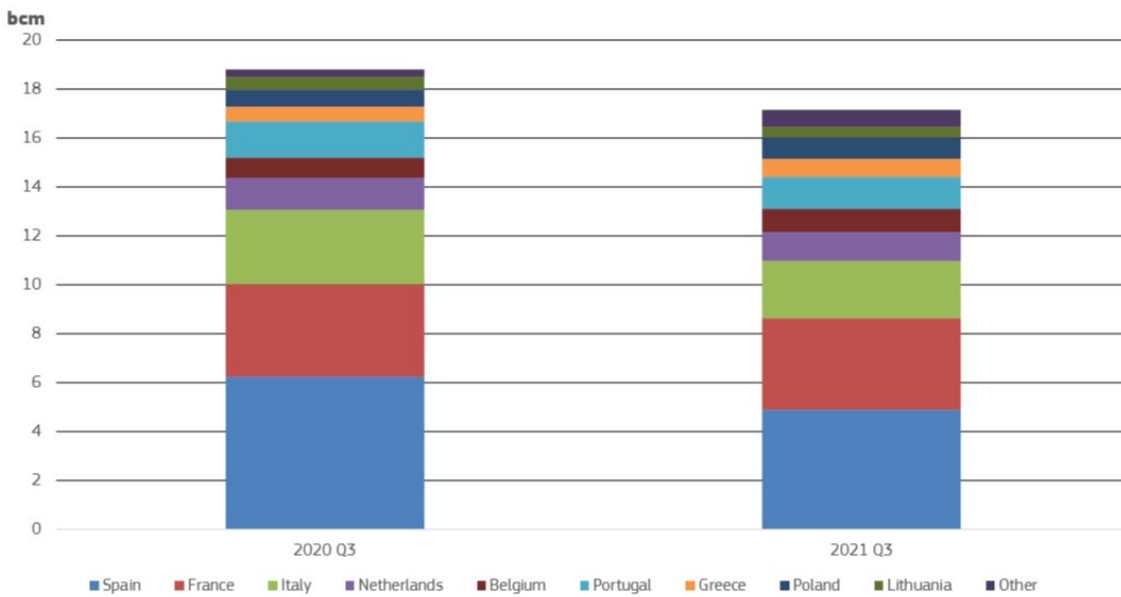
4. Appendix – charts providing further details on market developments³⁴

Figure 44 – Monthly evolution of gas imports from extra-EU sources



Source: ENTSO-G

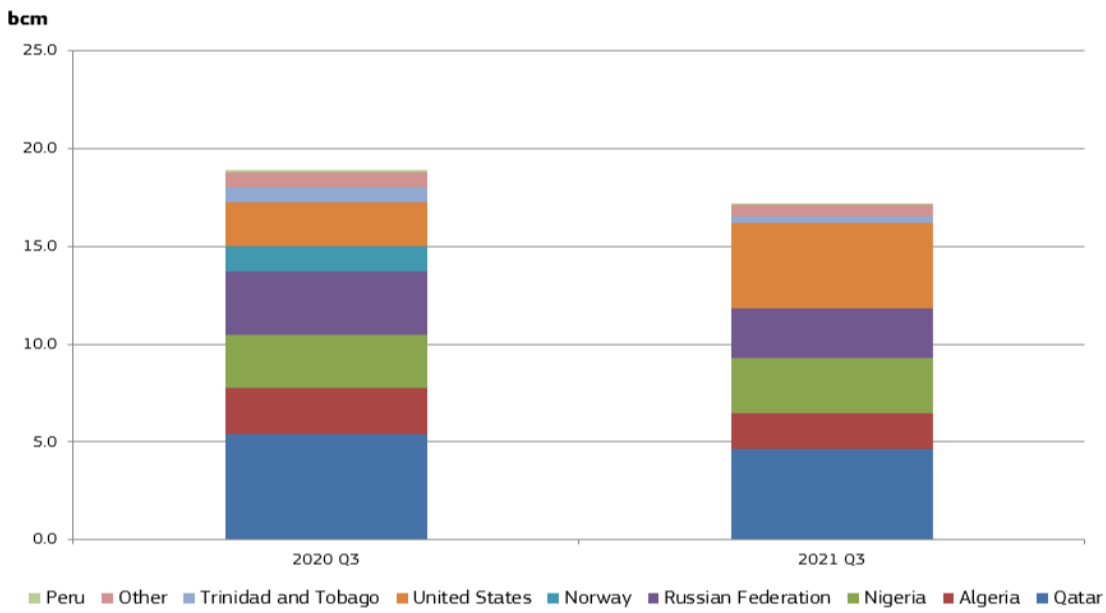
Figure 45 – LNG imports in the EU Member States, third quarters of 2020 and 2021



Source: Refinitiv

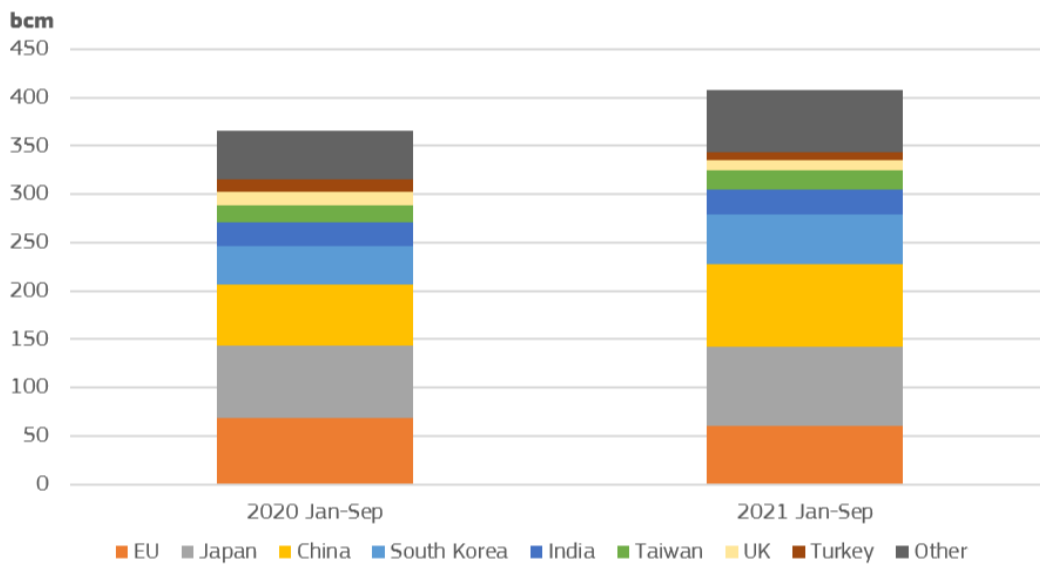
³⁴ These charts provide additional information on the main market developments, without textual comments and/or further detailed analysis

Figure 46 – LNG import from the main suppliers to the EU in the third quarters of 2020 and 2021



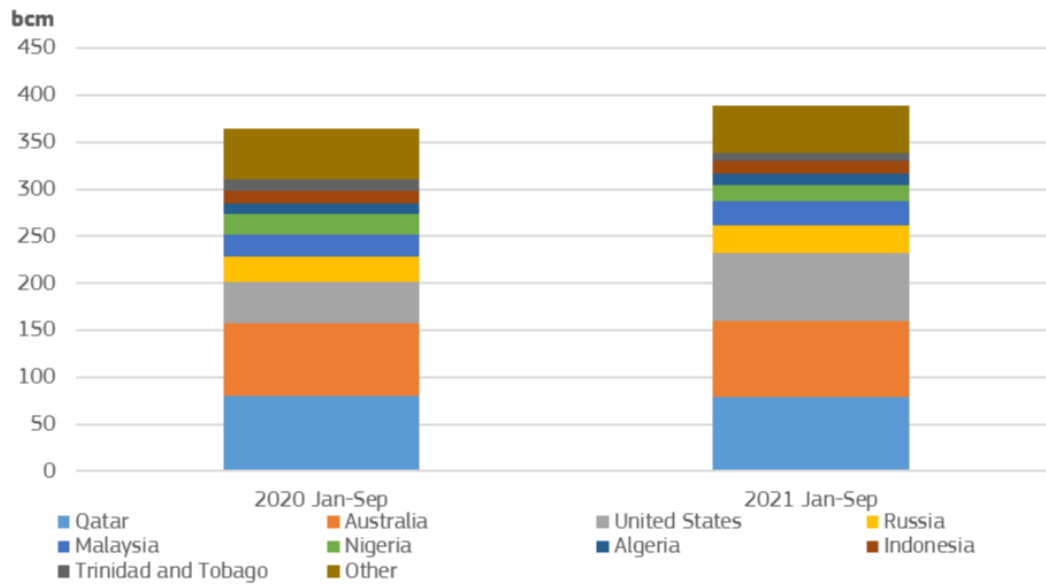
Source: Refinitiv

Figure 47 - LNG imports in the main consumer markets in January-September 2020 and 2021



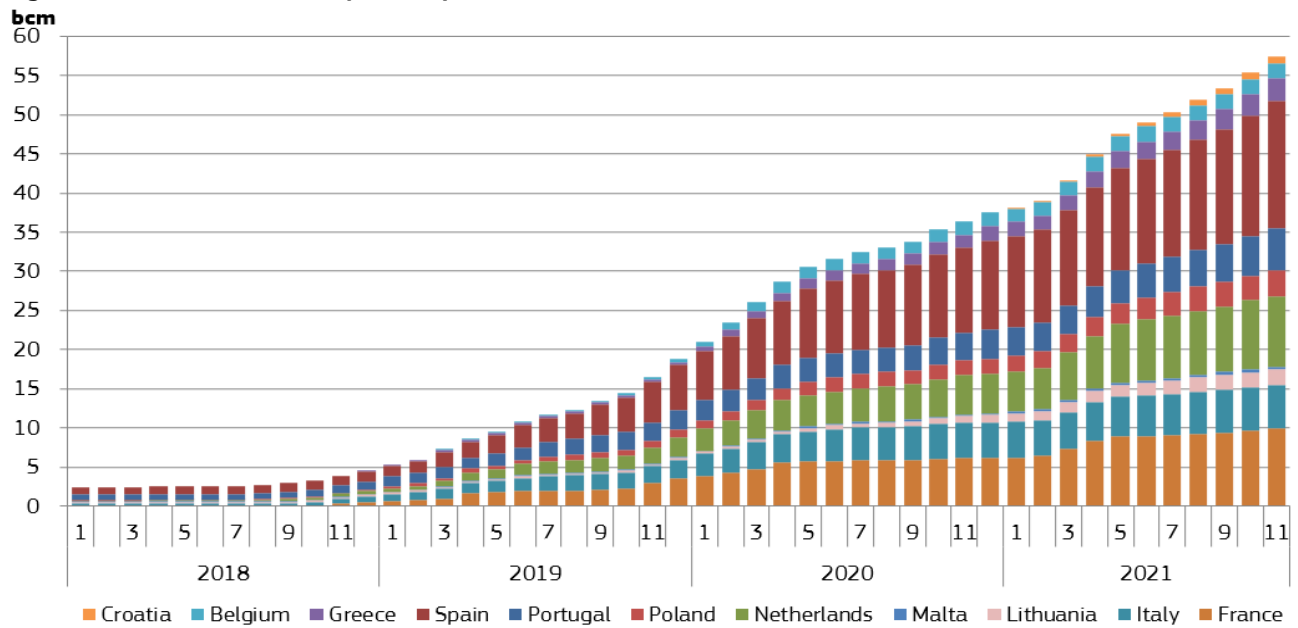
Source: Refinitiv

Figure 48 - LNG exports in the main consumer markets in January-September 2020 and 2021



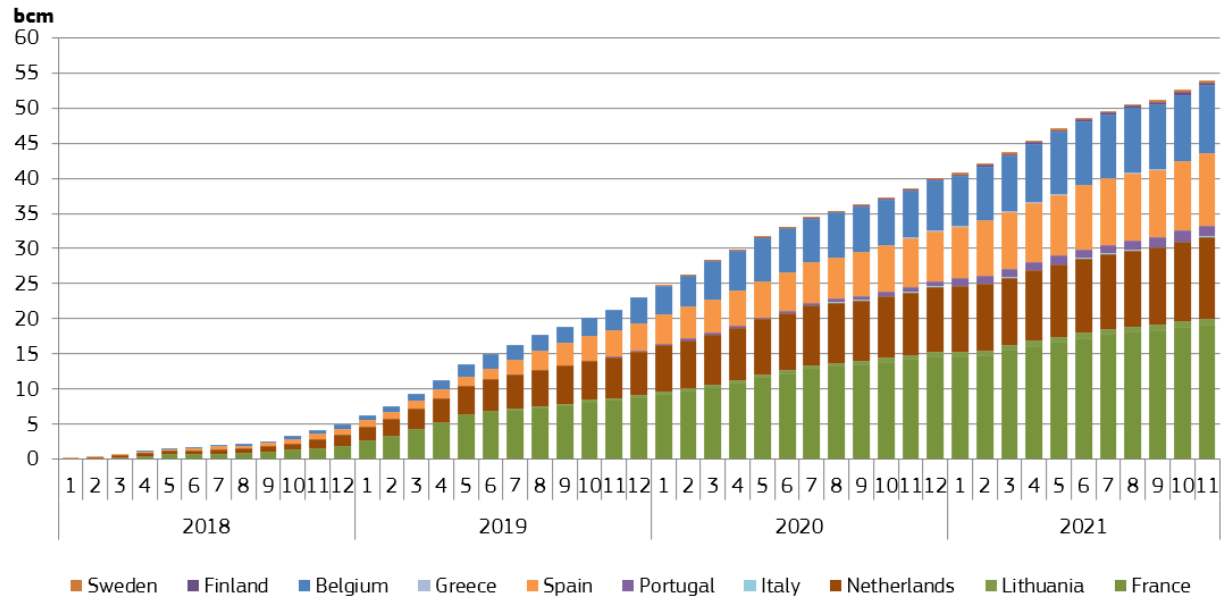
Source: Refinitiv

Figure 49 - Cumulative monthly LNG imports from the US in the EU



Source: Commission calculations based on tanker movements reported by Refinitiv

Figure 50 – 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.