ACER

European Union Agency for the Cooperation of Energy Regulators

CEER

Council of European Energy Regulators

European gas market trends and price drivers

2023 Market Monitoring Report

October 2023

Legal notice

The joint publication of the European Union Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators is protected by copyright. The European Union Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators accept no responsibility or liability for any consequences arising from the use of the data contained in this document.

European gas market trends and price drivers

2023 Market Monitoring Report

October 2023

European Union Agency for the Cooperation of Energy Regulators

Council of European Energy Regulators

Find us at:

ACER

E press@acer.europa.eu

Trg republike 3

1000 Ljubljana

Slovenia

www.acer.europa.eu

CEER

E brussels@ceer.eu

Cours Saint-Michel 30a/F

BE-1040 Brussels

Belgium

www.ceer.eu

Contents

List of Figures

List of Tables

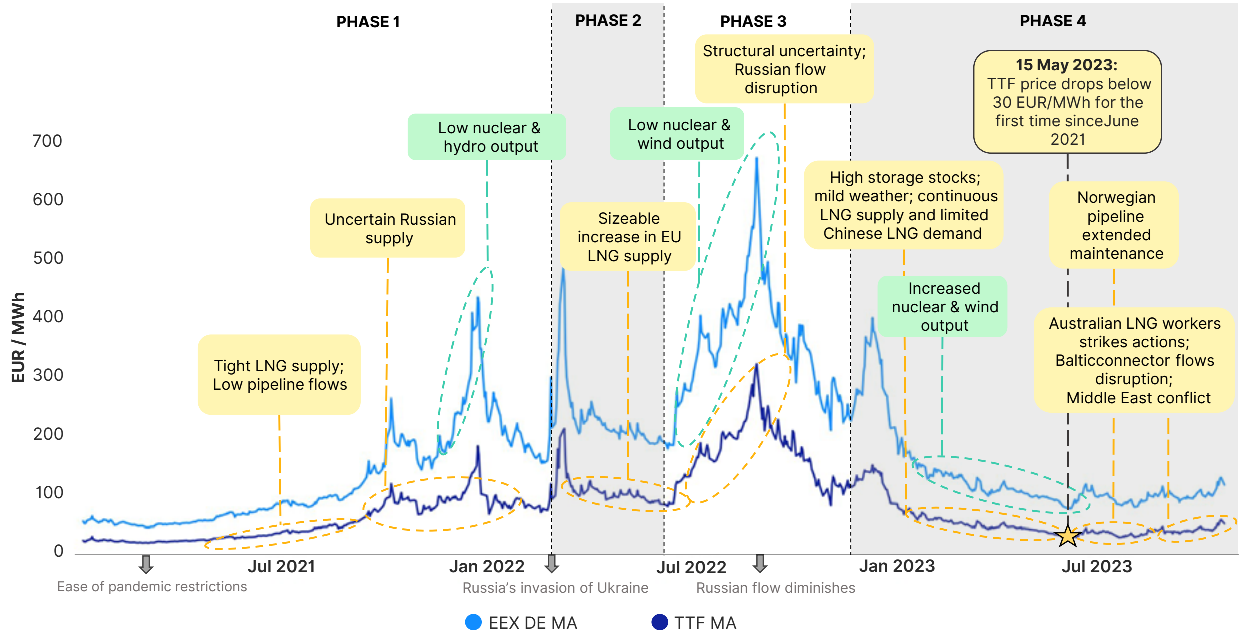
Executive Summary

1 This report, jointly published by the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER), examines the drivers that led to the unprecedented price rise in European gas markets in the summer of 2022. The report is an integral part of the annual 2023 Market Monitoring Report (MMR).

Introduction: Restricted Russian gas supply significantly affects the EU energy landscape

2 Figure 1 illustrates the evolution of the European Union's (EU) gas and electricity prices from mid-2021, along with relevant market fundamentals. The focus of the report is on revising the market developments during the summer of 2022 (Phase 3) when EU gas prices peaked.

Figure 1: EU gas and electricity prices and relevant market fundamentals (EUR/MWh) - May 2021 - October 2023



Source: ACER based on Platts' price data.

Note: The Dutch Title Transfer Facility gas hub (TTF) and the German European Energy Exchange (EEX) month-ahead contract prices are used as benchmarks for gas and electricity pricing respectively.

3 The report concludes that the primary cause of the gas price surge across the summer of 2022 was the drop in Russian pipeline gas supplies, which triggered intense price competition among buyers to secure additional gas resources. Most of the extra gas supplies were procured through costly spot LNG deliveries in competition with global LNG buyers. Rising gas demand, related to both the build-up of storage inventories ahead of winter and constrained non-gas-based power capacity resulting in a growing use of gas-fired power plants also contributed to exerting upward pressure on prices. Moreover, highly congested access to pipelines and LNG terminals in North-West Europe - an outcome of the EU supply shift from Russian pipeline gas - and an overall more challenging trading environment added to the significant constraints.

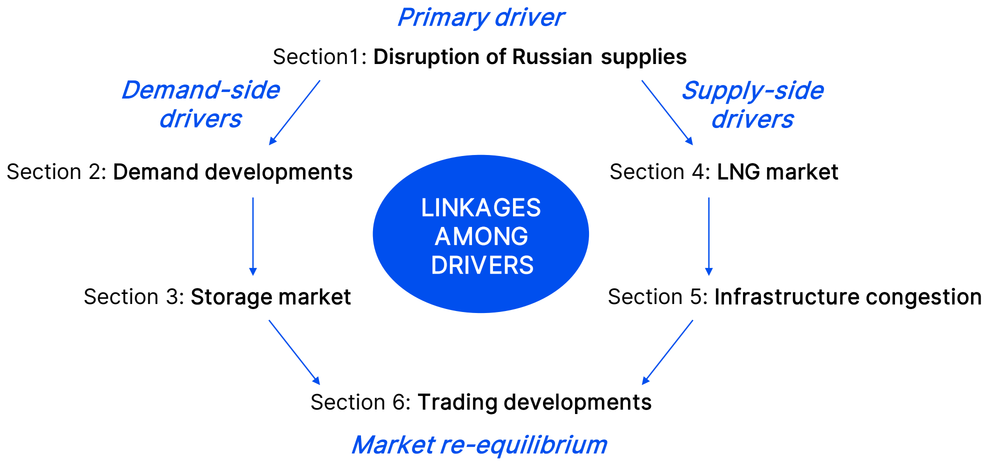
4 From October 2022 to September 2023 (Phase 4), prices gradually decreased due to a range of factors leading together to a more favourable EU demand-supply balance[1]. Chapter 1 offers an overview of the more favourable EU gas market developments in recent months[2].

1 Council Regulation (EU) No 2022/2578, tasked ACER and the European Securities and Markets Authority (ESMA) with publishing two reports to assess the market effects resulting from the Market Correction Mechanism (MCM), adopted in end- December 2022. Neither ACER nor ESMA identified significant effects (positive or negative) that could be unequivocally and directly attributed to the adoption of the MCM.

2 For this, ACER uses the same market indicators provided in its reports assessing the market effects of the MCM. On 27 June 2023, ACER also issued a MMR Report summarising the key EU gas market developments until that date.

Summer 2022 developments: key findings, implications, and recommendations

5 To ensure a more organised and comprehensive report, the drivers that led to the unprecedented price rise in 2022 have been categorized into six distinct segments across Chapter 2. This is despite all the drivers being interlinked.



i. Key findings

6 ACER lists six primary conclusions on the gas market developments during the summer of 2022.

1. The disruption of Russian supply was the primary driver affecting EU gas prices.
2. EU gas consumption fell over 50 bcm in 2022. However, additional demand in summer months, driven by larger storage injections and rising gas-fired power generation contributed to the record-high prices.
3. The implemented storage measures managed to attract substantial gas volumes ahead of winter 2022/2023, but in some instances incurred high injection costs.
4. LNG played a crucial role in safeguarding EU gas supply, but costly spot LNG imports drove hub prices up. The rapid development of LNG infrastructure was overall effective.
5. The EU's integrated gas system demonstrated resilience. Yet, the severe supply shock led to highly congested access to LNG terminals and pipelines, causing price disparities and trading disruptions.
6. Hub trading volumes remained robust despite the surge in trading margins caused by the record-high prices. However, the trading environment was more challenging.

ii. Forward-looking implications

7 The Russian supply shock prompted a major rebalancing of the EU energy market that will have a lasting impact. There are valuable lessons and conceptual forward-looking implications to be considered for enhancing the resilience of the EU internal energy market in the future.

1. Implications related to a higher EU dependence on LNG supply

EU gas prices will be more exposed to global competition going forward. This circumstance stems from the EU's growing reliance on LNG supply. This situation will likely increase the volatility of EU gas prices, which might subsequently affect electricity prices. Moreover, considering the systemic impacts of energy prices on the EU economy, factors such as inflation, the international competitiveness of EU industries and the pace and scale of the investments aimed at decarbonizing the EU economy could all be influenced. Furthermore, as the gas market transitions towards an increased reliance on LNG, safeguarding its competitiveness and integration levels remains crucial. An important element in that respect relates to enhancing the transparency of the new LNG terminals' access regimes, to prevent any stifling of healthy competition.

2. Implications related to the redistribution of collected revenue

The actions taken to restore the EU's gas market balance in the summer of 2022 brought about challenges and opportunities for gas producers, suppliers, transmission system operators and traders, whilst overall having a substantial impact on energy-intensive consumers. Designing appropriate and targeted mechanisms for the redistribution of extra collected revenues to alleviate high costs, while at the same time fostering the large investments that the EU needs to meet decarbonisation goals is a complex challenge. Policy makers need to further reflect on this aspect[3].

3. Implications related to the evolution of gas demand

A pressing challenge is finding the most efficient means to reduce the EU's conventional gas demand to adjust it to a tight supply market and assist the decarbonisation goals while preserving the economic activity and the security of supply that gas offers to the EU's energy system. The pace of gas demand reduction carries important near-term and long-term contractual implications. In this context, it is important to increase the flexibility of the less responsive segments of gas demand, as these segments will continue to influence short-term gas prices significantly. Furthermore, the substitution of conventional gas for alternative energy supplies could impact the competitiveness of energy-intensive industries relying on gas.

4. Implications related to the role of underground storage

Another area that has forward-looking implications relates to how engaging a sufficient market response that enables sufficient storage injections based on economic signals, whilst limiting public support interventions. It is important to extract lessons from the summer 2022 experience. ACER and CEER are willing to contribute to the discussion with two forthcoming consultancy studies on the matter.

iii. Recommendations

8 Considering the market developments of the summer of 2022, and with awareness of the forward-looking implications discussed above, ACER highlights the following nearer-term recommendations:

i. Recommendations pertaining to gas demand:

1. Member States to maintain political commitments to reduce gas consumption.

2. National regulatory authorities to evaluate the efficiency of the demand reduction measures implemented in 2022 and share findings with political decision-makers.

3. Member States to primarily direct financial support to promoting demand savings and efficiency investments, instead of subsidizing final supply costs.

4. Members States, Transmission System Operators, and industry associations to closely monitor risk preparedness to ensure an effective and swift response in case new market shocks materialise.

ii. Recommendations pertaining to network congestion[4]:

5. Neighbouring Transmission System Operators to extensively coordinate and jointly maximise the availability of firm and interruptible capacities.

6. Neighbouring National regulatory authorities to extensively coordinate and remove any regulatory obstacles that prevent the optimal use of the existing network.

3 In July 2023 ACER published its Assessment of emergency measures in electricity markets, revising the effectiveness of the measures that government used to shield consumers against prices, such as allocating funds from national budgets and granting tax exemptions. The Organisation for Economic Cooperation and Development (OECD) has published in September 2023 an overview of the windfall profit taxes, solidarity levies and other redistribution measures introduced by EU Member States during 2022.

4 ACER initially stated these four recommendations in ACER's Special Report on dealing with congestions.

7. Transmission System Operators to carefully consider the need for investment where physical bottlenecks remain after the operational optimisation of the existing network.

8. National regulatory authorities to carefully assess the appropriateness of the investments that remove structural bottlenecks, while mitigating the potential of future asset stranding. Congestion revenues may be used to finance such network investment[5].

iii. Recommendations pertaining to LNG import infrastructure:

9. Regulatory authorities to overall promote transparent access regimes to LNG infrastructure, not to endanger the EU gas market integration and competition levels.

10. Competent authorities to thoroughly monitor LNG import capacity concentration and use, to prevent potential capacity hoarding[6].

9 Finally, in a broader perspective, ACER stands aligned with the European Commission, Member States, and the energy sector in their efforts to enhance the diversification of the EU energy mix, and to strategically shift away from a heavy dependency on Russian gas.

5 Without prejudice to the forward-looking implications related to welfare redistribution as discussed above.

6 The forthcoming ACER-CEER LNG Market Monitoring Report, to be issued early March 2024, shall contribute to that effort.

1. Gas market trends

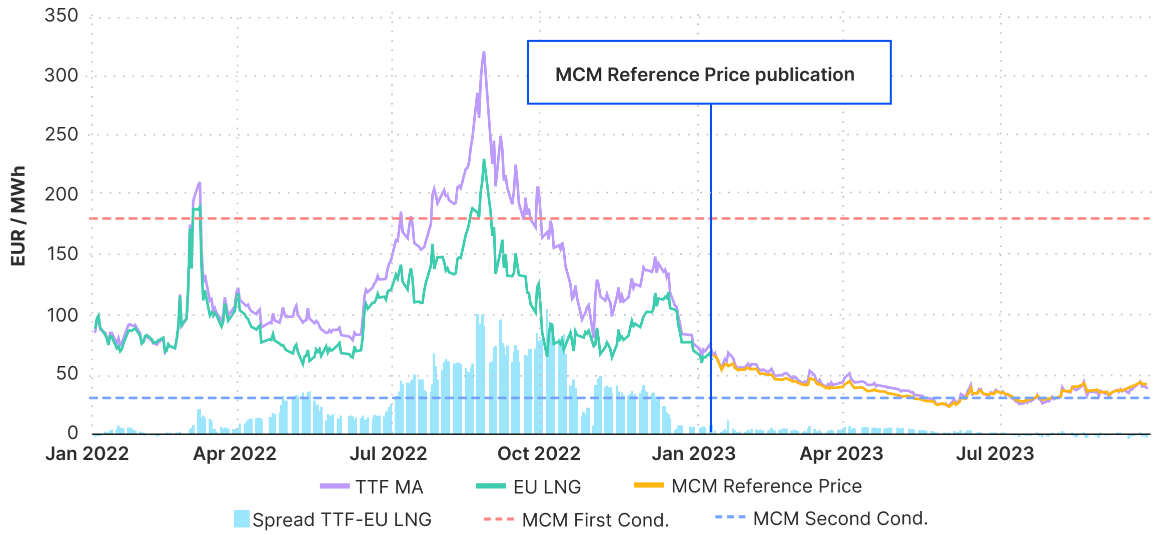
10 To analyse the latest trends in European gas markets, Chapter 1 updates the values of the market indicators used by ACER when monitoring the effects of the market correction mechanism in its two dedicated reports issued in January and March 2023 respectively[7]. The indicators are distributed across the four following areas: price-evolution, demand-supply balance, infrastructure utilisation and trading activity.

1.1. Price indicators

11 This section contains three analyses to illustrate the evolution of EU gas prices in the last months, along with a concise summary of the drivers that are influencing price formation. The assessment also offers some considerations about the future gas price outlook. A more thorough assessment of the different drivers that took responsibility for the unprecedented gas price rises in 2022 will follow in Chapter 2.

1.1.1. Gas hubs and LNG price evolution

Figure 2: Front-month TTF, EU LNG spot and MCM Reference Price evolution (EUR/MWh) – January 2022 – September 2023



Source: ACER calculations based on Platts, Argus and ICE Endex.

Note: 'EU LNG Spot' prices, assessed until 1 February 2023, correspond to the average second half-month prices for delivery in North-West Europe and Mediterranean area assessed by Platts. The actual MCM reference price is calculated in accordance with the MCM Regulation methodology, and it is assessed from 1 February 2023 when the ACER mandate to publish the MCM reference price entered into force.

- Since Q4 2022 and during 2023 EU gas prices have decreased significantly. In the months of June 2023 to August 2023, the average TTF front-month price used as the EU benchmark was 32 EUR/MWh, which is a -438% drop compared to the prices in the same period in 2022. However, prices remain 1.45 times higher than the 2017-2021 average.

- An improved balance between European gas demand and supply has facilitated the decrease of EU hub prices. Depressed demand along with increasing EU LNG imports have largely compensated for the drop in Russian pipeline supply. Nonetheless, EU gas supply options remain overall constrained, making prices volatile and susceptible to increases when unforeseen events occur[8]. For example, in the first half of October 2023 TTF spot prices have surged by circa 30%, surpassing the 50 EUR/

7 See footnote 1.

8 To illustrate this point, from 13 to 16 June 2023, TTF day-ahead prices experienced a significant increase of 10 EUR/MWh following the announcement of an extended maintenance period at a key Norwegian interconnector. Another example took place on 10 August 2023, TTF month-ahead prices surged by 8 EUR/MWh, a rise of 30% in just one day, following news about potential strikes at Australian LNG facilities comprising around 10% of global LNG supply. The fallout of the Australian volumes would mean that Asian buyers would compete more aggressively for LNG volumes with European buyers. Although prices sharply receded from 22 August, following signs that the labour disputes would be solved, the high volatility revealed that EU gas supply flexibility options remain tight.

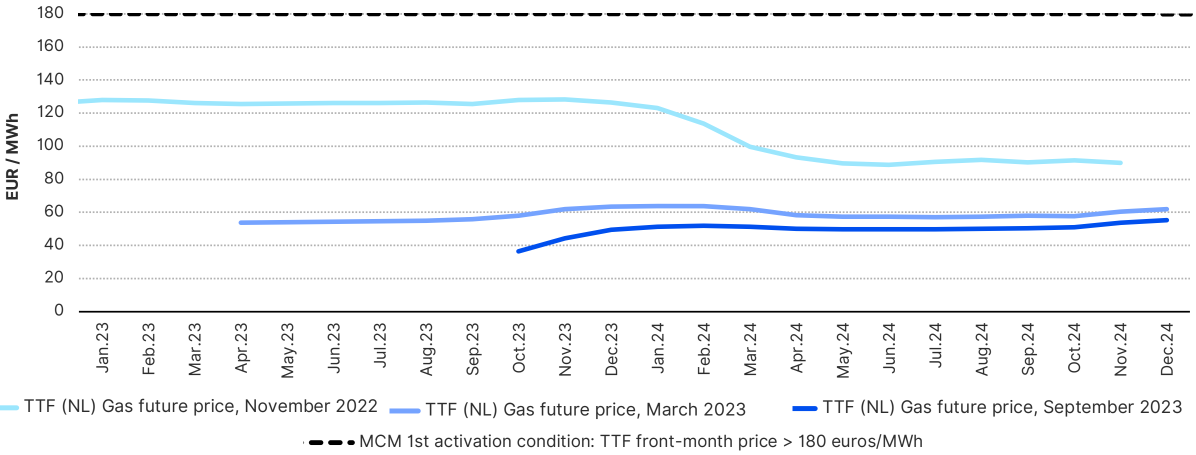
MWh reference for the first time since mid-February 2023. This increase has been driven by various factors, including the full disruptions in gas flows along the Finnish-Estonian Balticconnector following a presumed act of sabotage and the conflict in the Middle East. These two developments have introduced substantial additional uncertainties to the market.

- Asian LNG demand remains an important factor for EU gas price formation going forward. Overall, gas prices in the next months will be dependent on various developments, but chiefly driven by the resilience of EU demand and the global competition for LNG resources. In this context, the above-average underground storage stock levels offer higher security of supply ahead of winter 2023/2024. The next area of analysis offers further considerations about future gas prices.

- Figure 2 specifically assesses the evolution of TTF front-month prices in relation to an EU spot LNG price reference. Both elements are used by ACER for calculating the price conditions for the activation of the MCM, based on Articles 3 and 4 of the MCM Regulation[9]. TTF front-month prices have ranged between 23 to 44 EUR/MWh in the spring-summer period from 1 June 2023 to 31 August 2023. This is well below the price of 180 EUR/MWh which sets the first MCM activation condition. Moreover, the average price difference between TTF front-month products and the EU LNG spot reference price was 2 EUR/MWh in 2023 (1 January to 31 August 2023), reflecting a decrease in congestion at EU LNG terminals and selected IPs, implying that the second condition to activate the MCM is far to be met. The difference between TTF and spot LNG prices has gradually narrowed during the year. Interestingly, since August 2023, TTF front-month prices have been at a discount to spot DES NWE LNG prices. This trend primarily stems from the increased LNG regasification capacity, which eases access to EU gas systems and curbs the ability of LNG terminals' capacity rights holders to sell spot LNG at high premiums in EU gas hubs, but also due to moderate demand. Moreover, other contributing factors to reverse the latest price trend are the evolution of prompt and mid-curve EU hub product prices and of Asian spot LNG[10].

1.1.2. Gas future prices

Figure 3: Evolution of gas TTF future prices across 2023 and 2024 (EUR/MWh) – contracts negotiated in November 2022, March and September 2023



Source: ACER based on ICE Endex and European Energy Exchange (EEX).

- Futures and forward[11] prices became highly volatile in 2022. Market participants had to revise their contractual positions given the geopolitical uncertainties and the unstable supply and demand balances

9 Based on Article 3 of the MCM Regulation, ACER shall constantly monitor the development of a reference price, which is built on number of LNG price markers, and the front-month TTF derivative settlement price. ACER shall publish this reference price daily on its website no later than 23:59 CET. In accordance with Article 4 of the same regulation, ACER shall publish a notice stating in case a market correction event has occurred.

10 In August 2023, the prices of mid-curve hub products are higher than for prompt delivery. Additionally, spot LNG prices in Asian markets are higher than at TTF. Consequently, since August 2023, those EU buyers willing to procure spot LNG have been in need to pay a premium to TTF prompt prices, to encourage LNG suppliers to deliver the gas into the EU and mitigating any inclination to postpone shipments or redirect cargoes toward Asian markets.

11 Forward contracts are typically traded over the counter while futures contracts are typically traded on organised exchanges. They tend to be strongly correlated. Futures are used as generic across the text.

going forward. Future prices have fluctuated in a narrower band in 2023, amid more favourable EU gas market fundamentals, although price volatility remains above the historical average.

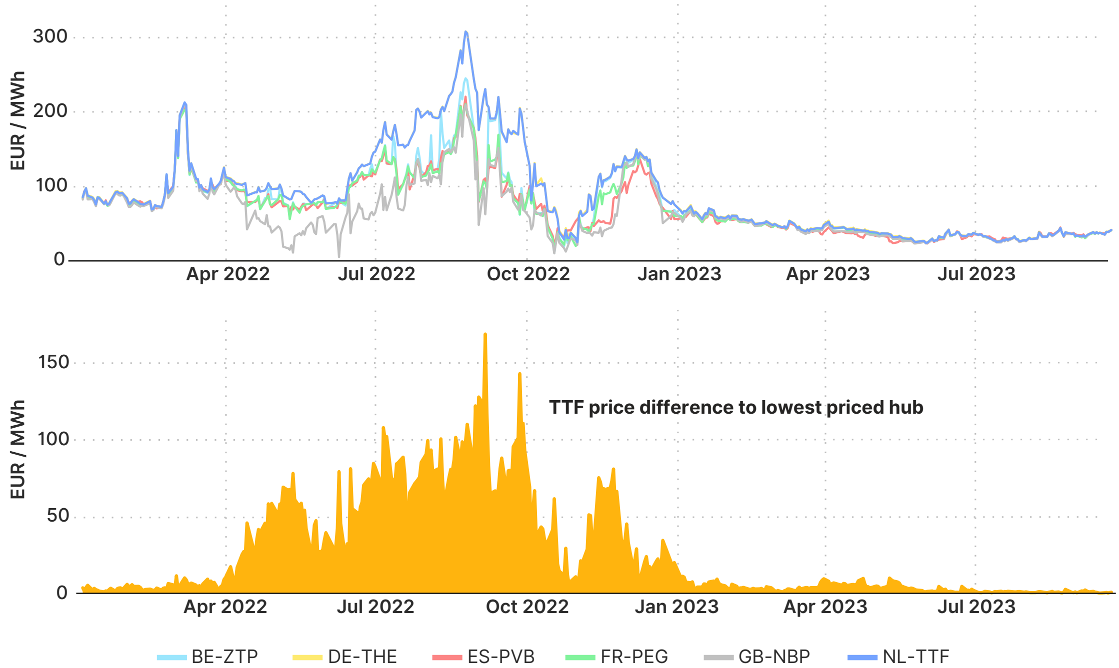
- Futures prices for gas delivery in winter 2023/2024 hover around 49 to 52 EUR/MWh in September 2023, showing a flattening trend across the subsequent seasons. These prices remain around 1.4 times higher than spot and prompt hub prices in the same period, indicating that the market sees higher supply risks for the forthcoming winter season. Furthermore, they are two times higher than the average of the five preceding winters, excluding 2021/2022 (i.e., 24 EUR/MWh). This price level for the next winter suggests the possibility of a further tightening European gas balance. This tightening could be driven by the still relatively limited new global LNG supply additions and a potentially reinforced global competition for LNG supplies (see and expanded analysis about the projected new LNG liquefaction capacities and demand prospects in the coming years in Section 2.4. Figure 36). Moreover, as the war amplifies in Ukraine, a continued downside risk to the remaining Russian piped flows to Europe remains a plausible scenario. Demand evolution would be at any rate key in determining the market balance and hence price levels.

- The significance of LNG imports to the EU is expected to grow consistently in the coming years, with LNG volumes expected to surpass pipeline gas sourcing by the end of the decade according to several projections[12]. This increasing reliance on LNG imports, combined with the growing influence of spot LNG volumes in determining marginal prices at gas trading hubs, will reinforce the role of LNG in shaping EU gas hub prices. Consequently, EU gas prices will be more exposed to global competition, as the LNG trading landscape expands and integrates the prices of several gas regions. Section 2.4. further emphasizes these aspects, underscoring the importance of the contractual equilibrium for LNG supplies.

- Natural gas demand is anticipated to further decline in the mid- and long-term driven by the growing electrification of European energy demand, energy efficiency investments and intensifying substitution of low carbon gases. Price formation will be closely tied to the dynamics of supply competition while meeting a decreasing gas demand. When looking at trading estimates for three-year-ahead products with limited liquidity, the prices for gas delivery in 2026 traded at TTF in September 2023 move around 33 to 38 EUR/MWh. On a long-time horizon, market intelligence analyses, such as Platts or ICIS Heren, refer to prices hovering between 25 EUR/MWh to 35 EUR/MWh for delivery in 2035 and onwards.

1.1.3. Hub price convergence

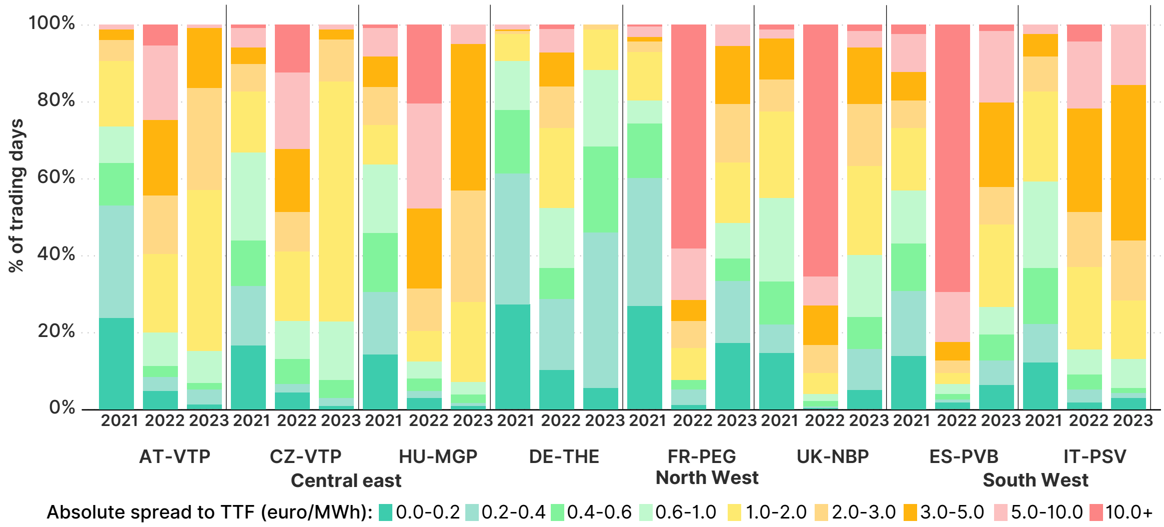
Figure 4: Day-ahead convergence between TTF and selected EU hubs (EUR/MWh) – January 2022 - August 2023



Source: ACER calculations based on ICIS Heren.

12 See for example the International Association of Oil and Gas producers study Rebalancing Europe's gas supply.

Figure 5: Day-ahead convergence between TTF and selected European hubs (EUR/MWh) – January 2021 - August 2023



Source: ACER calculations based on ICIS.

Note: The first graph shows the daily evolution of day-ahead prices traded at the five listed hubs, whilst the second graph shows the daily price spread between the Dutch TTF hub and the hub with the lowest price of the other four hubs.

- The significant price spreads of up to 150 EUR/MWh observed between some European hubs in the summer of 2022, were driven to a large extent by infrastructure constraints, namely the different capabilities of the Member States to access LNG to replace the lost Russian sources. These spreads have reverted to close to pre-crisis levels (i.e., from 1 to 3 EUR/MWh). The improving hub price convergence is overall indicative of reduced gas demand, increased availability of LNG import capacity and a less congested pipeline system.

- The Spanish PVB hub has shown the lowest day-ahead price levels in summer 2023, trading at an average discount of circa 2.2 EUR/MWh to TTF, the EU benchmark. The NBP in the UK and the French PEG hubs follow, trading at an average discount to TTF of 1.8 and 0.7 EUR/MWh respectively. Overall, the lower price levels at these hubs are the result of a higher available LNG regasification capacity.

- In North-West and Central Europe, hub price spreads tend to hover again around reference transportation tariffs, reflecting the decreased infrastructure congestion at LNG terminals in North-West Europe and at the gas pipelines flowing gas from West to East. As Section 2.5. will analyse, in the summer of 2022 tariff auction premia at selected and congested cross-border interconnections linking North-West Europe were extremely high and led to significant hub price spreads between hub pairs such as Belgium to Germany and Belgium to the Netherlands.

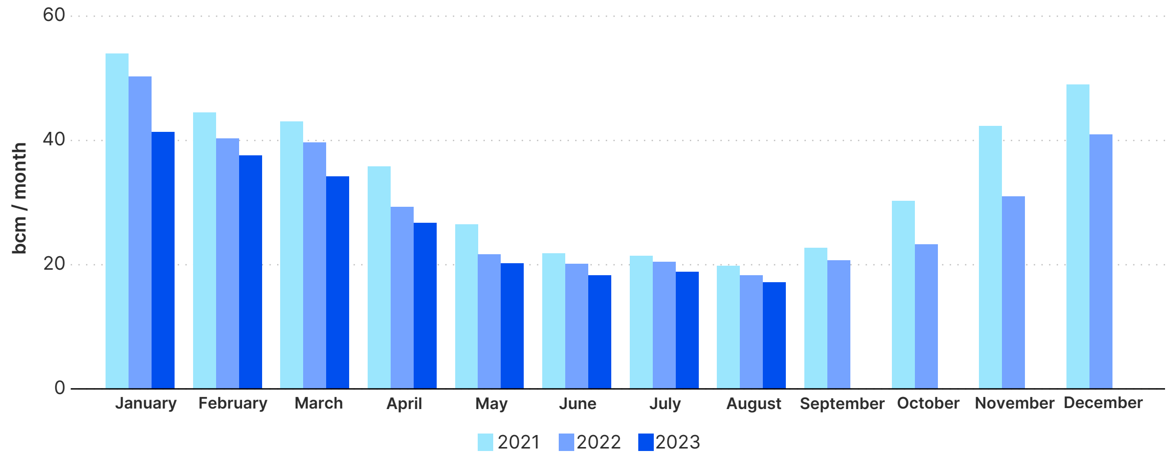
- Hub spreads are foreseen to remain at relatively low levels compared to 2022, even if they are still slightly above the historical average. Overall, the high storage levels at all EU gas markets and the lessened congestion have contributed to an increased hub price correlation, lower price divergences and the recovery of the EU gas and electricity markets to more normal levels of integration.

1.2. Gas supply and demand indicators

12 Several indicators are used in this section to assess the recent developments in gas demand and supply[13]. As stated, the balance between EU gas demand and supply has shown a gradual improvement since autumn 2022. The significant decrease in EU final gas consumption[14], along with the rise in LNG imports, has effectively compensated for the decline in Russian pipeline supplies.

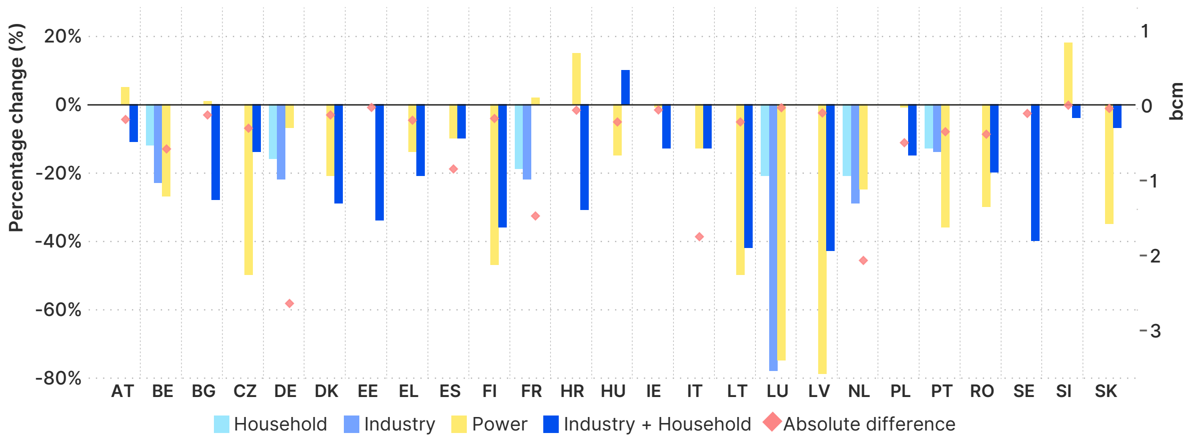
1.2.1. Demand evolution

Figure 6: Comparison of monthly demand evolution (bcm/month) – January 2021 – August 2023



Source: ACER calculations based on Eurostat.

Figure 7: Percentage and absolute change of total and sectorial demand evolution in selected Member States (% and bcm) – Q2 2023 compared to average values in 2019-2022



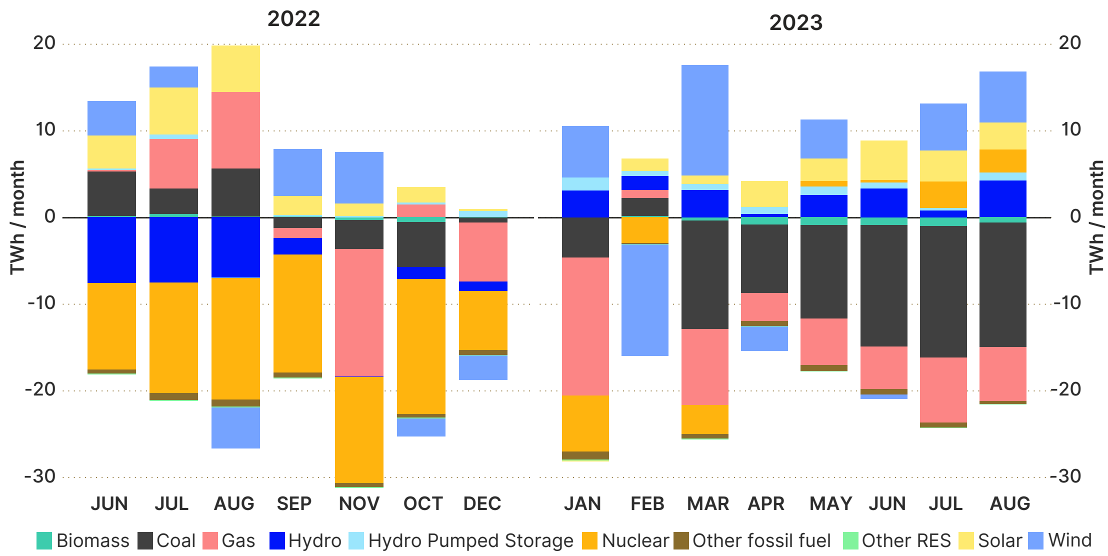
Source: ACER calculations based on Bruegel European natural gas demand tracker and Eurostat.

Note: For some MSs industrial and demand data can't be disaggregated.

13 The supply and demand indicators are chiefly based on ENTSOG TP and Eurostat data, but also use estimates from Platts and GIE such as in the case for LNG specific analyses.

14 Across this report, final consumption relates to the actual gas demand from households, industries and power-generation sectors, but also transport or agriculture. It does not consider underground storage injections. The sum of final consumption and storage injections is referred to as 'aggregated demand' or simply demand.

Figure 8: EU electricity generation year-on-year changes per month and per production technology (TWh/month) - June 2022 - August 2023



Source: ACER calculations based on ENSTO-E Transparency Platform.

- EU final gas consumption has registered a significant drop of 11% in 2023 year-to-date (i.e., from January to August 2023, in comparison with the same period in 2022). The decrease in EU gas demand in 2023 has been favoured by several factors:

    a. The relatively mild temperatures experienced from January to March 2023 led to reduced gas heating requirements at the beginning of 2023.

    b. The increased renewable and nuclear power generation has reduced gas consumption for electricity production in 2023 by 18% until August. This is in contrast to gas-fired power production rising by 3% in 2022 relative to 2021. Poland and Croatia, and to a lesser extent France and Ireland are an exception to that trend and have registered relative rises in gas-fired power production in 2023.

    c. The recovery in EU industrial gas consumption has been only marginal even if gas prices have substantially lessened in 2023 compared to 2022. The reduced industrial gas consumption has been the result of efficiency investments implemented, but also of outsourced or relocated production[15].

    d. Finally, government measures to reduce gas demand implemented in 2022 are kept in place to sustain gas demand reductions in 2023[16].

- When looking at the national level, the drop in demand in 2023 until August (compared with the same period of 2022) has been most significant in Greece, Estonia, Lithuania and Portugal, with relative drops in the vicinity of 20%. Weather specificities and the role of gas in the power generation portfolio and in the industry explain some of the differences. Figure 7 offers an overview of sectorial demand evolution per Member State in Q2 2023 in comparison to the 2019-2021 average, showing how reductions are being different across sectors and countries[17].

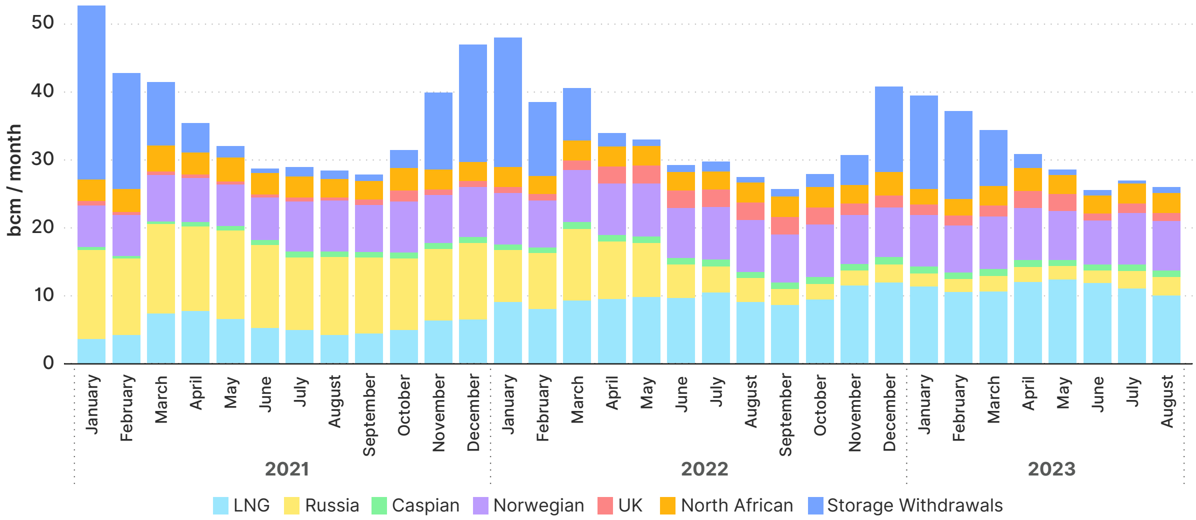
15 According to Bruegel, EU industrial gas consumption dropped by 15% in 2022 relative to the average in 2019-2021, while in 2023 the drop is 20%, relative to 2022. According to Platts, 8 bcm of industrial gas demand has been lost permanently, as a consequence of the price-driven demand response in Europe since the second half of 2021.

16 As discussed in Section 2.2.2, the Regulation setting a 15% demand reduction target has been maintained for the 2023 to 2024 period.

17 See for example Bruegel European natural gas demand tracker, analysing demand evolution per sector and MSs across 2022.

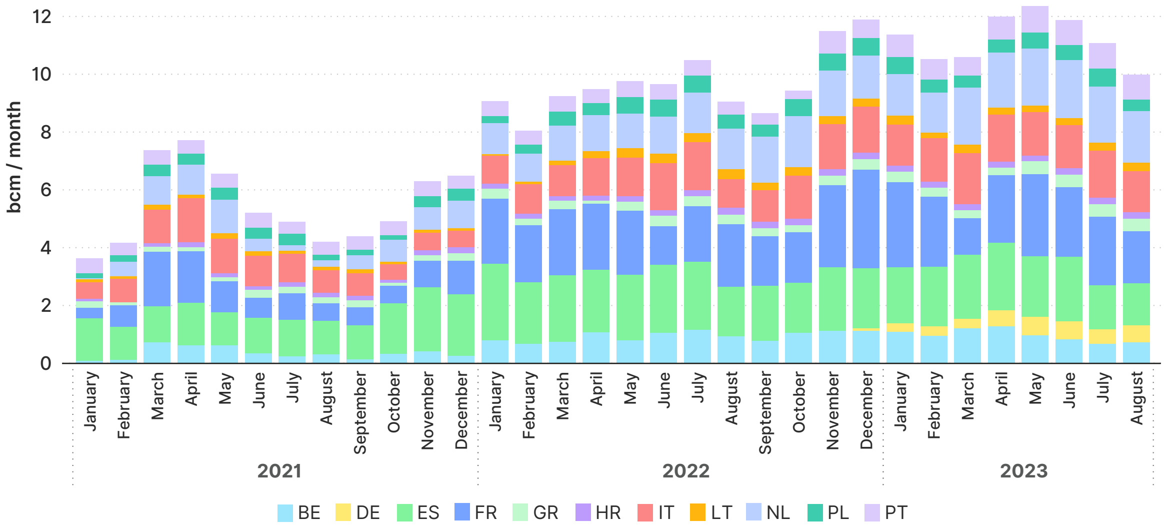
1.2.2. Supply evolution

Figure 9: Monthly evolution of gas deliveries into the EU by supply route (bcm/month) - January 2021 - August 2023



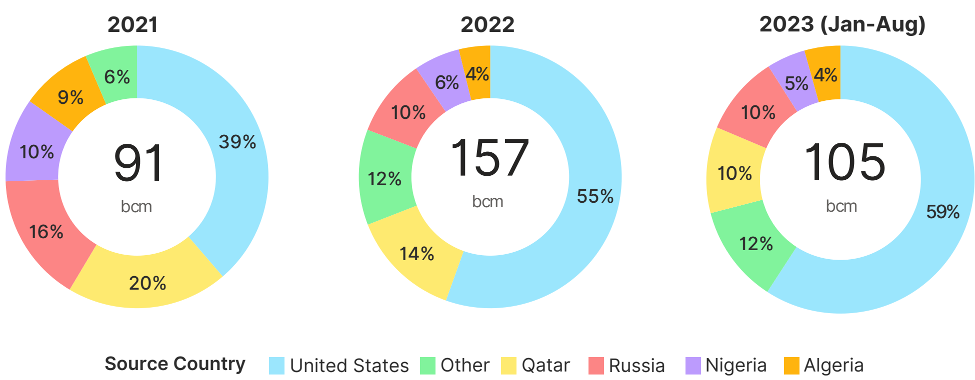
Source: ACER calculation based ENTSOG TP and GIE.

Figure 10: Monthly evolution of EU LNG send-out by Member State (bcm/month) - January 2021 - August 2023



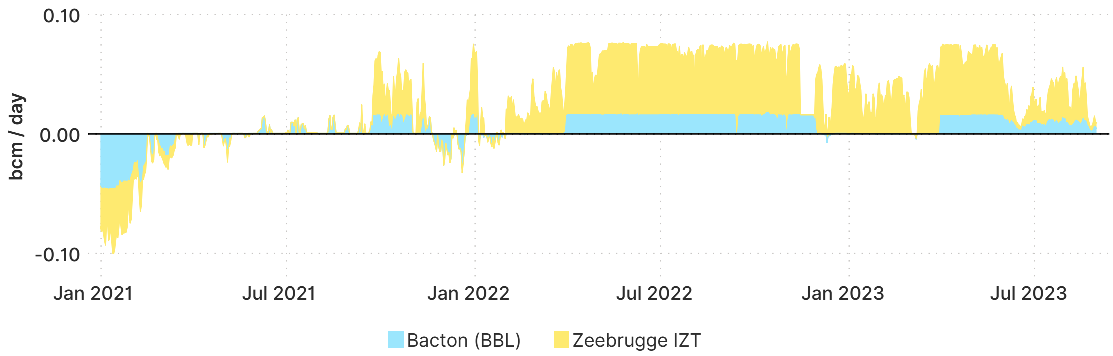
Source: ACER calculation based on GIE.

Figure 11: Share of EU + UK LNG imports by supply origin (%) – Total EU + UK LNG imports (bcm) - January 2021 – August 2023



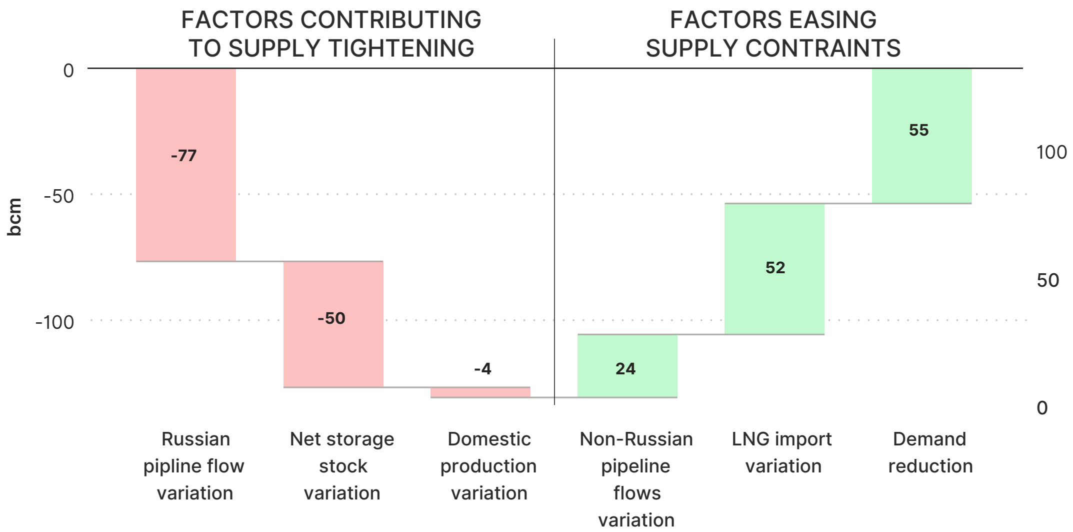
Source: ACER estimation based on Platts data.

Figure 12: Evolution of gas flows across the interconnectors linking the EU and the United Kingdom (bcm/day) – January 2021 – August 2023



Source: ACER calculation based ENTSOG TP.

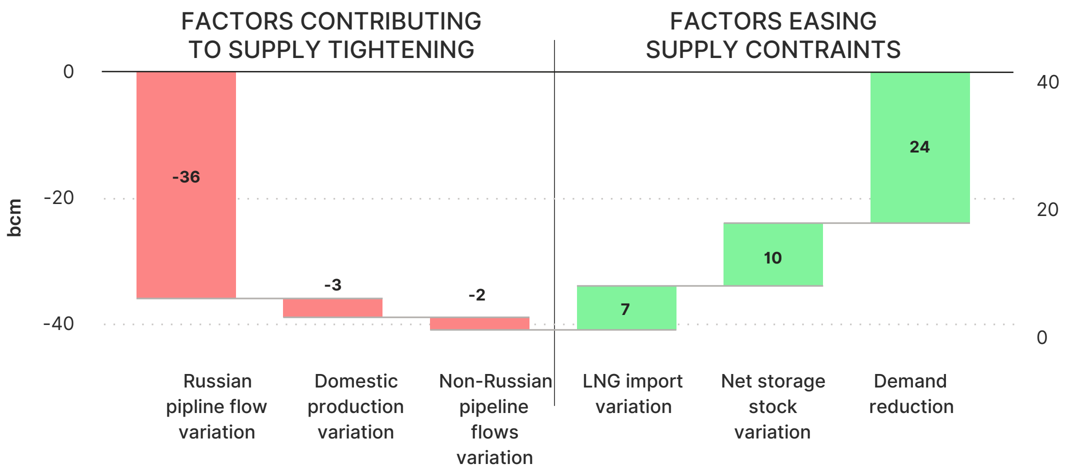
Figure 13: Estimated EU gas supply and demand differences in 2022 in comparison to 2021 (bcm)



Source: ACER estimation based ENTSOG TP, Platts, Eurostat and GIE.

Note: The assessment does not include the EU exports to third countries or losses. "Non-Russian pipeline flows variation" comprises also LNG imports in the UK reaching the continent through Interconnector and BBL.

Figure 14: Estimated EU gas supply and demand differences in 2023 in comparison to 2022 from January to June (bcm)



Source: ACER estimation based ENTSOG TP, Platts, Eurostat and GIE.

Note: The assessment does not include the EU exports to third countries or losses. "Non-Russian pipeline flows variation" comprises also LNG imports in the UK reaching the continent through Interconnector and BBL.

- Overall, across 2023, the reduction in Russian pipeline flows continues to be balanced by increasing EU LNG imports, along with consistent pipeline gas supply from Norway and Azerbaijan. Additionally, the net drop in final gas consumption and notably lower storage injections (in fact, rising net relative withdrawals) have allowed for the matching of the supply gap.

  a. Figure 13 illustrates the remarkable drop in Russian supplies occurring in 2022 compared to 2021. The drop forced the EU market to drastically rebalance its supply sourcing options. In 2022, Russian pipeline gas flows decreased by 55% (77 bcm less) from 141 bcm in 2021 to 64 bcm in 2022. Most of the supply decrease occurred in the second half of the year. This was offset by a 52 bcm increase in EU LNG direct imports, which reached 130 bcm, plus an estimated additional circa 16 bcm of LNG shoring in UK terminals and imported from the UK across the two offshore interconnectors. The analysis shows how a drop in final consumption of 55 bcm significantly contributed to easing the supply constraints. However, a rise of 50 bcm of net gas storage injections acted in the opposite direction, increasing gas demand and hence tightening the available supply.

  b. Figure 14 shows an analogous analysis for the year 2023, considering the period from 1 January to 30 June. Similar trends are observed compared to the same period in 2022. However, the relative year-on-year supply and demand changes are of a lower magnitude in 2023, as the market trends in 2023 have been more aligned with those observed in the second half of 2022. Until June 2023, Russian pipeline deliveries have totalled 12 bcm, which is a significant 36 bcm less than the sum of pipeline deliveries during the same period in 2022. In 2023, LNG imports have increased by 7 bcm relative to 2022 until June (28 bcm relative to 2021), signalling a reinforced reliance on LNG imports, enabled by significant LNG import capacities. Moreover, the net gas storage injections have been lower, easing supply constraints.

  c. Remaining Russian pipeline gas supplies into the EU are channelled through a few lasting long-term supply contracts between Gazprom and EU gas buyers in South-East and Central Europe, including Hungary, Austria, Slovakia, Greece and Croatia. These gas flows arrive through the Turk Stream and the Ukrainian corridors and are assessed to be paid in roubles. However, there is uncertainty regarding the continuation of some of these supply commitments going forward. Gazprom has the potential to disrupt the flows, whilst EU buyers may decide to further diversify their sources of supply. In addition, the transit and supply agreement between Gazprom and Ukraine, which underpins the flows of gas into the EU through Ukraine, is set to expire by the end of 2024. According to specialised market intelligence sources such as OIES, the chances of this agreement being renewed are limited[18].

- Figure 12 shows that net flows across the interconnectors linking the UK and the EU have kept being in a dominant import direction from the EU in 2023. While the interconnectors' utilisation ratios are on average slightly below those observed in summer 2022 (100% and 91 % June to August 2022, 49% and 39% June to August 2023), they consistently keep sending gas volumes imported through LNG terminals into continental Europe, taking advantage of the more ample LNG regasification capacities in the United Kingdom and avoiding bottlenecks within EU transmission.

- Section 2.4. in Chapter 2 discusses in more detail recent LNG market trends. The main EU LNG supplier is currently the US (circa 60% of LNG supply share throughout 2023), followed by Qatar and Russia. France has overtaken Spain as the top EU LNG importer, exhibiting the sharpest year-on-year increase among EU importers. The Netherlands, Italy and Belgium follow as the third, fourth and fifth largest LNG importing Member States.

18 As this OIES Paper analysing the future of Russian gas exports to Europe argues, on one hand, Ukraine may choose not to facilitate export sales for a wartime enemy and/or could demand excessively high transit fees. Conversely, there is an alternative perspective suggesting that Ukraine will choose to maintain gas flows to its European allies, benefiting from both transit fees and the option to import gas from Europe through virtual reverse flows. Russia's stance is also crucial, as it may seek a reason to terminate flows and attribute the blame to Ukraine's negotiating stance. Regardless, the transit of Russian gas through Ukraine, even at current low levels, is highly uncertain in the next 12-18 months.

1.3. Infrastructure indicators

13 The supply congestion scenario has improved in 2023 in comparison to 2022, as the lower demand and the new infrastructure investments are contributing to the easing of supply bottlenecks. Above all, the expanded regasification capacity at LNG terminals is gradually easing congestion issues and lessening the hub price spreads to more normal levels. However, the European gas market remains overall tight and hence exposed to unforeseen global gas market developments. The utilization ratios of various infrastructure pieces remain high as an outcome of the redirection of gas flows from west to east and the increasing volume of LNG deliveries to EU gas systems.

Figure 15: Overview of the utilisation ratio in selected EU IPs (% of firm technical capacity) – January 2019 – August 2023

Direction	Interconnection Point	IP Utilisation Rate Historical Average 2019-2021	IP Utilisation Rate Phase 1 01/04/2021 - 23/02/2022	IP Utilisation Rate Phase 2 24/02/2022 - 31/05/2022	IP Utilisation Rate Phase 3 01/06/2022 - 30/09/2022	IP Utilisation Rate Phase 4 01/10/2022 - 31/08/2023
UK > NL	Bacton (BBL)	43%	17%	99%	100%	66%
NL > UK	Bacton (BBL)	13%	13%	0%	0%	0%
AT > SK	Baumgarten	0%	0%	0%	0%	0%
SK > AT	Baumgarten	61%	63%	52%	28%	16%
HU > RO	Csanadpalota	34%	13%	21%	1%	1%
RO > HU	Csanadpalota	28%	36%	13%	80%	52%
EL > BG	Kulata (BG) / Sidirokastron (EL)	1%	1%	15%	26%	23%
BG > EL	Kulata (BG) / Sidirokastron (EL)	62%	63%	33%	10%	17%
PL > DE	Mallnow	80%	57%	5%	0%	0%
DE > PL	Mallnow	1%	6%	35%	21%	11%
HU > AT	Mosonmagyarovar	66%	31%	87%	56%	57%
LT > PL	Santaka			39%	43%	16%
PL > LT	Santaka			0%	1%	11%
IT > AT	Tarvisio (IT) / Arnoldstein (AT)	0%	0%	0%	0%	15%
AT > IT	Tarvisio (IT) / Arnoldstein (AT)	70%	65%	42%	22%	8%
DK > DE	VIP DK-THE	0%	0%	0%	0%	35%
DE > DK	VIP DK-THE	90%	77%	80%	49%	25%
FR > DE	VIP France - Germany					47%
DE > FR	VIP France - Germany	50%	60%	26%	13%	1%
AT > DE	VIP Oberkappel	12%	13%	0%	0%	5%
DE > AT	VIP Oberkappel	63%	34%	94%	104%	52%
ES > FR	VIP PIRINEOS	3%	6%	61%	16%	41%
FR > ES	VIP PIRINEOS	53%	34%	1%	28%	14%
DE > BE	VIP THE-ZTP			0%	0%	0%
BE > DE	VIP THE-ZTP			143%	150%	120%
NL > DE	VIP TTF-THE-H			41%	74%	99%
DE > NL	VIP TTF-THE-H			43%	17%	18%
NL > BE	VIP-BENE	5%	5%	0%	0%	0%
BE > NL	VIP-BENE	28%	32%	84%	101%	72%
FR > BE	VIRTUALYS	4%	59%	237%	336%	250%
BE > FR	VIRTUALYS	27%	10%	1%	0%	3%
BE > UK	Zeebrugge IZT	8%	7%	0%	0%	0%
UK > BE	Zeebrugge IZT	19%	10%	78%	92%	69%

Source: ACER calculation based on ENTSOG TP.

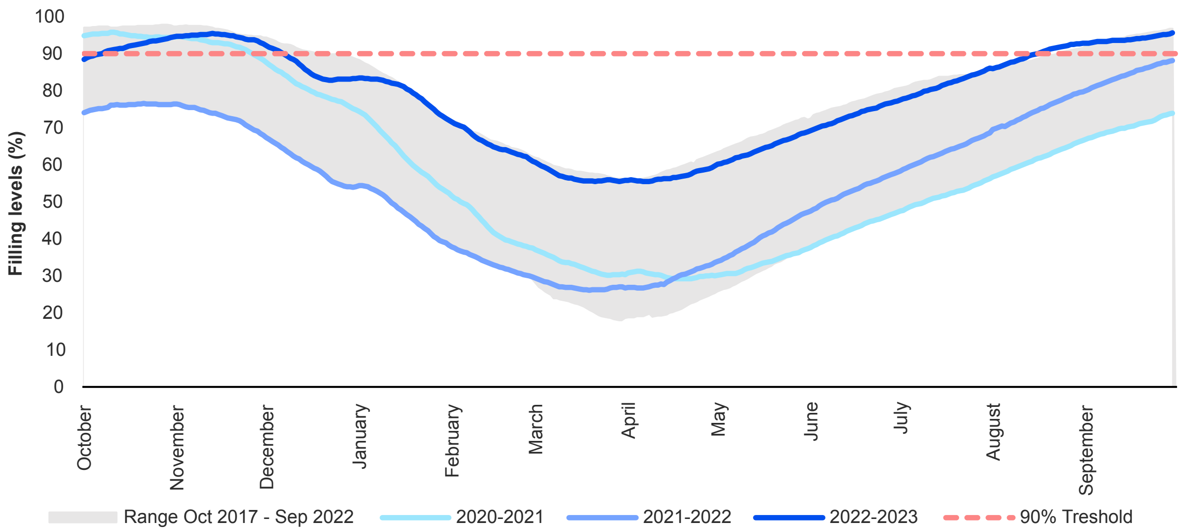
Note: Utilization ratios exceeding 100% can be attributed to methodological factors, the ratio is built as Physical flows over Firm technical capacity, however, flows can also be supported by interruptible capacity. Additionally, certain TSOs have recently maximized their capacity to facilitate increased flows, resulting in actual capacities surpassing the reported nominal capacity. Regarding Virtualys IP, it is understood by ACER that the reported physical flows include direct flows from the French Dunkerque LNG terminal into the Belgian transmission system.

Figure 16: Overview of the utilisation ratio in EU LNG terminals (% of maximum send-out capacity) – January 2019 – August 2023

Country	Terminal	LNG Utilisation Rate Historical Average 2019-2021	LNG Utilisation Rate Phase 1 01/04/2021 - 23/02/2022	LNG Utilisation Rate Phase 2 24/02/2022 - 31/05/2022	LNG Utilisation Rate Phase 3 01/06/2022 - 30/09/2022	LNG Utilisation Rate Phase 4 01/10/2022 - 31/08/2023
BE	Zeebrugge LNG Terminal	29%	28%	34%	64%	65%
DE	Brunsbuettel LNG Terminal 1					45%
DE	Ostsee LNG Terminal / Lubmin					23%
DE	Wilhelmshaven LNG Terminal 1					75%
ES	Barcelona LNG Terminal	23%	20%	19%	20%	17%
ES	Bilbao LNG Terminal	60%	58%	62%	74%	80%
ES	Cartagena LNG Terminal	16%	27%	29%	35%	29%
ES	Huelva LNG Terminal	33%	32%	33%	39%	39%
ES	Mugardos LNG Terminal	42%	52%	52%	55%	66%
ES	Sagunto LNG Terminal	16%	28%	31%	47%	38%
FR	Dunkerque LNG Terminal	25%	35%	47%	65%	67%
FR	Fos Cavaou LNG Terminal	48%	63%	69%	83%	84%
FR	Fos Tonkin LNG Terminal	49%	47%	48%	52%	49%
FR	Montoir de Bretagne LNG Terminal	53%	54%	63%	74%	71%
EL	Revythoussa LNG Terminal	27%	28%	28%	44%	49%
HR	Krk LNG Terminal	60%	71%	71%	89%	92%
IT	FSRU OLT Offshore LNG Toscana	41%	33%	38%	82%	66%
IT	Panigaglia LNG Terminal	42%	23%	28%	63%	80%
IT	Piombino LNG Terminal					13%
IT	Porto Levante LNG Terminal	89%	94%	95%	71%	89%
LT	FSRU Independence	37%	34%	42%	88%	79%
NL	EemsEnergy LNG Terminal				82%	65%
NL	Rotterdam Gate Terminal	41%	56%	65%	95%	90%
PL	Świnoujście LNG Terminal	61%	67%	71%	83%	86%
PT	Sines LNG Terminal	77%	84%	86%	84%	69%

Source: ACER calculation based on GIE data.

Figure 17: EU gas storage levels evolution (% of total capacity) – October 2017 – August 2023



Source: ACER calculation based on GIE data.

- The congestion scenario has improved in 2023 as lower demand and selected infrastructure investments are contributing to easing supply bottlenecks. As Figure 15 shows, the interconnection points flowing gas across North-West Europe in the west to east direction, including entry and exit-IP sides in the Netherlands, Belgium and Germany, remain the most highly utilised in relative terms. Selected ones such as the Virtual Interconnection Points from Belgium and the Netherlands into Germany are physically congested.

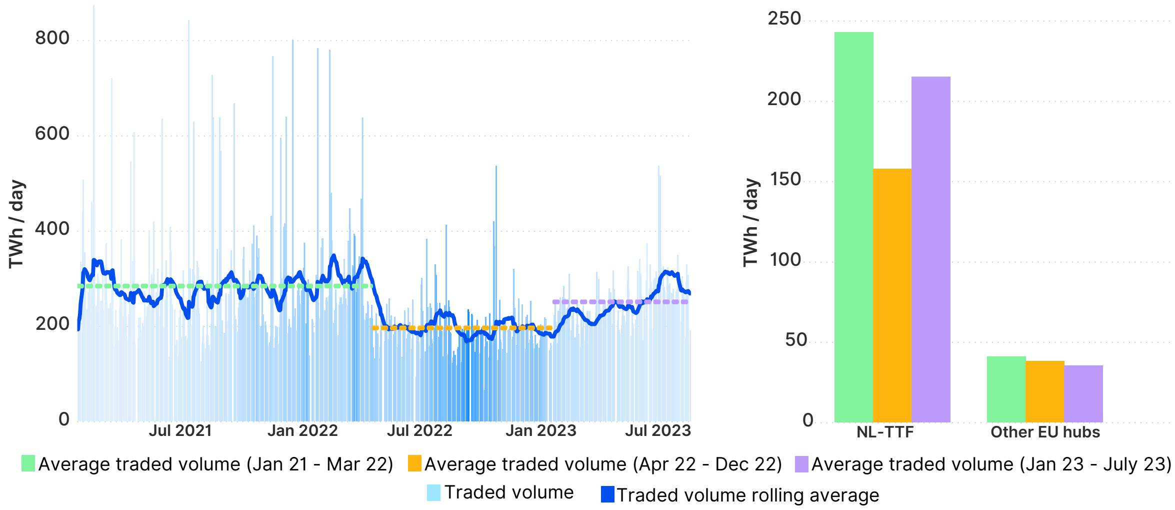
- The utilisation of most LNG terminals in Europe remains high in 2023, despite the additional capacity added in the North-West European and Baltic areas. Yet, that capacity addition is gradually resulting in an enhanced import flexibility. Available capacity remains the highest at the virtual Spanish system, which also is deemed to offer higher flexibility for spot cargoes. On a longer term and looking at the planned regasification projects (See Table 1 in Chapter 2) the investments will be dimensioned to meet high winter supply needs (whilst a high use of LNG terminals in summer will also back future storage injections) and as such it is expected that the supply constraints of LNG will be limited.

- Storage reserves are well above the average of preceding years (96%, on 30 September 2023 vs 87% on average in 2017-2022) and the 90% target filling level by November set within the Storage Regulation has already been met by the largest storage facilities and the majority of Member States well in advance.

1.4. Gas trading indicators

14 This section offers insights into the evolution of trading activity at EU marketplaces and the factors driving that since recently.

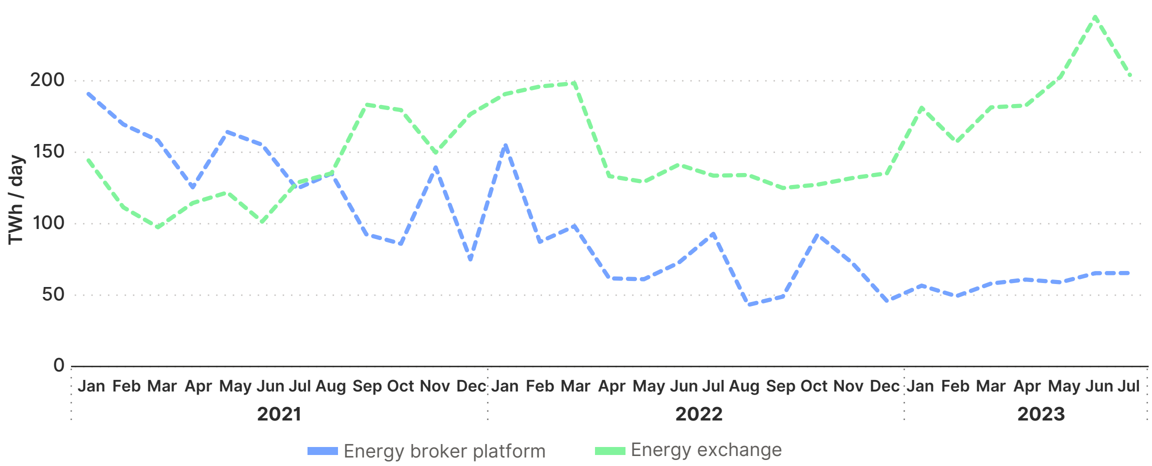
Figure 18: Exchange and brokered traded volumes at the EU gas hubs (TWh/day) – January 2021 – July 2023



Source: ACER calculation based on REMIT.

Notes: The rolling average corresponds to the average trades concluded in the preceding 30 days on a rolling basis. The intensity of the colour of the bars is related to the TTF front-month price, with darker tones corresponding to higher price levels. Results do not include data on options and swaps.

Figure 19: Brokered and exchange traded volumes at EU gas hubs (TWh/day) – January 2021 – July 2023



Source: ACER calculation based on REMIT.

Note: Results do not include data on options and swaps.

- European gas trading activity on organised marketplaces (i.e., energy exchanges and energy brokers) has increased in 2023 year-to-date compared with the more acute period of the energy crisis. However, trading volumes in 2023 remain marginally lower than the levels observed in 2021. The increase in transactional activity can be attributed to a number of energy trading conditions being relatively more benign when compared to the second half of 2022. Those include less capital required to hold futures positions, less supply uncertainty, and increased gas hubs' price correlation and convergence. At the same time, price volatility is incentivising both hedging and speculative trading.

- Gas futures contracts related to the Dutch TTF continue to attract the majority of European hub trading activity both when compared to other types of TTF contracts (i.e., spot and forward) or to contracts related to other European gas hubs. The German THE, French TRF and Italian PSV are EU gas hubs with the largest trading volumes after the TTF in 2023 so far.

- The relative shift in gas trading activity away from brokered to exchange based has continued in 2023. Brokered transactions used to represent up to three-quarters of European gas hub trading volumes prior to 2019. However, they are estimated to have accounted for less than a quarter of the volumes in 2023 so far. While brokered traded volumes have been increasing marginally since hitting a low at the end of 2022, the recovery in exchange trading has been much more pronounced.

2. Analysis of the drivers that led to the price surge in summer 2022

15 Chapter 2 examines the drivers that led to the unprecedented rise in EU hub gas prices across the summer of 2022. As stated, these drivers include sustained demand due to the build-up of storage inventories ahead of the winter and deteriorating power generation availability, congested access to pipelines and LNG terminals, strong competition for LNG resources in a tight global LNG market and trading factors. And above all, the disruption in Russian supplies.

16 When discussing trading factors, the chapter specifically draws on the detailed assessment carried out by the European Securities and Market Authority (ESMA) on the subject - The August 2022 surge in the price of natural gas futures - which has been published as part of ESMA's Report on Trends, Risks and Vulnerabilities series[19].

17 Quantifying the exact contribution of each driver to the gas price rises has not been possible. Firstly, because all these drivers are intertwined. And secondly, because the market shock triggered adaptive responses from market participants and policymakers, which shaped the different drivers' interrelations and effects. As such, as stated in the Executive Summary, the assessment leans more towards a qualitative approach, despite the analysis of several metrics and correlations.

18 Across the chapter, the overall significance of six drivers is interpreted in separate sections. For each section, ACER first introduces the relevance of each driver in gas price formation and then discusses the market context related to the driver during the summer of 2022. In doing that, ACER correlates metrics associated with the driver to the evolution of hub prices. Each section also argues potential alternative scenarios and lessons learned. To do that, ACER has leveraged the views of relevant stakeholders.

2.1. Driver 1: Disruption of Russian supply

2.1.1. Driver relevance: high dependency on Russian gas exposes the EU

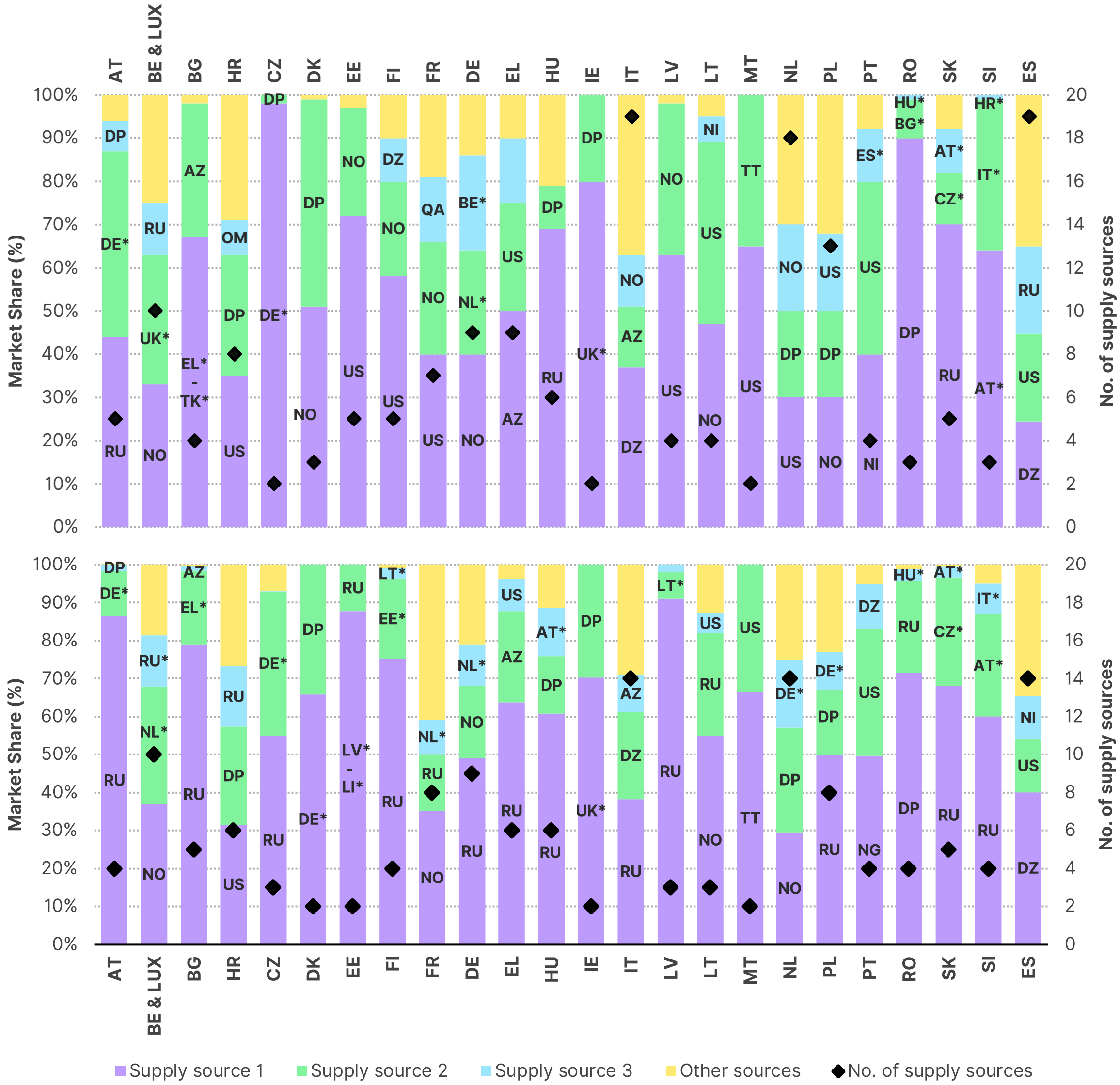
19 The EU gas market does not operate under perfect competition conditions[20]. There are various barriers to market access and restricted options for gas supply mainly due to the complexities involved in gas production, transport, and trading. These complexities are in turn influenced by geographical, geopolitical, financial and infrastructure constraints. Moreover, EU gas pricing and contracting follow a dual procurement model, where the hub model - characterised by competitive and transparent gas pricing and trading at organised market venues - coexists with long-term and bilateral contracting models, both with some different rationales.

20 Previous editions of the Market Monitoring Report have assessed the structural competition conditions of EU gas markets using the so-called 'market health' metrics. These metrics evaluate the number and concentration of supply sources, as well as the ability to meet demand relying solely on supply sources not under the control of the largest upstream supplier. Figure 20 analyses the gas supply diversification of EU Member States in 2023, compared to the same assessment in 2021.

19 Report on Trends, Risks and Vulnerabilities: The August 2022 surge in the price of natural gas futures. A summary of ESMA's main findings is included in Section 2.6.2.

20 In a perfectly competitive market, adequate numbers of buyers and sellers compete on equal terms and under full information, in the absence of entry barriers or individual market power to significantly influence prices. The market-clearing price is determined by matching supply and demand: suppliers will sell gas if they can sell it for a price that exceeds the marginal cost of production and buyers will procure gas as long as they benefit from the purchasing price.

Figure 20: Estimated number and share of supply sources in terms of the contractual origin of gas in EU MSs (% of actual volumes purchased) – 2023 (top) vs 2021 (down)



Source: ACER estimations based on ENTSOG TP, Eurostat and Platts data.

Note: The analysis represents an informed estimate of the market's gas supply contractual origins throughout the year per Member State, relying on combined data from various sources. The assessment considers domestic production as an independent supply origin and excludes storage withdrawals. An asterisk is placed when it is not possible to disentangle if the contractual origin of the gas is associated with a direct gas purchase at the national hub marked with an asterisk or a long-term pipeline contract or an LNG delivery whose source origin is not specified and is physically delivered across a cross-border interconnection point with the market marked with an asterisk. In 2023, Bulgarian imports marked as originating from Greece and Turkey* primarily pertain to LNG flows arriving in these two countries and subsequently imported into Bulgaria through the corresponding interconnectors. In the case of Croatia, there are no officially reported import flows from Russia in Eurostat data. However, market intelligence reports suggest that partial flows are associated with a prevailing long-term contract with Russia. In the Czech Republic, following the cancellation of a long-term supply contract with Russia, all imports are now attributed to Germany*. These imports encompass a combination of long-term contracts and direct purchases from hubs, which ACER has been unable to overlook. In those Member States with significant domestic production (DP) the supply share has been assessed considering the relative weights of the domestic production and imports relative to the final demand. In Denmark, biogas production has been included in the domestic production share, given its consistent relative volume and significance. In the case of the Netherlands, the assessment has been done considering the specificity of the low-calorific production exports to Germany and Belgium. In the Baltic Member States, gas is mainly sourced through the Lithuanian and Finnish LNG terminals; the assessment per individual Baltic Member State is proportionate to the LNG supply origins in these two countries and to the reported flows at cross-border interconnectors. Russian flows into Belgium, reported by Eurostat, could be subject to subsequent diversion as a result of the LNG transhipment agreement at the Zeebrugge Terminal[21].*

21 Fluxys has signed a deal with Yamal Trade that allows Russia's specialised ice-breaker LNG carriers to transfer Yamal LNG plant volumes to Zeebrugge into conventional LNG vessels, to allow regular onward shipments to Asia-Pacific and Middle Eastern markets.

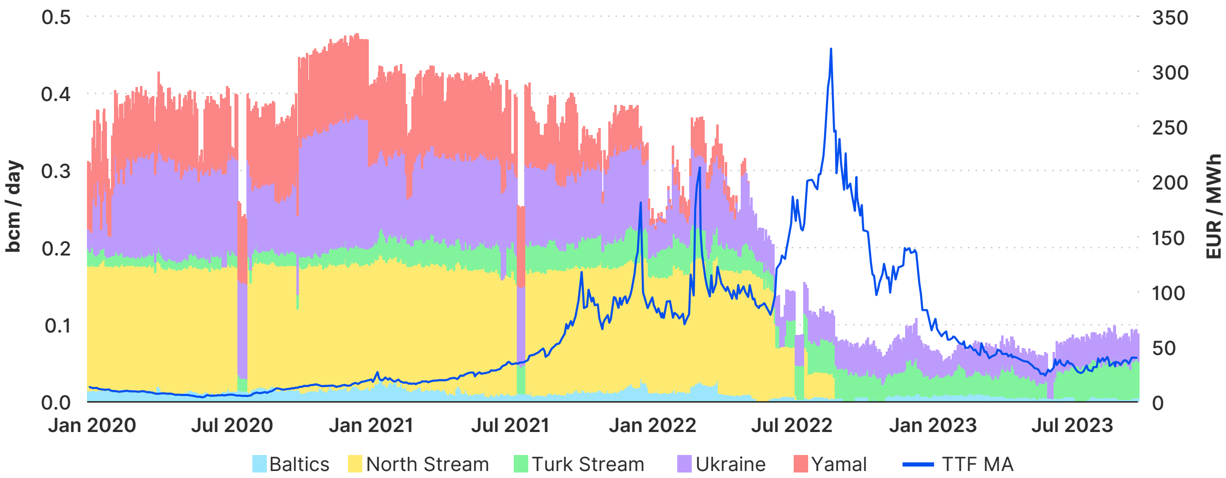
21 Figure 20 and other related structural competition analyses highlight the significant EU dependence on external gas imports, with Russia traditionally being the largest supplier of natural gas until 2022. EU domestic production, which used to play a more substantial role, has decreased by two-thirds since 2010, while gas consumption has only experienced marginal declines during that period, until the market shock in 2022 accelerated the EU demand drop.

22 In the last 10 years, the EU had started to take some steps to mitigate its reliance on Russian gas and diversifying its supply by means of increasing LNG imports and contracting supplies from alternative origins such as Azerbaijan. Additionally, various Member States have gradually increased the support for domestic biomethane production, which contributes to the diversification efforts of the EU. But those efforts proved insufficient and the events starting from mid-2021 exposed the EU's vulnerability to an unprecedented supply disruption.

2.1.2. Overview of summer 2022: supply uncertainty fuels price rises

23 The substantial decline in Russian gas supplied volumes and the overall uncertainty of Russian supply going forward was the main driver behind the unprecedented EU gas price rises occurring since mid-2021 and across 2022. Figure 21 introduces the Russian gas supply volumes per relevant supply corridor since mid-2020 and relates them against the evolution of TTF front-month hub prices, used as the EU price benchmark.

Figure 21: Overview of aggregated Russian supply into the EU per supply corridor (bcm/day) and correlation to TTF front-month prices (EUR/MWh) - 2020 – September 2023



Source: ACER calculations based on ENTSOG TP and Platts.

24 Traditionally, combined Russian pipeline and Russian LNG supplies had accounted for the largest fraction of the European market share[22], ranging from 35% to 45% from 2015 to 2021. Several factors have contributed to some annual variability in Russian gas share[23]. Most of the Russian pipeline gas supplies were procured via long-term supply contracts between European buyers and Gazprom, which in 2021 reached annual nominal contractual capacities of circa 175 bcm[24]. In addition, Gazprom also sold some volumes (i.e., up to 14% of its total supplies in 2020, a historical high) at hubs via its trading subsidiaries and auctioned volumes in its own Electronic Sales Platform. In the case of LNG, most of the Russian origin LNG volumes to the EU came from the Yamal LNG liquefaction plant, controlled by Novatek but also owned by minority shareholders, like Total Energie and Chinese stakeholders.

22 European market consists here of EU-27 plus the United Kingdom and Switzerland.

23 These factors included the overall EU gas demand needs, the extent of storage sites refilling and the flexibility provided by long-term contracts' nominations (EU buyers aim at optimizing their gas purchases by comparing and hedging gas procurement at hubs while considering the take-or-pay commitments and carry-forward clauses of their long-term supply contracts). Furthermore, the quantities of gas sold by Gazprom at EU gas hubs and through its auction platform were determined by Gazprom's commercial interests and available production capacities.

24 As a reference, EU Member States plus the UK and Switzerland imported around 141 bcm of Russian piped gas in 2021 to meet a total demand of 480 bcm that year. The various gas supply corridors linking Europe with Russia, sum more than 220 bcm of total nominal capacity, excluding Nord Stream 2.

25 However, from June 2022, the EU market share of Russian pipeline supplies dropped below 20% and moved gradually lower to its current level of 7% in September 2023. The decline followed a series of events, amidst the overall EU's concerted efforts to reduce its dependence on Russian energy supplies in response to the invasion of Ukraine.

26 Currently, only a limited number of long-term pipeline supply contracts are maintained between Gazprom and EU counterparties, which are delivered via the Turk Stream and Ukrainian corridors. Gazprom's hub trading activity has ceased, while key trading subsidiaries have been either shut down, sold, or nationalised by EU governments. Flows of gas have been completely disrupted through the Yamal and Nord Stream routes from May 2022 to September 2022. Russian LNG deliveries to the EU have on the contrary risen in 2022 and 2023, even if there are discussions about a potential ban on Russian LNG in the future.

27 As Section 1.2.2. has analysed, in absolute values, Russian pipeline flows to the EU accounted for 64 bcm approx. in 2022 in contrast to 141 bcm in 2021, with the bulk of the relative drop occurring since end-May 2022. It is projected that total Russian pipeline flows will amount to 25 bcm in 2023, with an additional 15 bcm sent as LNG.

28 A non-exhaustive list of the specific events that led to the gradual drop in Russian supplies into Europe since mid-2021 includes:

- **Increased political controversy over the entry into operation of the Nord Stream 2** interconnector, which also involved commercial sanctions from the United States[25]. The concerns related to increased dependency on Russian gas and the infringement of the EU's internal energy market rules. The political disputes led Russia to reduce gas supplies to some degree across distinct episodes, to Poland and Germany via Yamal, but also to Slovakia and Hungary. These reductions were perceived as an early indication of Russia's ability to restrict gas supplies to put pressure on the EU and its Member States. Notably, while long-term contract supply commitments were overall met, Gazprom halted selling volumes at EU gas hubs and since mid-October 2021 it fully discontinued the use of its own sales platform[26].

- **The frictions surrounding the long-term transit contract between Russia's Gazprom and Ukraine's Naftogaz**[27], had been creating uncertainty about the continuation of Russian gas transits through Ukraine and rising concerns about potential disruptions to the EU. Naftogaz filed a competition complaint to the European Commission in December 2021 accusing Gazprom of abusing its dominant position in the European gas market[28].

- **The introduction of pieces of legislation such as the European Climate Law**[29] **and the related measures aimed at achieving the EU's climate goals** by means of promoting renewable energy sources[30] are believed to have prompted Russia to try maximising revenues in view of the anticipated steady drop in EU gas imports. The EU and its Member States Energy and Climate plans promote renewables, hydrogen and biomethane to offset conventional natural gas and reduce import reliance. The Hydrogen and Decarbonised gas market package proposal issued in December 2021 protracted that ambition, while it also included provisions to enhance energy competition, transparency, and regulatory oversight in the EU gas market.

25 Yet, in August 2021, the United States and Germany reached an agreement to allow Nord Stream 2 completion aimed at addressing concerns about energy security and Ukraine's role as a transit country. The negotiated pact would impose sanctions on Russia in case it would use gas supplies to harm Ukraine or other countries in the region.

26 In parallel, to those early reductions, Gazprom trading arm purchased more short-term volumes at EU hubs in comparison with the preceding year, likely to back some long-term contracts' nominations. This strategy is thought to have resulted in increased price pressure on EU hubs.

27 Gazprom and Naftogaz had agreed in late 2019 to transit 65 bcm of gas via Ukraine in 2020 and 40 bcm/year in the 2021-2024 period, well down the circa 100 bcm reached in 2017.

28 Naftogaz pointed to the reduced spot gas deliveries, the limitations in refilling its own storage facilities and the ceasing of sales through Gazprom's electronic sales platform aimed at creating an artificial deficit of gas to pressure the EU into securing the rapid commissioning of the Nord Stream 2 pipeline without complying with European rules.

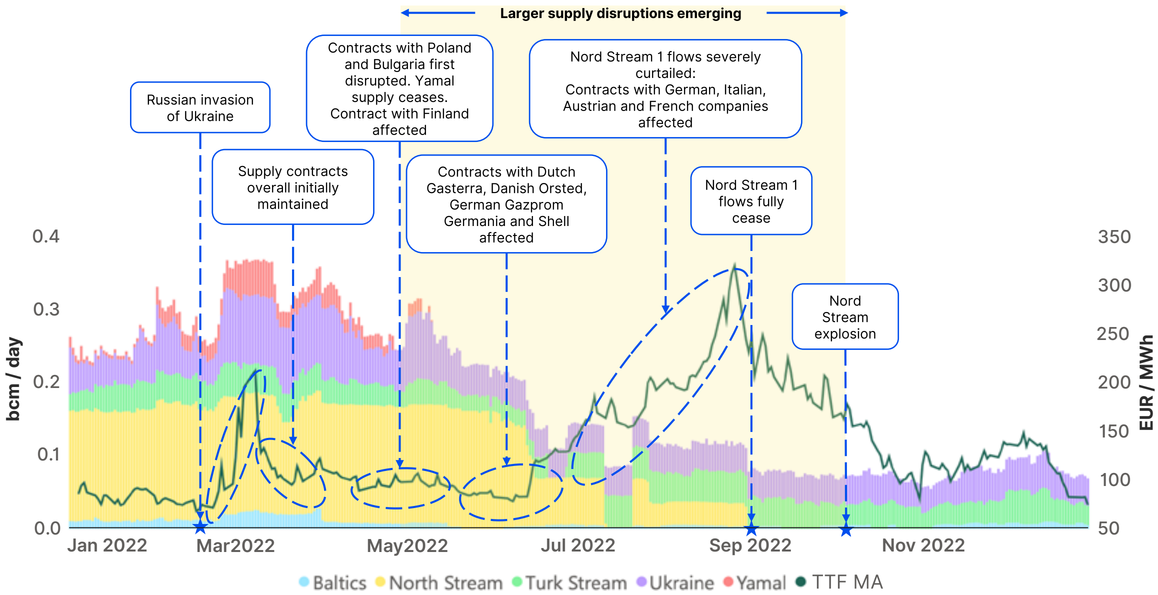
29 The European Climate Law writes into law the goal set out in the European Green Deal for Europe to become climate-neutral by 2050. The law sets the intermediate target of reducing net greenhouse gas emissions by at least 55% by 2030, compared to 1990 levels.

30 Including the Renewable Energy Directive.

- Finally, **the reduced injections in Russian controlled underground storage sites** were a case in point. The low stock levels of EU UGS facilities under the ownership or contractual control of Gazprom were the key driver behind the lower-than-usual storage stocks before winter 2021/2022 in markets such as Germany, Austria and the Netherlands[31], where Gazprom owned large storage sites. Section 2.3. further elaborates on the subject.

29 These tensions and disputes further escalated during 2022 and critically after the Russian invasion of Ukraine on 24 February 2022. The invasion led to the deterioration of the diplomatic relations between the EU and Russia, and the implementation of economic sanctions, while Russia made attempts to use gas supply continuity as an element of political and economic pressure. Figure 22 correlates Russian flows and TTF day-ahead price evolution, with a more detailed zoom-in on events occurring during the spring and summer of 2022.

Figure 22: Overview of aggregated Russian supply into the EU (bcm/day) and evolution of TTF front-month prices (EUR/MWh) – January 2022 – December 2022



Source: ACER based on Platts and ENTSOG TP.

- At the end of February 2022 and the beginning of March 2022, there was a significant price shock in the European gas market due to the Russian invasion of Ukraine. TTF front-month prices surged from 71 EUR/MWh on 21 February 2022 to 212 EUR/MWh on 8 March 2022, reflecting the heightened supply uncertainty due to the military situation.

- Prices partially receded from the second week of March 2022, stabilizing around 95 to 105 EUR/MWh. During this period, Gazprom initially maintained its long-term supply commitments, resulting in total gas flows to Europe ranging from 250 to 340 mcm/day almost until the end of April 2022. However, these flows were 25% lower than in the corresponding period in 2021.

- Supply disruptions gradually emerged from end- April 2022, raising concerns about the reliability and stability of Russian gas imports in the future. Russian gas flows to Poland (10.2 bcm/year) and Bulgaria (3 bcm/year) were first curtailed on 27 April 2022, under the pretext of payment issues related to contracts denominated in roubles. In mid-May 2022, all gas flows through the Yamal pipeline, which still supplied minor deliveries to Germany, came to a complete halt due to Russian-imposed sanctions on the pipeline operator. Additionally, Poland made the decision to terminate its supply contract with Gazprom, which was scheduled to expire at the end of 2022. On 20 May 2022, deliveries to Finnish Gasum (3 bcm/year) were also interrupted due to similar payment concerns. Furthermore, during the first half of June 2022, Gazprom ceased supply to Dutch Gasterra (2 bcm/year, the contract to expire in October 2022). Moreover, Denmark's Orsted (2 bcm/year), Gazprom Germania and its subsidiaries, Shell Energy, and various other gas companies saw their contracts suspended in early June 2022 amid the refusal to pay in roubles and implemented import bans, while Estonia and Lithuania, which bought

31 At the end of October 2021, Gazprom storage stocks were at an unprecedented low level of 25%, which was three times lower than the average of the rest of the EU facilities.

Russian gas on short-term arrangements, also banned Russian imports[32]. Prior to these disruptions, gas flows through the Sokhranivka interconnection point in Ukraine, which was partly used for transiting gas to Europe, had already been halted since May 2022 due to the occupation of Ukrainian territories by Russia. This situation required a system reconfiguration by the Ukrainian TSO and resulted in partial decreases in gas flows into the EU[33].

- On 14 June 2022, Gazprom significantly reduced gas flows to Germany via Nord Stream 1, citing technical problems with the compression equipment and impediments related to sanctions that hindered repairs. Consequently, there was a substantial drop in gas flows to Germany, Italy, France, and Austria that impacted major gas incumbents[34] with corridor flows decreasing by circa 60%, to reach only 40% of their nominal capacity. This situation led to a rapid 40 EUR/MWh increase in TTF day-ahead prices in two days, as Russia also hinted at the possibility of a complete suspension of the subsea interconnector due to repair difficulties.

- The situation continued to deteriorate thereafter. Nord Stream 1 flows gradually declined and first completely ceased on 11 July 2022, allegedly due to maintenance reasons, with no resumption of flows after 2 September 2022 as planned. Prices continuously rose throughout the summer due to the need to replenish storage stocks with expensive LNG while the discontinuation of Russian flows coincided with the other market factors and infrastructure constraints analysed in Chapter 2. Moreover, heavy delayed maintenance in several Norwegian production fields throughout end-August and September also contributed to the price pressure[35]. TTF day-ahead prices reached their peak on 26 August 2022, exceeding 300 EUR/MWh.

- On 26 September 2022, an explosion damaged both the Nord Stream 1 and Nord Stream 2 pipelines, putting a definitive cessation of flows across these interconnectors for the upcoming winter and for an uncertain period. TTF day-ahead prices rose by circa 30 EUR/MWh in the following two days, although they receded again due to an overall lack of consideration by the market for supplies through the interconnector.

30 Overall, during the focus period of this analysis, summer 2022, Russian supply drops were closely correlated with increases in EU gas hub prices[36], as concerns grew about the availability of sufficient gas flows to meet demand and replenish gas storages ahead of the winter season. Monthly average prices on TTF in 2022 stood at over 130 EUR/MWh, more than seven times higher than the average between 2016 and 2021. From March 2022 to October 2022, during storage filling season, prices averaged 160 EUR/MWh.

2.1.3. Adaptative response: reducing dependency on Russian supply

31 The disruption in Russian gas supplies triggered a series of market reactions and adaptive policy responses that are reshaping the EU gas market. To offset the interruption in Russian gas deliveries, the EU had to swiftly source additional gas from alternative supply sources, as well as limit its final gas consumption and promote renewable gas and renewable electricity generation. Moreover, the technical operation of the gas system had to shift to increase gas flows in the west to east direction. To do so, new infrastructure investments were necessary, both to attract increasing EU LNG imports and to deal with supply bottlenecks.

32 Latvia, with a 1.4 bcm long-term contract until 2030 also banned imports from Russia since 2023.

33 In May 2022, due to Russian armed forces controlling the region, the Ukrainian TSO declared force majeure at the Sokhranivka entry point. Consequently, Gazprom was requested to increase gas flow through the alternative Sudzha point. However, Gazprom refused and subsequently reduced transit payments to Naftogaz, the intermediary between Gazprom and the TSO. In response, Naftogaz initiated a new arbitration case against Gazprom. The arbitration case holds significant implications beyond its impact on transit payments to Ukraine. It has the potential to prompt the Russian authorities to sanction the Ukrainian TSO, which could result in Gazprom completely halting gas flows at any given time. Furthermore, the arbitration case may also complicate negotiations for a new supply contract, which must be finalized before the end of 2024.

34 The aggregated volumes contracted by German companies like RWE, Shell Energy Europe, Uniper and others totalling around 35 bcm. Italian ENI has a contract of up to 22 bcm until 2025, while French Engie has a 13.5 bcm contract that has been also suspended since September 2022. As stated by OIES, the majority of these volumes now being the subject of arbitration proceedings (see footnote 18).

35 Maintenance reduced capacity at 13 fields and processing plants throughout end August and September 2022, with lost volumes peaking at 154.68 mcm per day on Sept. 7, according to Gassco data.

36 Front-month hub contracts and spot hub contracts' prices strongly converged during the summer of 2022, while hub contracts with longer maturities also saw significant price increases, especially for the winter 2022/2023 delivery months. See also Figure 3.

32 Early in May 2022, the EC sanctioned its REPowerEU flagship plan[37], earmarking the measures aimed at making Europe independent from Russian gas supplies. The REPowerEU plan assessed the potential contribution for each measure, and, also importantly, allocated financial support to implement them effectively[38]:

- The REPowerEU plan combined short- and medium-term measures to enhance gas supply diversification, energy efficiency and renewable deployment. REPowerEU's key target was to fully offset Russian gas imports by 2027 (mid-term), whilst reducing already Russian gas supplies by two-thirds by the end of 2022 (i.e., from 155 bcm in 2021 to 53.5 bcm in 2022). The largest contribution was given to sourcing additional LNG imports, which should rise by more than 50 bcm year on year. Despite some initial hesitations from stakeholders and academia about the feasibility of the plan, the overall ambition proved by and large right eventually. The EU managed to raise its LNG imports by 72% in 2022 relative to 2021, up to 130 bcm, by means of attracting most of the incremental global LNG production as Section 2.4. discusses.

- The REPowerEU plan marked down many of the key measures to shift away from Russian gas, which were further developed by the EU Council into emergency regulations across the year. The effects of some of these regulations are further analysed across the different sections of this chapter and relate to aspects such as:

    a. Measures aimed at ensuring that sufficient underground storage stocks would be met ahead of winter[39].

    b. Measures related to gas demand savings and energy efficiency with coordinated Union-wide demand-reduction plans and flow solidarity in case of gas supply disruption[40].

    c. Measures related to electricity energy savings and energy efficiency, also introducing a cap on electricity market revenues to renewable generators as well as other retail-related final support measures[41] and measures aimed at accelerating the deployment of renewable energy including biomethane[42].

    d. Common purchases of gas, LNG and hydrogen via the EU Energy Platform for all Member States, as well as new energy partnerships with reliable suppliers[43] and eventually a market correction mechanism setting a bidding limit to EU gas import prices[44].

33 The adaptive response of EU Member States and gas sector stakeholders was progressive, given the inertia and complexities of the gas market and the timing established in the emergency regulations. Some of the so-called emergency measures arguably took quite some time to materialize. While stakeholders' opinions can differ, if possible, they should have been faster to prevent some disturbances (this overall consideration is subject to discussion, e.g., the suitability of the MCM Regulation is still attracting opposing views in the sector).

34 Other adaptive measures, though not labelled as emergency ones, such as the rapid development of new LNG infrastructure to enhance the ability to attract new LNG supply were overall very effective, even if they entail high costs.

37 REPowerEU: affordable, secure and sustainable energy for Europe issued on 18 May 2022.

38 In accordance with the plan, additional investments of 210 billion euros are needed between mid- 2022 and 2027 to phase out Russian fossil fuel imports.

39 Council REGULATION (EU) 2022/1032 of 29 June 2022 with regard to gas storage.

40 Council REGULATION (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas.

41 Council REGULATION (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

42 Council REGULATION (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy.

43 Council REGULATION (EU) 2022/2576 of 19 December 2022 on enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders.

44 Council REGULATION (EU) (EU) 2022/2578 of 22 December 2022 establishing a market correction mechanism to protect Union citizens and the economy against excessively high prices.

2.1.4. Lessons learnt: diversify supply and review the efficiency of market interventions

35 EU's over-reliance on its historical major gas supplier, Russia, was harshly exposed by the magnitude of the supply shock, which had dramatic impacts on EU energy prices. Despite some prior efforts by the EC, Member States, National regulatory authorities[45] (NRAs), TSOs and market participants to diversify gas supply through policies, new contracts and infrastructure investments, these attempts proved clearly insufficient. This misjudgement of relying heavily on Russian gas supply extends beyond the design of the gas market and has geopolitical implications. Further supply diversification would have mitigated the impacts of the Russian supply shock, but this was not the market reality in 2022. Consequently, diversification had to be done speedily resulting in notably higher costs.

36 In response to the Russian supply shock, the market gradually restored equilibrium during the summer of 2022. This process brought losses and opportunities for gas producers, suppliers, and traders within and outside the EU. While several companies reported significant profits in 2022[46], some utilities faced difficulties in continuing their activity[47]. Meanwhile, gas-intensive industrial manufacturers and households faced on average higher procurement costs. In various instances, the price rises led to demand destruction and disruptions in industrial plans[48]. Moreover, several bilateral supply contracts between Gazprom and EU gas buyers were cancelled, which then triggered arbitration cases demanding billions of euros from Gazprom in compensation[49].

37 As it will be expanded in Section 2.2., governments diverted vast budget lines to assist final consumers and industries in paying their energy bills as well as allocating substantial loans and bailouts to utilities and traders to meet their liquidity needs. EU countries have allocated 646 billion euros across various direct support and financing programs in accordance with Bruegel[50], equivalent to 4% of their Gross Domestic Product. This outcome continues to have significant impacts on EU economies.

38 Within this reshaped market equilibrium, two important lessons stand out regarding supply. Firstly, and foremost, the need to continue supply diversification to prevent the control of the EU gas supply portfolio by a small group of actors. LNG stands out as a flexible supply source option that should contribute to enhanced supply diversification. However, it is important to address congestion issues to maintain a steady flow of LNG.

39 Secondly, it can be argued that the radical price rises registered during the peak price periods, like in mid-August 2022 when prices steadily surpassed 200 EUR/MWh, were unable to attract large additional supplies in a tightening global market. Those price signals exerted a stronger influence on the demand side, leading to the reduction of the consumed volumes and prioritizing gas allocation to buyers with stronger financial capabilities to secure limited supply options.

40 Therefore, it is crucial to review specific market interventions to enhance their efficiency[51]. Some measures may have unintentionally added price pressure, distorting demand and supply dynamics. Certain forms of public support could have been excessive or misdirected, leading to limited demand response and further straining prices. The forthcoming Section 2 will delve deeper into these considerations.

41 On a positive note, the market design and a coordinated system management in Europe, emphasizing

45 The ACER Gas Target Model aims at diversifying gas supplies, with at least 3 different supply origins available at each MS to enhance security of supply and price competition. The target was first met in 2019.

46 See for example Greenpeace overview assessing the evolution of the annual balance sheets of global oil and gas majors. In accordance to Greenpeace, shareholders of the world's top five oil and gas companies saw record profits of EUR 192 billion and distributed EUR 93 billion in the form of dividends and share-buy-backs in 2022, roughly twice above 2021 figures. Various Asian LNG suppliers and global LNG portfolio aggregators managed to capture incremental margins from global arbitrage opportunities. Yet, for the case of the suppliers and traders that sold gas at very favourable prices during summer 2022, it can be argued that they had also incurred in some risks when hedging their positions, which could have resulted in losses in a totally different price scenario.

47 See for example considerations about Germany's local utilities in this Euractiv article.

48 See Section 2.2.3, including references to industrial gas consumers that reported curtailment and/or relocation of their production.

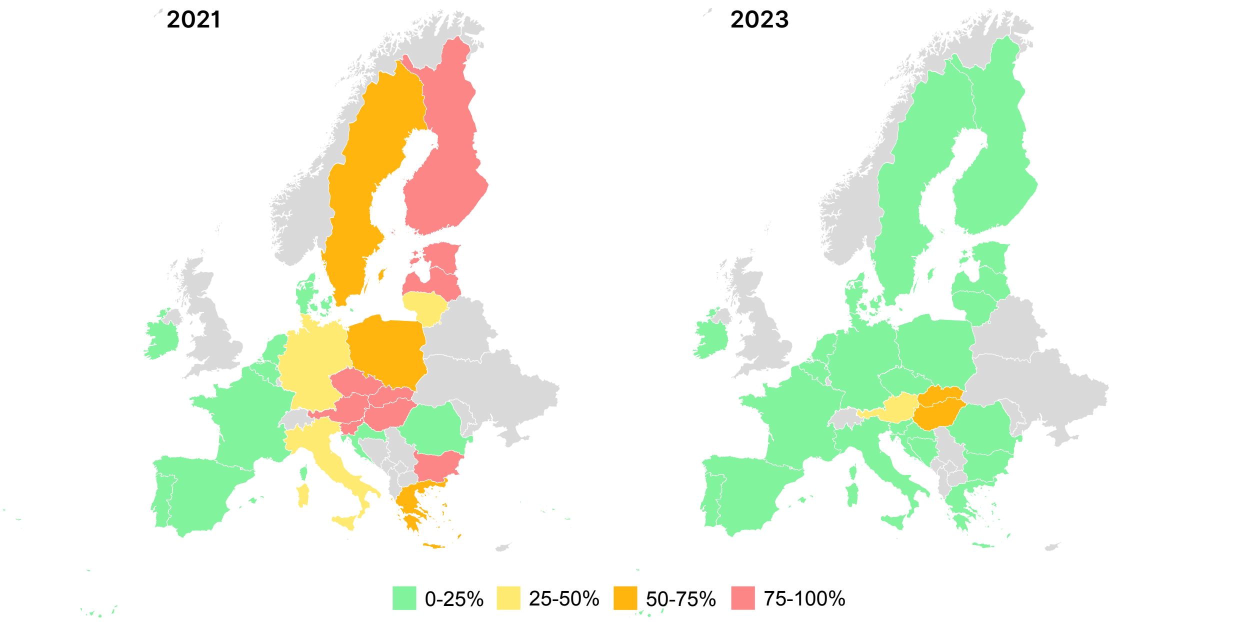
49 Uniper for example has launched an arbitration process to get compensated over the undelivered gas volumes claiming for 11.6 bn euros. ENI, RWE or ENGIE are also in arbitration processes for same reasons.

50 See Bruegel fiscal tracker overview related to the budget earmarked to shield households and firms from the energy crisis.

51 Similar assessments about the efficiency of emergency measures are relevant for the electricity market. ACER and CEER exposed their position on the matter in their response to the EC Public Consultation for the Electricity Market Design. Specifically, pages 17 and 18 refer to the range of options to limit infra-marginal revenue in case of sustained high prices, which in ACER and CEER's view should be limited only to extreme situations.

hub integration, played a crucial role in attracting and distributing alternative gas supplies. The reforms aimed at bolstering market integration and fostering competition within the interconnected European gas system were instrumental in adapting to the new scenario and reducing the reliance on Russian supply, as Figure 23 analyses. Therefore, sustaining these reforms is vital to ensure continued effectiveness and resilience in the face of evolving energy landscapes. Furthermore, the EU is expected to become more resilient after this crisis by improving its domestic energy production via renewable capacity additions.

Figure 23: Estimated share of Russian gas supplies in terms of the contractual origin of gas in EU MSs (% of actual volumes purchased) – 2021 vs first semester 2023



Source: ACER estimations based on ENTSOG TP, Eurostat and Platts data. See Figure 20 notes for detailed considerations per MS.

2.2. Driver 2: Demand developments

2.2.1. Driver relevance: demand response key in price formation

42 As it was highlighted in Section 2.1.1, price formation is a function of the interaction between the supply and demand elements of the market. In turn, the evolution of gas demand across the EU is determined by a combination of components, including final consumption by households and small-medium enterprises, gas consumption by energy-intensive industries and by manufacturers that use gas as feedstock (e.g., chemical industry, fertilisers), gas use in transport or agriculture and gas consumption for power generation. In addition, gas procurement to inject gas in underground storages, which typically occurs during the summer season to replenish stocks ahead of winter, also adds to demand and hence impacts prices.

43 While there are national differences per Member State[52], at the EU level, industrial gas consumption for energy input and feedstock accounts for 25% to 30% of final demand[53]. Households, the public sector and small to medium-sized enterprises account for 35% to 40% of final consumption across the year, although they are highly seasonal in their consumption patterns as their demand is heavily affected by weather. Gas demand for power generation, together with some uses like transport and agriculture account for the remainder.

44 The seasonal nature of households' demand results in pronounced fluctuations in final gas consumption. Usually, two-thirds of total EU final consumption is registered from October to end-March. The remaining third part occurs in the summer season. This is despite milder winters and warmer summers[54]

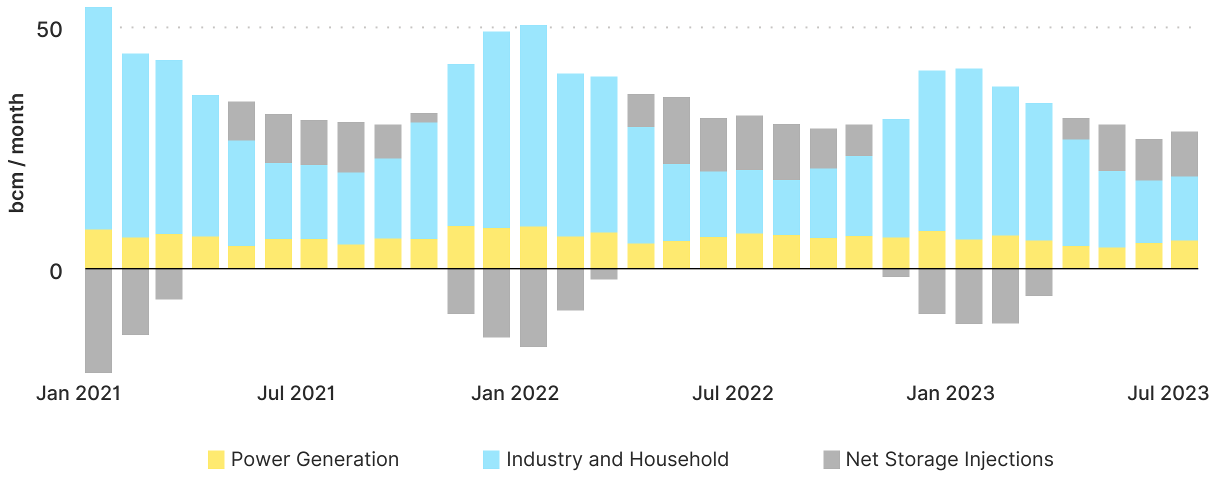
52 The breakdown of demand distribution per sector can vary significantly per Member State, depending on the presence of industrial intensive industry, weather patterns and the role of gas-fired power plants in meeting power consumption.

53 The exact percentage is dependent on various caveats and on data availability and hence is not straightforward to straighten out. For example, the chemical industry is assessed to consume more than one third of its gas as feedstock and the rest as energy input.

54 Warmer summers would rise gas-fired power generation needs for cooling purposes.

contributing to flattening the gas demand curve to some degree in recent years. Conversely, gas storage injections contribute to levelling the combined gas procurement curve, as they are highly seasonal too; during summer months, storage injections account for additional gas procurement that can represent up to 40% of final consumption, as Figure 24 shows (i.e., 40% of the sum of industrial, households, and power-generators final gas consumption[55]).

Figure 24: Overview of EU gas consumption per sector plus net storage injections (bcm/month) – January 2021 – July 2023



Source: ACER estimations based on Eurostat data and ENTSO-E TP.

45 A crucial aspect in determining the relation between demand and prices refers to the concept of demand elasticity, which measures the degree of response of demand to prices. Demand elasticity can be affected by various factors such as the availability of substitutes, economic growth, income levels, price hedging strategies and relevant regulations.

46 Gas demand has traditionally been rather inelastic in the short term. Under the moderate price levels of recent years, changes in prices tended not to significantly impact the final volume of gas consumed. This was primarily due to the prevalent use of natural gas for essential purposes like heating, industrial processes, and electricity generation, with limited short-term alternatives available. Consequently, transitioning to alternative fuels or implementing short-term consumption reduction measures may not be straightforward or cost-effective. However, in the mid- to long-term, gas demand can be more elastic, particularly if the price incentive is high and maintained over time. Then consumers may be able to switch to alternative fuels or reduce their consumption by implementing efficiency measures.

47 Different gas demand sectors can react differently to price changes:

- Overall, household gas consumption tends to be the least price elastic due to structural needs. However, if the price signal becomes sufficiently high, consumption gradually adjusts to a certain level.

- Industrial gas consumption is generally more elastic than household consumption, visibly in the short term[56]. Yet, industries' gas demand elasticity is influenced by the price-responsiveness of the final goods they produce. This means, the resilience in the consumption of the final goods that the industry produces in the face of gas price fluctuations directly affects industrial production. Other factors such as the degree of competition in the end-product market (i.e., less competition tends to result in less price elasticity), the energy efficiency investment costs and the presence of alternative fuels to meet the energy intake or the use provided by gas also impact price elasticity (e.g., when gas is used as a feedstock, there tends to be little to no fuel alternatives, making gas demand more inelastic to price changes).

55 Once withdrawn, those storage stocks built up in summer will account for 20% to 25% of the supply delivered in winter months.

56 For example, a recent study focused on Germany (Natural gas savings in Germany during the 2022 energy crisis, published in Nature energy) identified that German industry started to reduce gas consumption earlier than households did when prices commenced to increase at the end of 2021. The study showed that German industrial demand fell 4% year on year in September 2021, and steadily dropped since as prices kept rising, to reach a 27% fall year on year across autumn and winter 2022. In contrast, households' gas savings were more modest and took more time to materialise.

- Demand for gas in the power sector is overall the most flexible, up to a certain level. On the one hand, gas prices relative to combined coal prices and carbon emission costs lead to switches between the two power-production technologies. On the other hand, the variable availability of renewable generation and the actual level of electricity demand shape the final dispatching of gas-fired power plants.

- Storage-related gas procurement is also relatively elastic, although up to a certain limit. Stocks need to be replenished to sufficient levels ahead of winter when the heating demand peaks. The evolution of winter to summer price spreads is a key driver for storage injections, as Section 2.3.1 discusses.

- The section that follows analyses the demand elasticity developments during the summer of 2022, amid the unprecedented price levels accelerating some demand reduction dynamics.

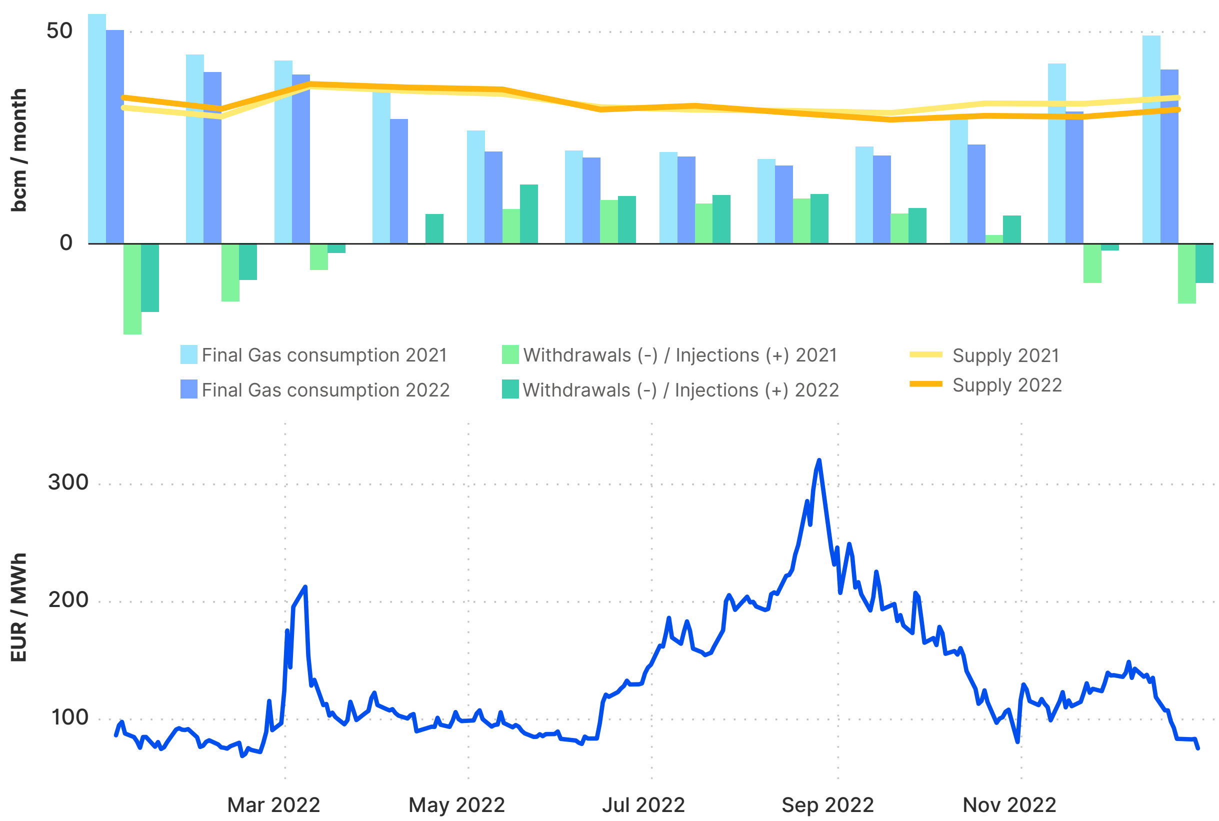
48 The section that follows analyses these demand elasticity developments during the summer of 2022, amid the unprecedented price levels accelerating some demand reduction dynamics.

2.2.2. Overview of summer 2022: resilient EU demand contributed to clear prices up

49 As stated, the extreme price rises witnessed during the spring and summer of 2022 must be attributed primarily to the Russian supply shock. However, it was the relatively resilient demand for gas competing for the remaining supply that contributed to prices clearing at record high levels.

50 Figure 25 provides a closer look at the evolution of aggregated final gas consumption plus storage injections (withdrawals in the winter season) in the EU in 2021 and 2022, and their correlation with TTF front-month prices for the year 2022. Complementarily, the figure shows the reduction in EU daily supply throughout the year 2022 in comparison to the year 2021.

Figure 25: Overview of EU final consumption, storage injections/withdrawals and external EU monthly supply (bcm/month) relative to TTF front-month prices in 2022 (EUR/MWh)

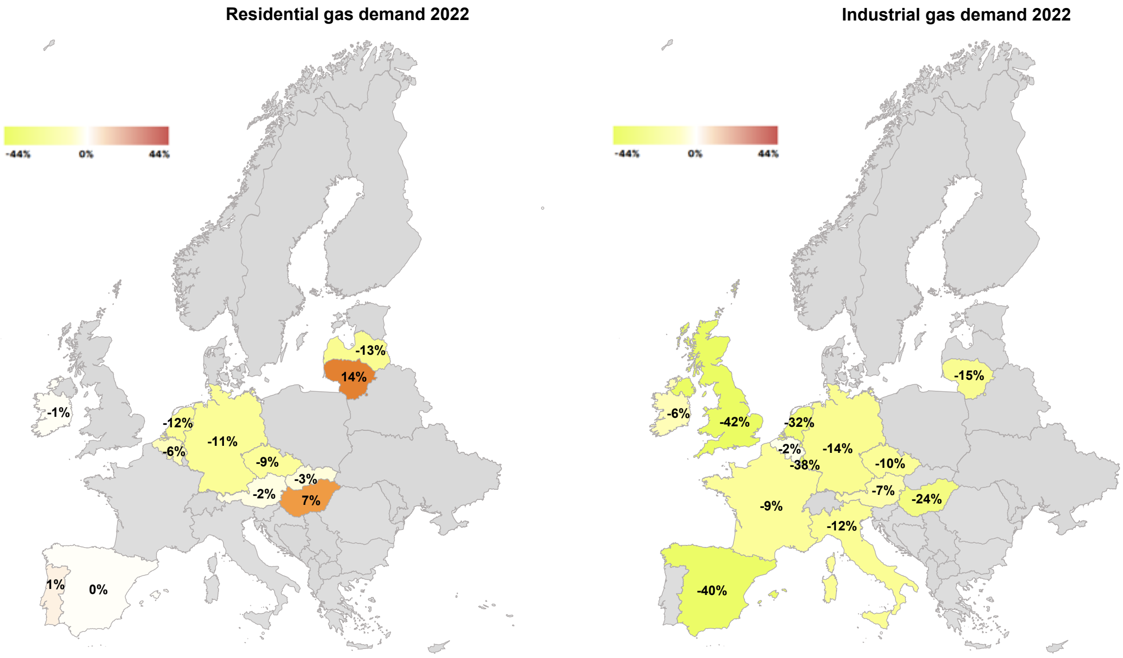


Source: ACER calculations based on ENTSOG TP, GIE, Platts.

51 The decline in EU total gas supplies in 2022 relative to the year 2021, which as shown in Figure 25 intensified since the end of May 2022, was primarily caused by the curtailment in Russian pipeline imports. To balance these reduced flows and continue to meet final demand - sustained up by rising storage injections -, the EU increasingly relied on costly spot LNG imports. That caused a rise in marginal prices at EU gas hubs. Yet, the reduced supply options and the elevated hub price levels began to stimulate reductions in final consumption.

52 As shown in Figure 29, final gas consumption decreased by more than 50 bcm across the EU in 2022 eventually, a 14% year-on-year drop. Figure 26 complements the assessment, showing the demand changes for the residential and industrial sectors in 2022 for a sample of Member States where data was accessible. The figure relates to the analyses shown in Figure 7 in Chapter 1, the latter for the year 2023, and helps to illustrate how gas demand in the residential sector dropped less than in the industrial sector[57].

Figure 26: Residential and industrial gas demand changes (%) for selected Member States in 2022 in comparison to 2018 – 2019 average



Source: VaasaETT 2023.

53 European gas demand statistics tracked by Bruegel reveal that household consumers started to somehow respond to the price rises from spring 2022. However, the core of households' gas savings occurred in winter 2022/2023, led by gradually increasing supply costs reaching their supply contracts, the seasonality in heating demand (larger consumed volumes resulting in larger expenditure) and the enhanced public attention for the need to save energy. EU household gas consumption dropped by 18% on average across winter 2022/2023 eventually, although a significant part of the drop must be attributed to the milder temperatures.

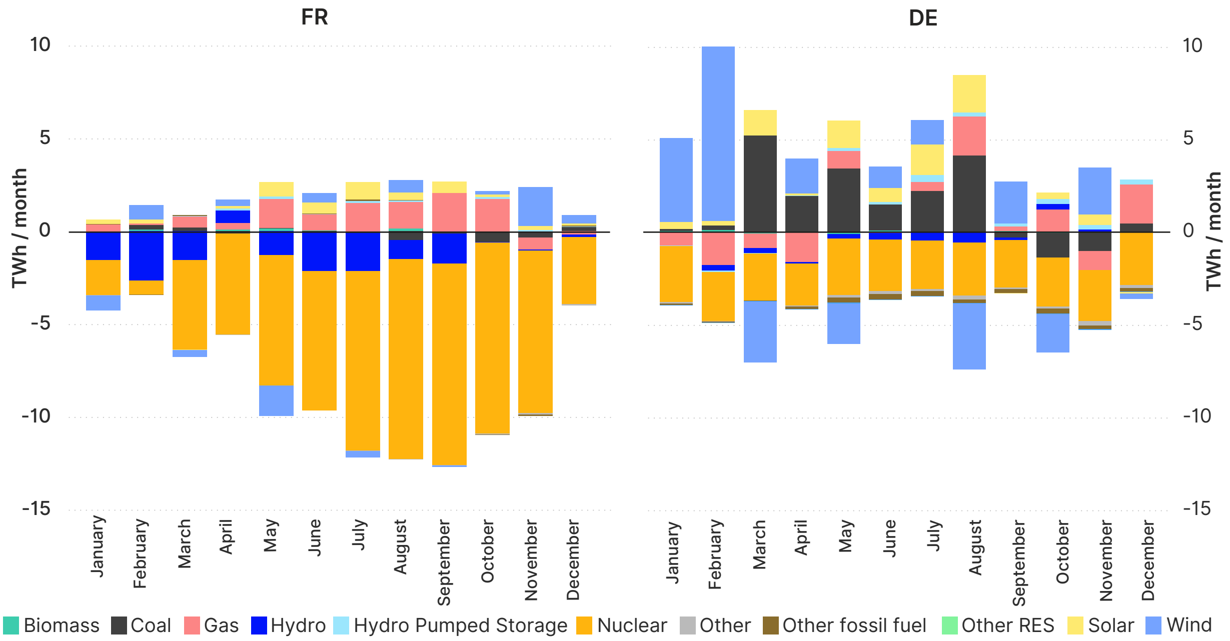
54 On average, the EU industrial sector witnessed a very significant decrease in gas demand, albeit varying based on contractual and case-specific factors. In certain instances, price hedging managed to partially protect specific manufacturers from the most immediate increases in hub prices. Additionally, the ability to adjust production or to temporarily halt operations relying on produced goods' stocks or alternative supply chains contributed to maintaining the business cases. Overall, the prevailing client commitments, the consumption-resilience of the produced goods in the face of gas price fluctuations and, last but not least, the adoption of efficiency measures all influenced the gas demand trends within specific industries. Generally, certain time lags (i.e., of a couple of months) were frequently witnessed between the initial price rises and the subsequent demand reduction, as industries adapted to the new scenarios. However, as the International Federation of Industrial Energy Consumers (IFIEC) underlines, it is noteworthy that industrial demand destruction remained consistent when price levels exceeded 100

57 E.g., although demand decreases were generally registered, several Member States either stayed at the same level or increased their energy demand level during 2022.

EUR/MWh from March 2022, especially in industrial sectors where gas procurement heavily relies on spot products. These sectors, particularly ammonia but also to a rising extent acetylene production, are characterized by a higher degree of commoditisation and are further influenced by the fact that the final products are part of globally interconnected, competitive, and financially exposed markets[58].

55 A deteriorating power generation situation during the summer of 2022 added to the strain on gas demand. This can be attributed to various factors, including a shortage of nuclear power in France and depleted hydroelectric reserves in multiple Member States due to reduced precipitation levels during the spring and summer months. There were also sourcing constraints in some coal plants, due to reduced water levels at waterways hindering coal transport across North-West Europe (particularly in Germany). Moreover, coal plant closures coupled with periods of reduced renewable output due to lack of wind and extreme heat led to a lessened generation capacity availability. The interplay of power capacity constraints, gas plants competing with coal and hydro to set power marginal prices and hedging aspects[59] prompted a rise in power prices relatively higher than the rise in gas prices, which made gas-fired power generators' margins very high. That caused a further surge in gas consumption for power generation in various Member States. Those rises in consumption in turn further contributed to putting upward pressure on short-term gas prices, particularly across summer 2022. Figure 27 offers an overview of gas-fired generation in contrast to other power generation technologies in France and Germany, taken as an example to illustrate the trends (Figure 8 in Chapter 1 shows a similar analysis for the EU until August 2023).

Figure 27: Overview of monthly power generation changes by production technology in France and Germany (TWh/month) – 2021 vs 2022



Source: Acer calculation based on ENTSO-E TP data.

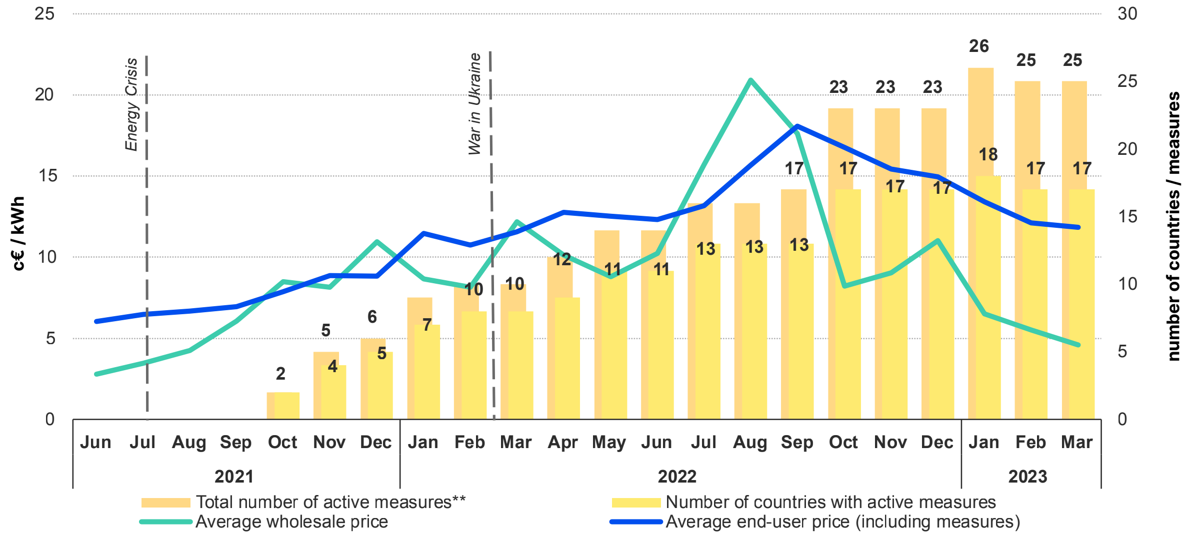
56 Finally, the financial support provided by governments to households and industries to mitigate the impact of the crisis also influenced demand dynamics. Member States had to swiftly respond to complex issues during the crisis and in a very pressing economic environment, sometimes arguably lacking a comprehensive overview of potential short- and long-term implications of the choices made. Figure 28 tracks the adoption of retail price interventions for residential consumers across European gas markets from June 2021 to March 2023[60].

58 E.g., as of October 2022, about 70% of European ammonia production capacity had been reduced or shut down as ammonia market is produced and traded around the world, as this IEA Report discusses.

59 It is understood that gas procurement for power-generation more highly relies on shorter-term products, given the uneven CCGTS' generation profile, which is increasingly impacted by renewable generation availability. Yet, gas-fired power generators can also hedge part of their gas procurement, particularly if their power production serves bilateral more-stable power contracts.

60 For more on this see the ACER CEER Energy Retail and Consumer protection 2023 Market Monitoring Report.

Figure 28: Adoption of retail price interventions for typical residential consumers across EU Member States[61] (total number of measures) and average TTF day-ahead price evolution (EURcent/kWh) – June 2021 - March 2023



Source: VaasaETT 2023.

*Note: **Multiple measures can apply to the same retail price intervention category (i.e., energy component-related subsidy or price cap, energy tax cut, network fee cut or VAT reduction).*

57 Public support was critically necessary to maintain economic activity and prevent further social damage. However, some of the broad and non-targeted emergency measures aiming at reducing energy prices for all, such as lowering taxes and levies on energy final consumption, hindered incentives for stronger demand response, moving in turn the relative level of clearing prices somewhat up. Part of that public financial contribution could have been transferred indirectly to EU suppliers and non-EU producers, via some higher wholesale procurement and prices. ACER issued a specific report analysing the emergency measures implemented during the year 2022 and their contribution to the achievement of regulatory goals[62]. In accordance with this analysis, few measures targeted specifically energy transition, including demand response or market integration. The effect of emergency measures on these two regulatory goals was mostly neutral to potentially negative.

2.2.3. Adaptive response: the EU demand shift will entail lasting implications

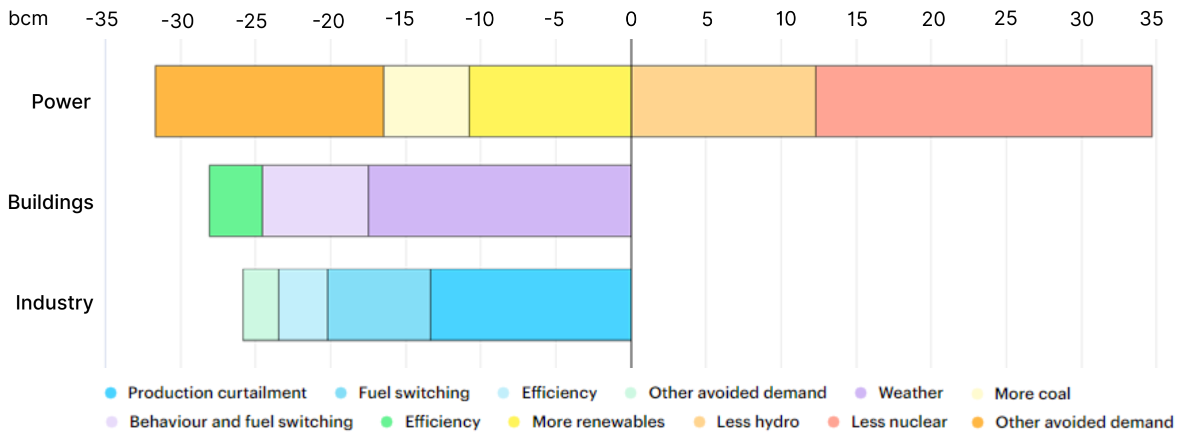
58 The unprecedented 2022 market conditions prompted a demand shift that will have lasting implications for the EU gas market. The International Energy Agency (IEA) has assessed the contributions of different demand sectors to the total 14% decline in gas demand in 2022 compared to 2021[63]. This historic demand drop, amounting to more than 50 bcm, resulted from a combination of factors including reduced economic activity, decreased industrial production, milder weather conditions, increased efficiency investments and behavioural changes, as shown in Figure 29.

61 The data compiled for the analysis only consider 20 Member States that have adopted at least one measure during the energy crisis.

62 See footnote 3.

63 See IEA commentary Europe's energy crisis: What factors drove the record fall in natural gas demand in 2022.

Figure 29: Estimated drivers of change in natural gas demand in power, buildings, and industry in the European Union (bcm) - 2021 vs 2022



Source: International Energy Agency.

59 As analysed in Chapter 1, the relative drop in gas demand has been maintained in the first half of 2023, reaching approximately 11% relative to 2022[64]. Even if the more modest price levels seen in 2023 have started to partly restore some higher industrial activity, a substantial part of the demand drops triggered in 2022 are becoming permanent due to the efficiency investments made, fuel substitution (e.g., electrification and renewable energy development), and the solidified behavioural changes.

60 The crucial role that demand should play in limiting price surges was clear to the sector and policymakers. In May 2022, the EC published the EU Save Energy strategy[65] in conjunction with the REPowerEU plan. To further enforce demand reduction, the EC published in July 2022 a European Gas Demand Reduction Plan, to coordinate the implementation of demand-reduction measures[66]. Its linked regulation[67] mandated Member States to use their best efforts for at least a 15% reduction in their gas consumption from 1 August 2022 to 31 March 2023, compared to the average gas consumption in the same period over the previous five years[68]. Many measures, including financial support for efficiency investments, public attention campaigns, public transport discounts, and lower heating temperatures in public buildings were introduced in different Member States[69]. The average EU gas demand savings in the defined period between August 2022 and March 2023 reached 17.7%, with the most significant relative reductions occurring in October and November 2022[70]. However, there were significant differences among Member States. Finland achieved the highest percentage of savings, while countries like Ireland or Slovakia, fell short of the target for different reasons such as less winter related consumption, less gas-intensive industries or rising consumption of gas for power generation.

61 As referred, a portion of the adaptive demand reduction observed in 2022 and the first half of 2023 will transition into permanent structural demand destruction. This is a result of the implemented efficiency measures but also certain business decisions that will maintain gas demand below previous levels[71]. In addition, the increasing addition of wind and solar power generation is expected to gradually erode the market share of gas-fired power generation. Furthermore, housing retrofits, heating electrification, and efforts to encourage gas savings will contribute to reduced household consumption in the medium term. Although decarbonised gases will partially replace conventional natural gas, a drop of 30% or more in natural gas demand by the end of the decade appears plausible.

64 As discussed, the big bulk of EU's demand reduction in 2022 occurred in the second half of the year.

65 See EC communication EU Save Energy. The strategy aimed to achieve immediate energy savings through voluntary measures, while concurrently accelerating and strengthening more structural energy efficiency measures in the medium term.

66 The Save gas for a Safe Winter plan included guidelines on the measure that Member States could opt to take in. The measures included promoting fuel switching, tender systems by which Member States incentivise a reduction of consumption by large consumers, contractual swaps to re-allocate industries production, interruptible contracts, awareness raising campaigns and targeted obligations to reduce heating and cooling.

67 See footnote 40.

68 This agreement was subsequently extended in March 2023 for an additional year.

69 In March 2023 ACER published an inventory of 400+ measures adopted by Member States to cope with the energy crisis.

70 See for example an overview by Argus based on Eurostat statistics.

71 E.g., demand will not recover to previous levels. As an example, one of the key EU industrial gas consumers, BASF, referred that it would to downsize permanently in Europe in view of the high energy costs making the region increasingly uncompetitive.

2.2.4. Lessons learnt: commit to demand reduction and unlock efficiency investments

62 The EU should continue moving towards reducing its consumption of conventional natural gas to decrease its external energy reliance and assist its climate targets. During this transitional period, the less elastic segments of gas demand will hold a significant influence in shaping short-term gas prices. This is because those demand segments match a substantial share of the available supply during price clearing.

63 However, the combined task of steadily reducing gas demand whilst making it more flexible is not straightforward, particularly in more immediate timeframes. As mentioned earlier, natural gas currently serves essential energy needs for households and industries at competitive prices (aside from the extreme price developments of the last two years), whilst it also plays a crucial role in balancing and ensuring the security of supply in the more integrated EU energy system. Furthermore, the significance of gas in the power sector can be expected to be still partly reinforced in this decade as coal plants retire[72], despite the rise of renewable power generation will be offsetting this trend.

64 Moreover, the pace of demand reduction has important implications for infrastructure investments and long-term contracts[73]. Yet, while stable gas demand prospects are essential for bolstering the business cases of new infrastructure projects that alleviate supply congestion in the evolving EU gas system, enforcing gas demand for supporting these infrastructure developments would be inconsistent with reaching the EU decarbonisation targets.

65 Bearing in mind these considerations, it is crucial to uphold Member State commitments for demand reduction and allocate significant budgets to unlock energy efficiency investments, particularly in space heating, and industries. Specific measures to achieve that aim should be based on thorough cost-benefit analyses. As concluded in the ACER Assessment of emergency measures in electricity markets in balancing choices for measures to take during a crisis[74], measures for risk preparedness and energy savings should be prioritised. These are no-regret options. Ideally, public support should be primarily directed towards promoting demand savings and efficiency investments instead of subsidising final supply costs. This approach avoids putting extra upward pressure on prices resulting from higher (subsidised) consumption, which might lead to welfare transfers from Member States' government budgets to external gas producers.

66 Complementarily, governments need to reconsider how to manage public spending on emergency measures and ensure swift mobilisation should a crisis of such magnitude reappear. Trade-offs inevitably emerge among measures designed to address affordability, security of supply, efficiency, and energy transition. Member States must prudently assess the costs, objectives, and consequences of the measures they choose to implement. The continuation of non-targeted support may ultimately drive inflation up, thus adding to the negative impacts of the crisis[75].

67 Finally, promoting price hedging strategies is another aspect that could contribute to reducing price pressure during specific periods. However, market participants need to strike their own preferred balance between the higher flexibility and more dynamic prices for volumes contracted in a shorter term and more stable procurement approaches based on forward trading products or bilateral long-term supply contracts. This balance will be importantly shaped by final clients' price demands. While acknowledging the need to strike a balance, ACER is overall not in favour of EU-wide obligations on suppliers to hedge beyond the volumes and maturities of fixed price contracts that they have with consumers. Member States should be allowed to impose such obligations at the national level if they can find ways to mitigate the risks involved with such an obligation[76].

72 Germany for example plans to add between 17 GW and 25 GW of gas-fired power capacity by 2030.

73 In this context, ACER recommends that any new gas infrastructure critical to addressing the gas supply challenge shall also unambiguously demonstrate quantitatively their contribution to reduce methane, CO2 and other emissions. See ACER Opinion on NDPs-TYNDP consistency 2022.

74 See footnote 3.

75 For example, the European Central Bank (ECB) has referred that government support measures to shield the economy from the impact of high energy prices should be "temporary, targeted and tailored to preserving incentives to consume less energy".

76 See ACER and CEER Reaction to the European Commission's public consultation on electricity market design, published 14 February 2023, 1.1.1 answer 6 and 1.5.3 answer 1.

2.3. Driver 3: Storage analyses

2.3.1. Driver relevance: storage dynamics notably influence price formation

68 Underground storage sites play a crucial role in the EU gas market. They enhance the resilience of the EU gas supply system and contribute to EU gas price stability. Underground storage facilities are key to securing mid-term supply to meet the large seasonal final consumption swings, as well as assist price management, and support a more flexible system operation in the short term. The sites' dimensions and their technical features determine storages' roles and valuation strategies. Some types of storage facilities can be used in a more flexible manner, not only seasonally, than others[77].

Storage-valuation strategies

Traders, gas producers and suppliers use underground storages to manage volume and price risks, adjusting their positions based on market signals. They do that in both short-term (i.e., days, weeks) and mid-term (i.e., months, seasons) timeframes, influencing overall hub price formation. Traditionally, storage users use two storage-valuation strategies:

- **Intrinsic-value** strategies refer to the value gained from the mid-term/seasonal hedging of forward prices. Hedging strategies revolve around the summer-winter seasonal spreads and their relationship with storage utilization costs. The fundamental idea is to acquire less expensive gas in the summer, store it, and subsequently release it during winter months when demand and gas prices are higher.

- **Extrinsic-value** strategies refer to the value gained from short-term flexibility in storage use in response to short-term market developments. This generally applies to managing short-term price volatility, but also the changes in the relative pricing of gas for forward products across the year.

Both strategies are interrelated in practice. Market participants may initially book storage capacity and conclude trades to hedge seasonal spreads and secure supply needs, but then they might arbitrate between those contracts as they cascade, adding profitability from the extrinsic-value positioning to the initial intrinsic positioning.

69 Storage dynamics significantly influence hub price formation. In spring and summer months, storage injections add up to final gas consumption segments in allocating supply and hence impact prices. In turn, in autumn and winter months, the achieved storage filling levels and the withdrawal rates decisively impact hub price formation. Relatively low stock levels entail more limited withdrawals availability going forward, which can contribute to putting upward pressure on prices. Conversely, sufficient storage stocks offer more certainty about the resilience of supply and can contribute to reducing winter prices and smoothing price volatility.

70 As stated, the relation between storages and summer-winter hub products' price spreads is key in determining injection dynamics[78]. Figure 30 offers an overview of the evolution of average summer-winter spreads since 2017 related to net injections in the summer season. As it will be further analysed, the usual association between cheaper summer prices compared to winter prices typically encouraging injections was not maintained in parts of summer 2022. This reversal of the spread was due to the critical need to inject gas into EU storages even in a scenario of negative summer-winter spreads across various summer 2022 months.

77 Salt caverns facilities are the most flexible, while aquifers and hydrocarbon reservoirs tend to be operated in a more seasonal pattern.

78 Past versions of the ACER MMR have discussed the different regulations and dynamics of storage use across Member States. The type of access regimes is a crucial element in storage sites management, specifically in aspects related to tariffs setting and capacity accessing offering. See ACER MMR 2021 Section 1.2.4.2. Overview of storage access regimes and storage significance per Member State.

Figure 30: Evolution of TTF summer-winter hub price spreads (EUR/MWh) related to gross injections into EU gas storages during the summer season and storage stock levels (bcm) - 2017 - 2023

Source: ACER based on GIE and ICIS data.

Note: The summer-winter price spreads are assessed considering two methods; first, the spread 'at the beginning of the injection season' is assessed as the average price difference between season+1 (summer) and season+2 (winter) daily prices traded over the month of March. Second, the spread 'across the injection Season' is assessed as the average price difference between the month-ahead product daily prices and the season+1 (winter) prices as traded during each of the six summer months. TTF prices are used as a general benchmark for the EU. However, while hub prices tend to be well correlated, differences in the spread values can appear at specific hubs.

2.3.2. Overview of Summer 2022: urgent stocks' strengthening

71 As shown in Figure 30, EU underground storages held 27 bcm of gas on 1 April 2022, representing less than 30% of their nominal capacity[79]. This was 10 percentage points below the preceding five-year average level. Although the stored gas levels were not far from those recorded in April 2021 (which were also relatively low) concerns arose about the feasibility of sufficiently replenishing EU gas stocks across summer 2022 in a context of substantially limited Russian pipeline imports. This situation created some anxiety about the resilience of the EU gas supply for the approaching winter 2022/2023, which notably contributed to move hub prices up.

72 The reasons behind the low stored gas volumes at the end of winter 2021/2022 have been extensively discussed[80]. Storage injections during the summer season months of 2021 had been modest due to reduced EU LNG imports, an outcome of strong global LNG competition and various outages that limited LNG production in that period. Moreover, partly lessening pipeline gas inflows and relatively unattractive hub price seasonal signals reduced injections. Furthermore, it was critical that during summer 2021

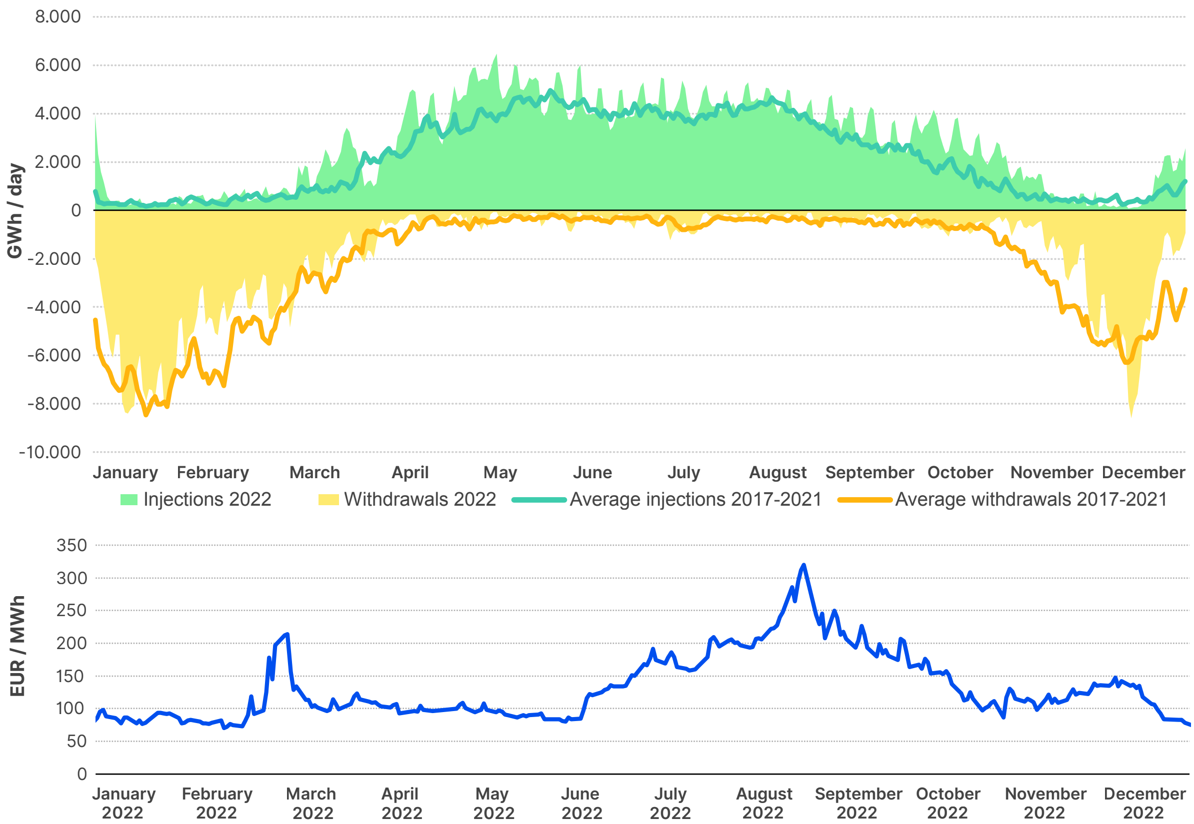
79 On 1 April 2022, EU storage stocks reached 30 bcm. Aggregated EU storage stock capacity amounts to 110 bcm, while the Ukrainian storage sites add an additional 12 bcm.

80 See also ACER MMR 2021 Section 1.2.4.1. Evolution of EU storages utilisation in 2021 and the first half of 2022.

Gazprom did not fill up the storage sites that it owned or controlled in the EU to the levels observed in previous years, despite holding a significant portion of EU storage assets amounting to approximately 12%[81]. That led to EU storage stocks reaching one of the lowest levels ahead of winter in recent years: 73% of nominal capacity for the EU average on 1 October 2021, with 20 bcm less gas stored than in the average of October 2017 to 2020.

73 Gas withdrawals from storage sites during Q1 2022 (see Figure 31) remained below previous years' average, due to mild weather conditions and increasing EU LNG imports. While this helped to partly ease supply tensions, EU storage stocks entered the summer season of 2022 at lower levels than usual.

Figure 31: Overview of EU storage injections and withdrawals across 2022 in comparison to the average of five preceding years (GWh/day) and TTF day-ahead price evolution (EUR/MWh) – 2017-2021 and 2022



Source: ACER based on GIE and ICIS data.

74 During the summer of 2022, there was a pressing need to strengthen storage stock levels to ensure a more resilient gas supply for the upcoming winter. This led to a rapid and substantial injection of gas into storage facilities, driven by both market and, importantly, policy responses. Although the relationship between injected volumes and price evolution was not strictly linear (Figure 31 shows no strong correlation between daily injection levels and TTF day-ahead daily prices in 2022), ACER, following conversations with gas sector associations and traders and also after analysing the trading positions reported to REMIT of those entities more active in storage refilling in those months, understands that the imperative to inject gas into storage facilities played an important role in driving the price increases during summer 2022.

75 Gas storage injections reached record highs in April and May 2022, after most storage capacities were allocated via auctions. Above-average storage injection levels were overall sustained over the entire summer season of 2022 even in the face of reduced Russian pipeline flows, although in relative terms

81 Using GIE data, ACER has estimated that half of the storages' filling gap on 31 October 2021, in comparison to the five-previous years, must be at least attributed to Gazprom's behaviour. On 31 October 2021, total EU storage stocks held 19.6 bcm less than the average of the preceding years, while Gazprom's controlled sites held 9.5 bcm less than average. The nearly 20 bcm gap in gas stored stocks was overall maintained till 1 March 2022. In response to Gazprom's capacity hoarding, EU Member States introduced regulated access to storages or eventually took control of those assets.

the injections registered in the last months of the summer were more in line with those in 2021.

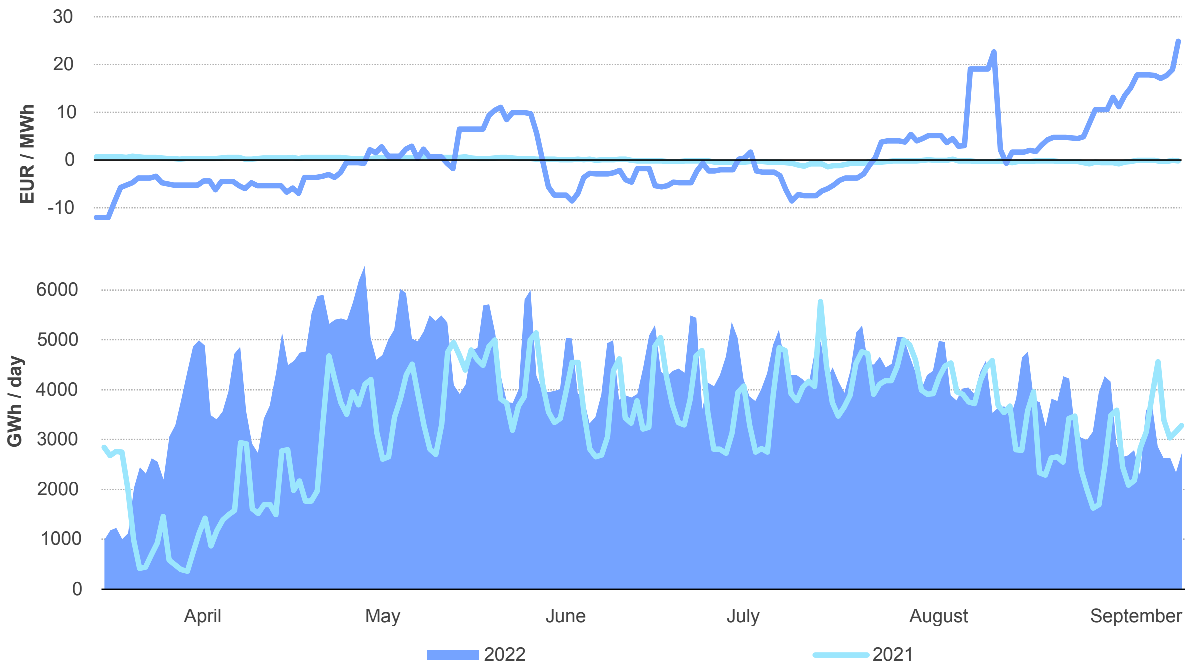
76 The need to replenish gas stocks was further emphasised on 1 June 2022, when Member States agreed to implement storage filling targets through EU Regulation 2022/1032. The Council Regulation sanctioned an EC proposal that had been put forth initially in March 2022. The Regulation introduced the obligation for Member States to achieve a minimum filling target of 80% of their storage capacity by 1 November 2022, which would be extended to 90% in following years, along with measures to establish the filling trajectory.

77 Importantly, Regulation 2022/1032 called for Member States to implement measures and to provide financial incentives to encourage storage injections during summer. These incentives were particularly relevant given the narrow, and even negative at some instances, price spreads between summer and winter months, which reduced the economic incentive for storage filling.

78 As shown in Figure 32, negative summer-winter spreads[82] were observed across April and May 2022, based on TTF hub prices. They were the result of the short-term price peaks emerging shortly after the Russian invasion of Ukraine in conjunction with a market sentiment pointing to prices gradually receding by winter 2022/2023, under the expectation that most Russian flows would be maintained. The negative summer-winter spreads, while going in principle against the economic logic, did not hinder robust daily gas injections into storages, which reached record highs during those two months.

79 Summer-winter spreads became favourable again in early June 2022. This shift was driven by the sharply climbing winter-season prices caused by the reduction in Russian flows, which introduced uncertainty regarding the EU gas supply resilience for winter 2022/2023. Overall, summer-winter spreads became very volatile, creating complexities in supply hedging strategies. For example, seasonal spreads turned negative again in mid-June 2022, during July 2022 and parts of August 2022. These negative spreads were driven by the record-high spot and prompt hub prices registered at those most critical weeks. preads moved again to positive values from the end of September 2022. Then, the record-high LNG imports moved temporarily prompt hub prices down, whilst the anxiety about the security of supply for the next winter 2022/2023 remained.

Figure 32: Overview of winter-season prices minus month-ahead prices (EUR/MWh) and daily storage injections (GWh/day) - summers of 2021 and 2022



Source: ACER based on GIE and ICIS.

Note: The spread is assessed as the price difference between the month-ahead product and the season+1 (winter) prices as daily traded during each of the six summer months. TTF prices are used as a general benchmark for the EU.

82 The assessment compares the winter season prices minus the front month-ahead prices; a negative value of that spread entails that gas prices for delivery in the next month were at premium to gas prices for delivery in winter season, hence a disincentive to injections.

2.3.3. Adaptive response: measures to boost storage injections came at a cost

80 Most Member States introduced ad-hoc measures to boost storage injections during the summer of 2022. Those measures took different forms, ranging from market tender processes to inject gas at storages, the enforcing of filling obligations to individual suppliers or the appointing of a public-backed entity to procure gas at national hubs to inject it at underground sites[83]. The measures frequently included financial incentives and public support schemes. A recent ACER study[84] has revised the different measures implemented at each Member State with input gathered from NRAs. The study also aims to assess the impact of the different measures to achieve the national storage targets as well as the measures' costs. Figure 33 initially offers a summary overview of the measures implemented per Member State. Table 4 in the Annex provides more insights into the effects and costs of these measures.

Figure 33: Overview of Member States' measures implemented to raise storage injections over the summer season 2022

	Minimum volume in gas storage	Tender of capacities	Balancing stock managed by TSO	Obligations imposed on designated entities	Coordinated instruments	Voluntary joint procurement mechanisms	Financial incentives for market participants	Unused booked capacities
AT	✓							✓
BE		✓						✓
BG	✓							
CZ	✓			✓			✓ (t)	✓
DE				✓			✓	✓
DK				✓				
ES	✓	✓					✓	✓
FR		✓						
HR	✓ (t)		✓	✓ (t)				
HU	✓							
IT		✓ (t)	✓ (t)	✓ (t)			✓ (t)	
LV								
NL							✓ (t)	
PL				✓				
PT	✓	✓						
RO	✓							
SE								
SK	✓							

✓: New measure implemented due to the Gas Storage Regulation

✓: Existing measure amended as a result of the Gas Storage Regulation

✓: Measure in place prior to the Gas Storage Regulation

(t): Temporary measure (applied only in 2022/23 and/or 2023/24)

Source: VIS Consultancy study, based on NRA's input.

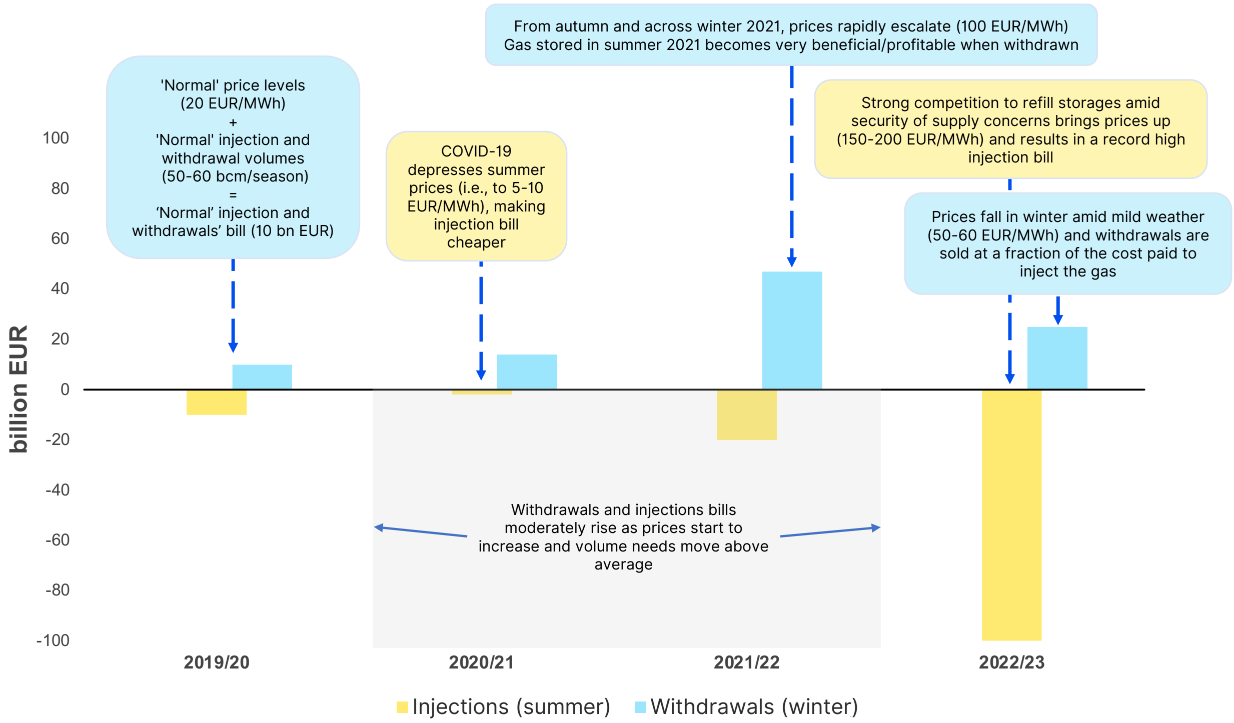
81 The combination of a high-price market environment and above-average injection volumes generally resulted in high gas storage injection costs. The actual injection costs depend on the contractual portfolios of the entities sourcing the gas and on the total injected volumes, which also varied substantially among Member States. Countries like Germany, Austria, and the Netherlands, with a higher presence of Gazprom storage sites and as such lower stock reserves at the end of winter 2021/2022, faced the largest relative stock deficits.

83 According to an EC Report that tracks how Member States met the mandate of EU Regulation 2022/1032, Member States implemented the following measures to achieve storage targets; 1)Imposing an obligation on the storage facility operators on the minimum filling level to achieve, in line with the national objective; 2)Tendering the capacities to market participants; 3)Having a mechanism in place for when the total capacity subscribed is below the minimum filling level, for example pre-agreed terms with market participants for the complementary volume; 4)Ensuring that the capacities booked are effectively used by applying a 'use it or lose it' mechanism or imposing penalties for non-compliance; 5)Finally, if the measures mentioned above are unlikely to produce the desired results, designate an entity to purchase the missing capacity from the wholesale market.

84 See ACER consultancy study on the impact of the measures included in the EU and National Gas Storage Regulations.

82 Under the hypothesis that all the EU injected volumes would have been purchased at average TTF month-ahead hub prices, a rough estimate results in a total EU injection bill of 90 billion euros during summer 2022, eight times higher than the average cost of the preceding five years, as shown in Figure 34[85]. This is a highest range estimate. The actual injection costs would have been lower in practice, as many suppliers likely hedged at least parts of the injected volumes' prices in advance. However, this perspective highlights the significant expenditure faced.

Figure 34: Storage withdrawal and injection costs at EU storage sites (billion euros) - 2019 - 2023



Source: IEA and ACER considerations. The assessment considers that all the storage injections and withdrawals during a month were priced at the average cost of the preceding month-ahead TTF price.

83 In some instances, the support measures introduced to boost storage injections would have increased as previously referred the upward pressure on hub prices. This was the combined result of above average injections adding to increase gas demand, but also the subsidised nature of certain measures that might in some cases not have led to the most efficient procurement strategies. While most governments primarily sought to incentivise market-driven gas storage filling, the market response to these incentivising measures was not sufficient in all cases to meet the Member State storage filling targets, consequently leading to the mobilisation of other measures which in various instances came with substantial public support.

Storage support measures implemented in Germany and Italy

The situation in Germany and Italy were examples of lagging market actors' responses leading to substantial public interventions. The volumes injected into the storage sites of these two Member States during the spring and summer months of 2022 were the largest in Europe in absolute terms (15.5 bcm in Germany and 10 bcm in Italy). The German government introduced first a market-based public tendering process, prioritizing market participants' responsibility for gas procurement and storage injections. It accompanied the tenders with additional financial incentives. The arrangement assigned the market area manager, Trading Hub Europe (THE), a role to serve as a last-resort purchaser and gas storer if the filling objectives were not achieved at a certain point in time. Eventually, the initial market response was limited and delayed, which led THE to procure 5 bcm of gas for injection in storage at a total cost of circa 9 billion euros by chiefly procuring gas with short-term products at the German gas trading hub. In addition, THE's strategy to hedge those volumes' prices has attracted certain controversy. ACER understands

85 The IEA has issued an assessment of the subject, reaching similar estimates.

that the gas purchases with short-term products at high price levels during the summer of 2022 were not sufficiently hedged by selling corresponding forward products[86]. Consequently, when gas prices collapsed in the following months, the value of the gas stored decreased, resulting in registered losses when sold but also for the volumes still hold by THE at the sites. Given strong regional market integration, the developments in the German trading hub are understood to have impacted on the supply-demand and price balances of neighbouring hubs. In addition, the net costs for the measures taken by THE are charged to the balancing groups (for domestic and cross-border exit allocations) by way of a gas storage levy, the so-called neutrality charge. The German storage developments have been thoroughly analysed in a report issued by the German Ministry of Economics in the summer of 2023[87].

The Italian government in turn initially promoted two-way contracts for difference, which are understood to have attracted a limited market interest initially. In parallel, it established an incentive for storage users, offering them a financial premium tied to their achieved stock levels, which is proved to be a more effective measure. Additionally, the government set zero reserve prices at the more frequently conducted auctions for storage capacity. Eventually, the Italian government assigned Snam and GSE companies a last resort filling role. In the case of the Italian system, the last resort entities contributed for approximately 3.5 - 4 bcm of gas storage filling at a total cost of 5.5 billion euros. These costs are to be recovered by selling the procured gas and borne by the domestic exit points in Italy.

84 Table 4 in the Annex complements the assessment of the support measures and their costs for other Member States. It does so, leveraging the analyses on the subject conducted in a recent ACER and CEER study.

2.3.4. Lessons learnt: engage market participants through a more gradual adaptation

85 As shown in Figure 33, Member States implemented a variety of measures to boost injections into storage sites during the summer of 2022. This was done, in part, to follow the mandate of Regulation 2022/1032. Member States defined their measures considering the existing national regimes and the specific departure scenarios but also adapted those measures to the gradual market response. The adaptation led in some cases to more interventionistic approaches. Overall, most measures were effective as they managed to attract and inject massive volumes of gas into storage ahead of winter 2022/2023. However, not all measures proved efficient in terms of costs.

86 It is important to appraise the efficiency and costs of the support measures within the emergency context of the summer of 2022. Low storage stocks would have magnified the market uncertainty, resulting in additional upward price pressure. Furthermore, lower stock levels could have led to supply scarcity in winter 2022/2023 under less favourable demand conditions. Therefore, in view of the risk of not reaching sufficient stock levels by solely relying on market initiative, various Member States implemented gradually more interventionistic measures. Some of these measures are however assessed to have resulted in high injection costs by fuelling intra-EU price competition above global gas price levels. Therefore, it is important to extract lessons from this experience. ACER and CEER are willing to contribute with consultancy studies.

87 During the summer of 2022, coordinated and effective gas procurement of storage volumes could have proved useful at those markets where the initial market response was limited. Such coordination would have been implemented at the national level, but with the possibility to expand its scope. This strategy could have been set by establishing gradual storage targets at delimited price levels, leveraging market input to define those price levels. This approach would have sought to incentivise market response and reduce in parallel the responsibility of TSOs and MAMs acting as last resort filling entities. Once the last resort entities began to acquire massive volumes of gas at short-term hub prices with public support, many market participants found themselves outcompeted (while some gas sellers maximised their gains). A more gradual adaptation to evolving market conditions could have engaged market participants better, leveraging their expertise and ultimately reducing injection costs. Understandably, implementing these aspects on short notice was challenging, but it's a mechanism worth considering

86 See for example and assessment on the subject by Euroactiv.

87 See German Ministry of Economics Energy Industry Act on the evaluation of the relevant storage Regulations report.

should similar price tensions arise again[88].

88 An exercise that has similarities with the proposal above related to the EU introduction in spring 2023 of a mechanism allowing demand aggregation and joint gas purchasing. The specific mechanism requires Member States to collectively procure gas volumes equivalent to at least 15% of their respective storage filing obligations. This mechanism has shown promising results in the first rounds[89], even though the current price context differs significantly from that observed in summer 2022. Joint purchasing has particularly proven attractive to gas buyers with limited experience in the LNG market, such as some traditionally and heavily reliant on pipeline contracts with Gazprom. Hence the platform has merit for ensuring a rapid response during emergency situations.

2.4. Driver 4: LNG price developments

2.4.1. Driver relevance: LNG's growing influence on EU gas prices

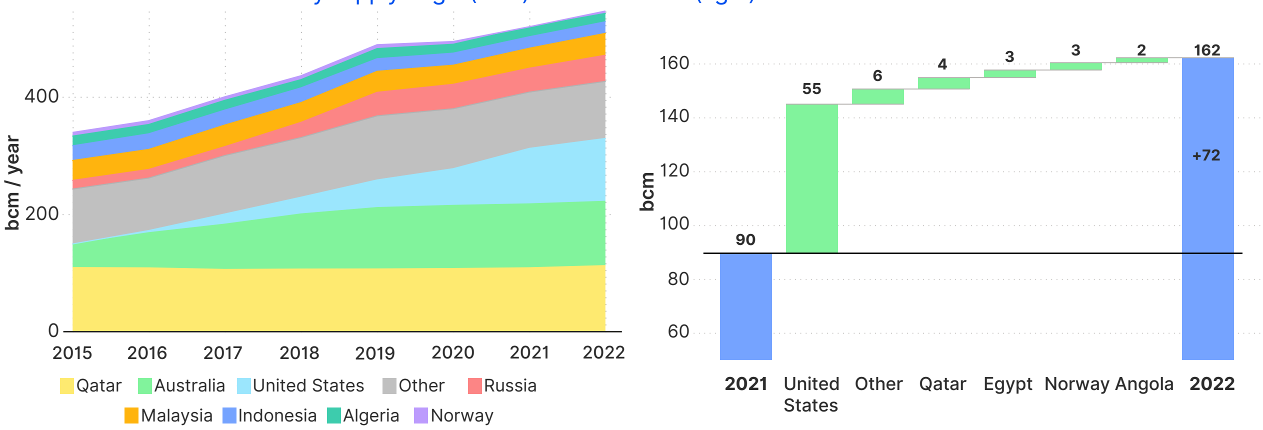
89 LNG supply is gaining a more important role in shaping natural gas prices in the EU. This significance is expected to strengthen further in the future, due to the EU's increasing reliance on LNG imports to reduce its dependence on Russian pipeline gas. Consequently, EU gas prices will be more exposed to global competition, as the LNG trading and pricing landscape is expanding and integrating more and more international actors and regions.

90 This section starts by assessing the dynamics in the LNG global market during 2022. The aim is to establish the context for understanding how global trends are influencing the European LNG market scenery lately.

Supply and demand developments

91 Global LNG production is largely distributed across two main ocean basins: the Atlantic basin, with predominantly European buyers, and the Pacific basin, mostly with Asian buyers. Leading global LNG producers distribute most of their sales in accordance with their geographical locations. However, the enhanced competition for global LNG resources, coupled with the development of price-responsive short-term markets, have made cross-basin LNG deliveries increasingly interdependent. During 2022, the four main LNG exporters Qatar, Australia, the United States and Russia were responsible for almost 70% of the global LNG output as Figure 35 (left) shows[90].

Figure 35: Evolution of LNG liquefaction volumes per producer (bcm) - 2015 - 2022 (left), and incremental LNG imports to the EU and UK by supply origin (bcm) - 2022 vs 2021 (right)



88 Sector associations have also offered considerations on the subject. Eurogas for example advocates among others to establish guidelines for good practice for seasonal balancing, to prevent large public disbursements and ensure responsibility of market players for storage filling.

89 See AggregateEU. For example, the first round of joint gas purchases organised in May 2023 managed to match circa 11 bcm while the second round reached circa 15 bcm from European buyers and potential suppliers. The supply-price tenders to match the aggregated demand were concluded, but the final exact prices of the contracts need to be sanctioned between the signing parts. Prices are overall required to track TTF. The expectation is that by pooling bigger volumes and coordinating they will result in lower values. Tenders will happen approximately every two months until the end of 2023, allowing companies each time to contract gas for the next 12 months.

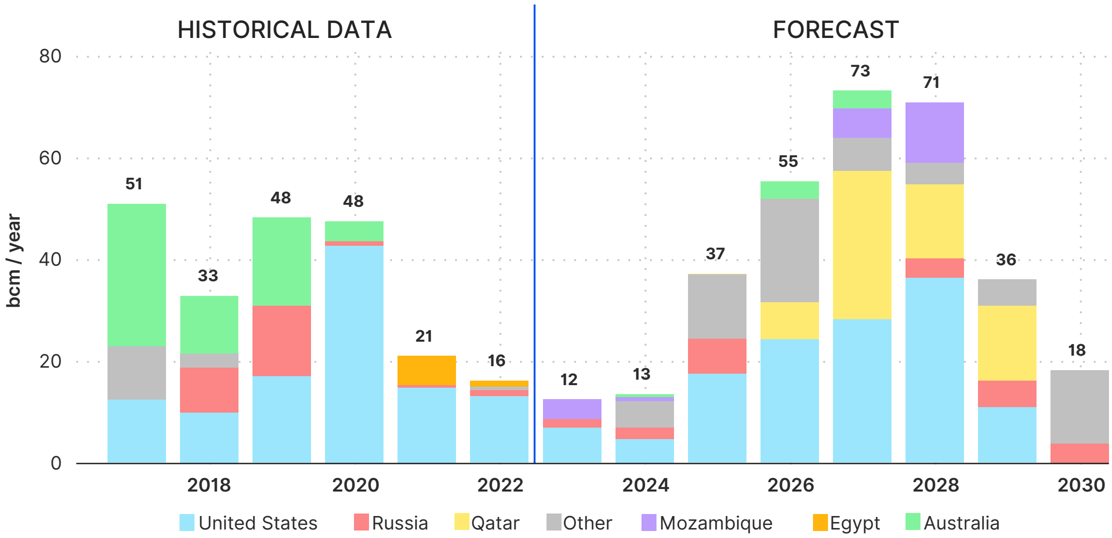
90 Qatar became the biggest LNG exporter with 112 bcm, overtaking Australia that exported 110 bcm. The US are diminishing their distance from the first two, with 108 bcm and Russia exported 44 bcm.

Source: ACER estimations based on Platts data.

92 Figure 35 (right) depicts the origin of the additional LNG supplies to the EU and UK in 2022 relative to 2021. Combined LNG imports increased by circa 72 bcm during that year. Figure 11, in Chapter 1 shows how, after the dramatic increase registered in 2022, the US is today the main source of LNG imports to the EU accounting for almost 60% of total EU LNG deliveries, followed by Qatar and Russia.

93 In 2022, global LNG production increased by 27 bcm in comparison to 2021, an annual relative rise of 5%. Higher load factors at various existing production facilities and the addition of 16 bcm/year of liquefaction capacity across the year[91] (an annual increase of 3%) backed the rise. Market prospects suggest that investments in LNG production will gradually increase, with more substantial rises in production anticipated from 2025. The rise will primarily stem from the new fields and liquefaction plants projected in the United States and Qatar, which are expected to enter into operation on that period as shown in Figure 36[92]. However, the relatively limited growth in global LNG supply until at least 2025 could potentially trigger intense global competition for available LNG resources, thereby leading to volatile pricing dynamics in the global LNG markets.

Figure 36: Overview of global LNG liquefaction capacity developments (bcm/year) - 2017 - 2030



Source: ACER estimations based on Platts data.

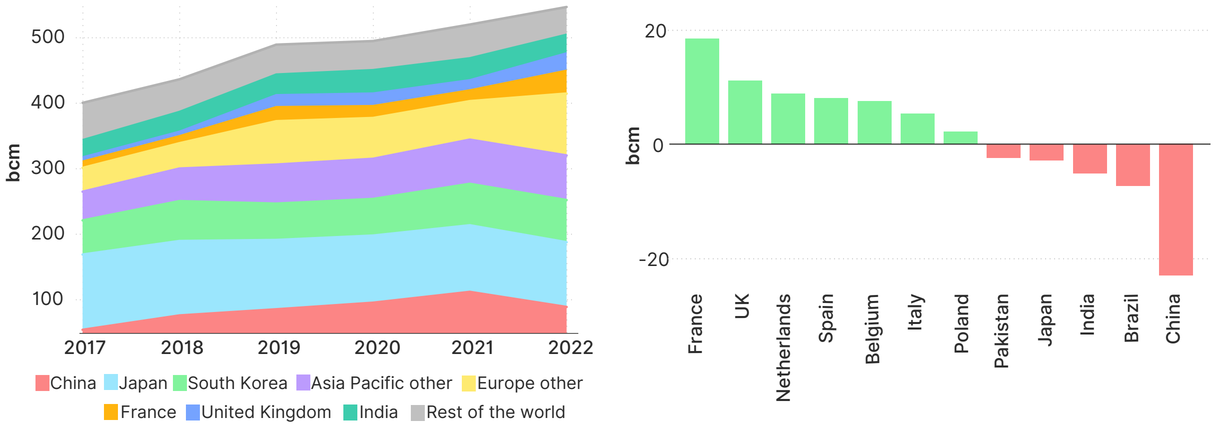
94 On the demand side, LNG consumption stood at 546 bcm globally in 2022, with the EU accounting for more than one-fourth[93]. Other important international LNG buyers were Japan (18%), China (16%), and South Korea (11%). Figure 37 (left) shows the evolution of global LNG demand since 2017, while Figure 37 (right) revises the incremental LNG demand developments during 2022. As both figures show, EU Member States significantly increased their LNG imports across 2022. In turn, LNG cargoes were diverted to the EU from various international markets including China, Brazil and India, attracted by the higher prices paid at European gas hubs. As a result of that diversion, and together with other factors discussed in Section 2.4.3, various Asian markets registered a decrease in their LNG demand. In some cases, this reduction led to energy shortages as was the case for Pakistan.

91 In accordance to IEA data, the Calcasieu Pass LNG liquefaction plant in the US, which came online in 2022, contributed around 14 bcm/year to global LNG capacity. Russia and Egypt also saw capacity expansions, adding 1.1 bcm/year and 1.2 bcm/year respectively. Notably, the additional 16 bcm/year capacity in 2022 is half of the average rise in the 2017-21 period. This decline can be attributed in part to LNG buyers' hesitancy to commit amidst uncertainties in long-term gas demand, soaring gas prices, and decarbonisation goals.

92 Various recent analyses elaborate on the subject. For example the recent analysis made by Rydstad for IOGP.

93 See EU Members States relative LNG import share in 2022 in Figure 10.

Figure 37: LNG demand per country of destination (bcm) - 2017-2022 (left), and incremental 2022 LNG imports by market relative to 2021 (bcm) (right)



Source: ACER estimations based on Platts data.

LNG contractual mechanisms and their impact on LNG trade

95 The contractual mechanisms that underpin global LNG trade have evolved over time. Today, as the case box below discusses, they range from long-term contracts[94] to spot and short-term cargo purchases that are traded most frequently on the basis of gas hub prices. The predominance of the contractual mechanism differs greatly across regions. Spot LNG transactions play a gradually increasing role overall, and specifically in the EU, where in accordance with IEA estimates 50% of LNG deliveries are currently procured on a spot and short-term basis[95]. Long-term contracts still have a more prominent role in LNG imports to various Asian markets such as South Korea and Japan[96].

LNG supply contract duration

Spot supply refers to LNG cargoes traded for the near term delivery, normally up to 3 months of the transaction date. Such spot LNG cargoes tend to shore into markets according to price signals.

Short-term supplies refer to LNG supply contracts comprising several cargos over a reduced period of time, ranging normally from several months or even one year to five years. These cargoes tend to fulfil specific and temporary needs that are identified and planned in advance. For those cases where needs could not be identified in advance, market players will have to resort to spot LNG trades.

Long-term contracts refer to LNG supply agreements for a predefined quantity to be supplied annually over a certain duration which is typically between 10 to 20 years. Annual volumes can be slightly adjusted according to certain flexibility clauses.

96 The nature and the predominant contracting schemes tend also to be different per LNG-producing country. For example, US LNG production is commonly contracted by means of a tolling fee that grants capacity access to liquefaction facilities, while natural gas is procured linked to Henry Hub indexation. Conversely, Qatar LNG production tends to be part of an integrated project comprising natural gas production, liquefaction and shipping, with very little to no flexibility for cargo diversions which most probably will be subject to profit-sharing mechanisms between the buyer and the seller.

94 See further considerations in OIES Report, LNG Markets in Transition: The Great Reconfiguration.

95 See IEA's Gas quarterly report Q4 2022.

96 See OIES Report Price reviews and arbitrations in Asian LNG markets. Other markets such as Pakistan, Bangladesh or India more highly rely on spot contracting.

97 ACER observes that over recent years, global LNG trade has become more flexible. This has resulted in the ability to further redirect shipments, adopt more flexible contractual terms and optimize the utilization of liquefaction and regasification infrastructure[97]. This transformation enabled the re-routing of significant LNG volumes during 2022, which were initially not contracted to be exported to the EU, as the subsection below revising below on LNG cargo reloads discusses.

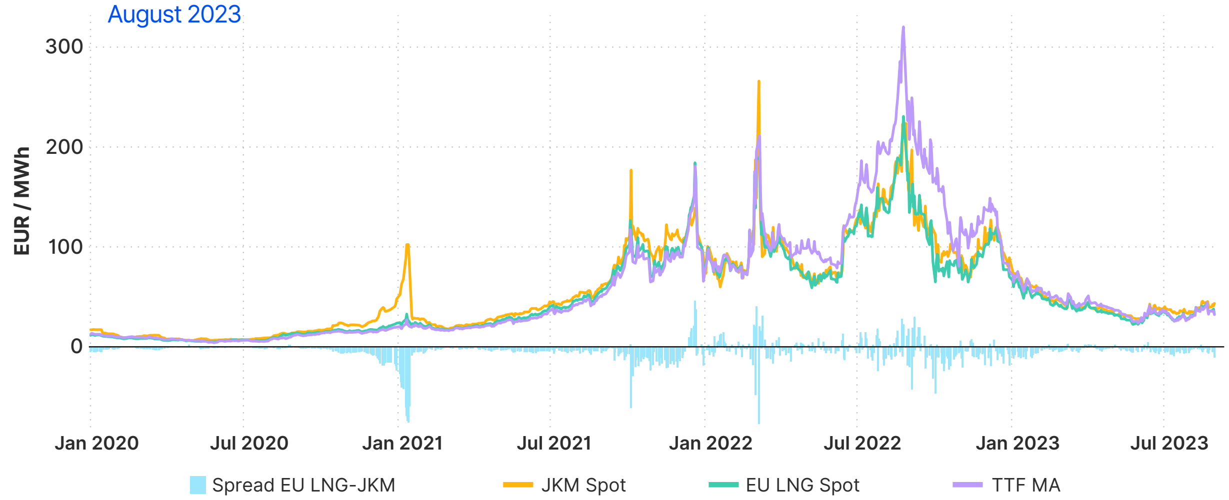
Europe's position: From a balancing point for the global LNG market to a competitor for LNG imports

98 Europe had historically acted as the global LNG balancing market. The EU offers the world's largest LNG regasification capacity subject to third-party access which is also able to reload LNG volumes from the import terminals to the LNG tankers. In addition, it hosts extensive underground storage facilities and offers significant flexibility to accommodate gas volumes, thanks to its significant ability to switch between gas and coal power generation. This unique framework had positioned Europe as the global market of last resort, enabling the redirection of LNG shipments to other markets when they offer better prices, or conversely, the attraction of larger LNG volumes during periods of abundant supply. Further assisting this role, the most liquid EU hubs have provided robust price signals for LNG pricing and granted shippers access to effective hedging instruments.

99 Partly due to this flexible role, and notably due to a historically more stable and competitively priced pipeline supply, Europe traditionally had accounted for a relatively modest share of the global LNG supply[98]. However, since mid-2021, the EU's global LNG imports started to rapidly increase, attracting most of the new spot LNG volumes sold. Starting in 2021 and critically throughout 2022, Europe's standing position in the global LNG market changed, shifting from its traditional role as a balancing point into a strong price competitor. This was due to the need to import massive LNG volumes to offset Russian pipeline gas.

100 As a result of this evolution, EU spot LNG price indexes surged above Asian LNG prices, which historically had been costlier. This was particularly the case during summer 2022 when the supply scarcity was more acute, as analysed in Figure 38. The figure compares the referential EU and Asian spot LNG contracts' price indexes against the evolution of TTF front-month prices. The latter denotes the prices for delivery of gas within the onshore virtual trading point. TTF prices reached even substantially higher levels, due to the accessing congestion at North-west EU terminals. The subject is further explored in Section 2.6.

Figure 38: Overview of EU and Asian spot LNG prices and of TTF front-month hub prices (EUR/MWh) – January 2019 – August 2023



Source: ACER calculation based on Platts data.

Note: 'EU LNG Spot' prices correspond to the average second half-month prices for delivery in North-West Europe and Mediterranean area assessed by Platts. 'Spread EU LNG-JKM' is computed as 'EU LNG Spot' minus 'JKM Spot'.

97 See, for example, OIES 2020 report LNG Portfolio Optimization: Challenge, Opportunity and Necessity.

98 I.e., including EU-27 MSs and the UK, European LNG imports accounted for around 20% of total international LNG trade and met 18% of European gas demand, over the last-five years' average.

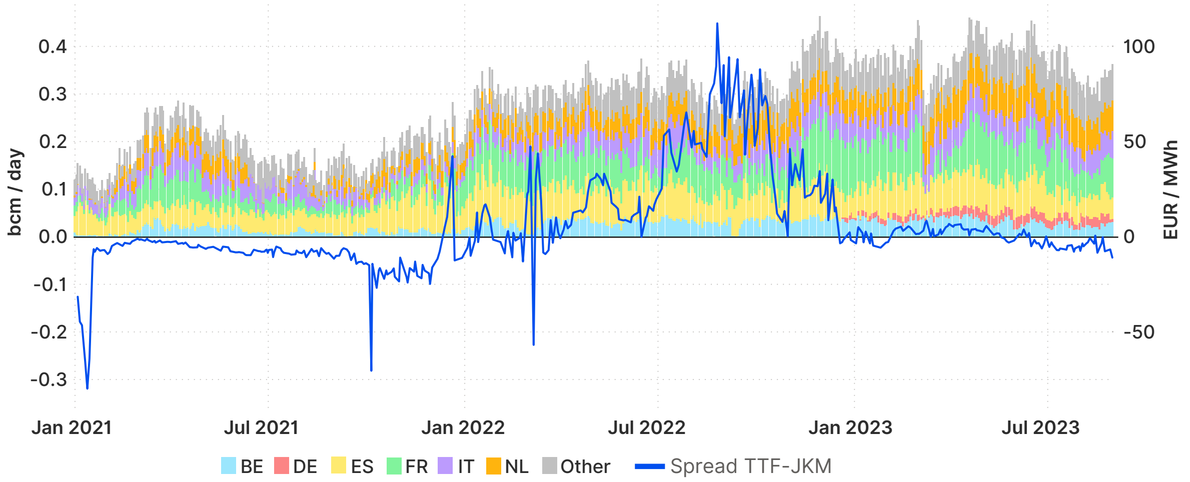
2.4.2. Overview of summer 2022: EU price signals enable the diversion of LNG cargoes

101 As previous sections have discussed, EU gas hub prices reached record highs from mid-2021 and throughout 2022. The elevated prices at EU gas hubs, exceeding the referential global LNG price indexes, triggered a reaction in the global LNG trading landscape. Established LNG import markets such as China or Pakistan experienced switches from gas to coal and/or registered demand reductions to subsequently face re-routing of contracted cargoes towards the EU. The global LNG supply chains adapted to the shifting environment, leading to surges in shipping rates and significant cargo reloads whilst the strong EU price signals enabled a substantial diversion of cargoes to the EU. Further details on all these aspects are discussed in this Section.

EU competition for global LNG resources and market impacts

102 Figure 38 shows the evolution of spot EU LNG and spot Asian LNG price references throughout 2022. Complementarily, Figure 39 compares the evolution of total EU LNG imports related to the price spread between TTF month-ahead products and the referential Asian spot LNG JKM index[99]. The figure reveals how the higher EU hub prices led to a greater share of LNG cargoes arriving to the EU.

Figure 39: Overview EU LNG send-outs (bcm/day) in comparison to TTF month-ahead vs JKM spot price spreads (EUR/MWh) – January 2021 – August 2023



Source: ACER calculation based on Platts and GIE.

Note: Positive spread values relate to TTF prices being at a premium to the JKM index. The figure shows the total LNG send-outs. While send-out values are well related to LNG imports, they tend to show a time gap of a few days. Hub prompt products are commonly used to negotiate the prices of spot LNG deliveries[100].

103 Within a tight global LNG market making spot LNG imports increasingly expensive, Asian markets, and particularly China, registered a significant reduction in LNG supply. The reduction in Chinese LNG import demand (minus 20 bcm year on year, a 22% drop) was overall driven by milder weather conditions and by lower-than-expected economic activity due to Covid-related policies. Some rising renewable power generation output also contributed to limited demand. Moreover, importantly, the lower LNG demand was also the result of Chinese buyers resorting to substituting natural gas for coal when EU prices supported the change[101]. The Chinese demand reduction played a crucial role in facilitating the increased

99 It should be noted that Asian import prices are based on different contractual clauses and indexes, which foresee different conditions for diverting cargoes.

100 LNG transactions can be done on the basis an outright fixed price, but they more frequently relate to an indexed price formula. The latter typically results in a floating price settled days after a transaction occurs.

101 Analysist such Karsten Neuhoff have assessed the levels at which fuel switching tends to occur in Asian LNG markets, where natural gas can be replaced by coal for power generation and by oil in other uses. Based on the comparative prices of these commodities, Neuhoff establishes a threshold of 40-50 EUR/MWh at which most of the cargo redirection occurs. This calculation takes multiple factors into account, such as contractual obligations enabling cargo reloads, destination clauses and the capacity of contract indexation to reflect supply and demand fundamentals. However, Neuhoff argues that, during 2022, TTF prices above a 70 EUR/MWh might not have attracted that significant additional LNG amounts, as fuel switching had already occurred at lower levels. See: Cambridge University working paper, Defining gas price limits and gas saving targets for a large-scale gas supply interruption.

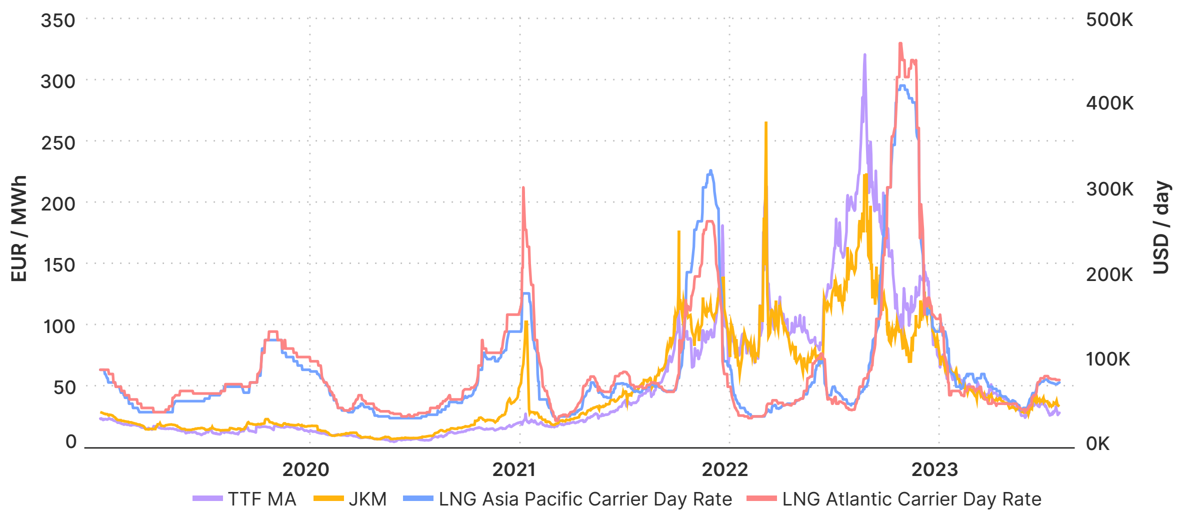
LNG imports to Europe. Chinese off-takers redirected substantial volumes of short-term cargoes to Europe, capitalizing on the favourable margins between EU hub prices and the prices derived from their portfolio's long-term contracts[102]. It should be noted that the decline in Chinese LNG demand observed in 2022 might not continue over time into 2023 and beyond when Chinese demand is projected to grow by 10%[103].

Developments in the global LNG supply chain: liquefaction capacity, shipping rates and cargo reloads.

104 While as stated, LNG production rose by 5% in 2022 relative to 2021, the rise was not sufficient to alleviate the tightness of the market amid rising LNG global demand. The utilisation rate of global liquefaction capacity averaged 87% in 2022, close to the 2017- 2021. Moreover, the utilisation rate in the second half of 2022 (86%) was relatively lower than during the first half of 2022 (89%)[104]. The latter decline was due to various unplanned supply disruptions, chiefly the extended outage at the US Freeport terminal, with a nominal capacity of 20 bcm per year. Technical issues and upstream underperformance at legacy plants were also observed in Algeria, Nigeria, Malaysia and Australia.

105 As regards shipping rates, as shown in Figure 40, the high and steady demand for extra LNG import cargoes to the EU led to an overall increase in LNG freight rates during 2022. The rise followed previous shipping cost price spikes occurring at the end of 2021[105]. Yet, during the beginning of 2022, freight rates temporarily eased due to the warmer winter temperatures, while they rose again from February 2022 following the Russian invasion of Ukraine. Freight rates substantially spiked upwards in summer[106] as the European gas storage obligations led to an increase in natural gas demand, but later in the year, as the winter turned out to be milder than expected and with storage inventories at high levels, prices decreased significantly.

Figure 40: Comparison between LNG freight rates (USD/day) and TTF MA - JKM prices (EUR/MWh) - January 2019 - July 2023



Source: ACER elaboration on Platts data.

Note: The price responsiveness of LNG freight is a sign of the flexibility that the global LNG supply chain was able to provide to ensure the re-routing of LNG cargoes.

106 Finally, the flexibility of the LNG supply chain to adapt to price differentials was notably reflected in the possibility to re-load and divert cargoes to destinations with higher market prices during 2022, such as to the EU. The cargoes diverted to the EU were higher in 2022 compared to previous years.

102 Shell statistics for example estimate that while 36 bcm of LNG shored into China contracted with spot and short-term cargoes in 2021, only 4.2 bcm were imported in that basis in 2022. Long-term contractual procurement marginally increasing in parallel.

103 Platts estimates at the month of August 2023.

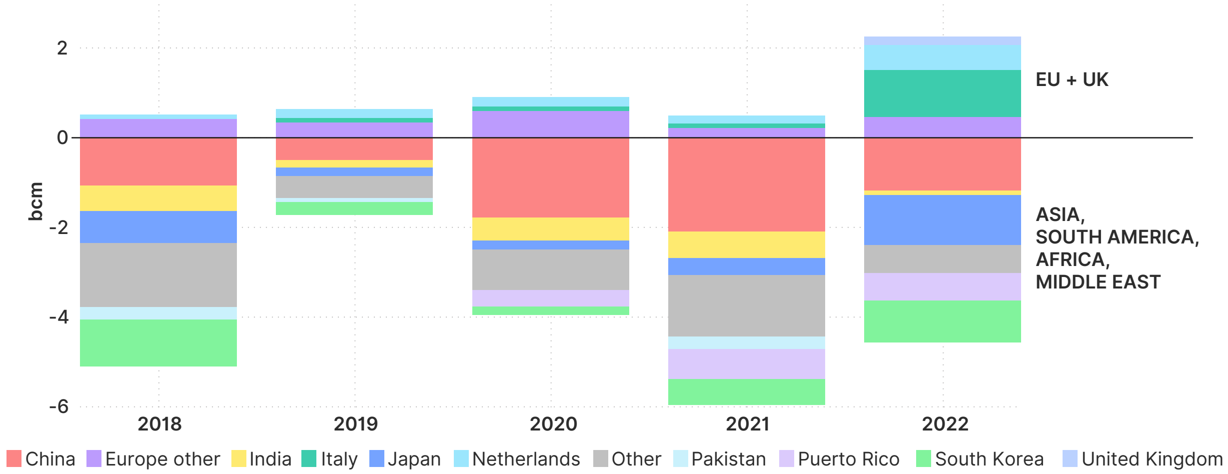
104 Analysed bases on Platts LNG statistics.

105 By October 2021, freight rates hit record levels as post-covid industrial demand surged, coinciding with a coal shortage in China.

106 West of Suez rates reached 250,000 dollar/day for steam turbine vessels, 355,000 dollars/day for TFDE/DFDE vessels and 450,000 dollar/day for X-DF/ME-GI vessels by the end of October 2022.

Figure 41 analyses the size of the reloads, distinguishing between the final destinations of the cargoes and highlights that reloads drastically increased in 2022. The figure shows that more than 2 bcm were reloaded in 2022 to Europe. Re-exported trade increased by 7% during 2022 from 6.5 bcm to 7 bcm, amounting to approximately 1% of global LNG trade in 2022. Europe loaded 32% of all re-exported volumes, followed by China with 17%.

Figure 41: LNG reloads by market of destination (bcm) - 2018 - 2022



Source: ACER calculations based on Platts data.

Note: Positive values are used for the European Market. Negative values for Asian, South American and Pacific markets.

Changes in EU LNG infrastructure utilisation in 2022.

107 European LNG regasification terminals adapted to the increasing demand for LNG imports. Not only the utilisation rates at EU import terminals increased significantly compared to previous years, but also terminal operators maximised the offered regasification capacity. These measures were a reaction to the high demand for LNG regasification capacity, which despite the efforts resulted in physical congestion at EU LNG import terminals pressing price formation up, as it will be further analysed in Section 5.4. Infrastructure congestion. The developments that led to additional LNG capacity investments from the end of the year are analysed in Section 2.4.3.

108 Table 2 in Annex I analyses the mechanisms that several Member States used to maximise the offered capacity to the market during 2022, including at the import terminals from Spain, France, Greece, Portugal, Italy, Belgium, Poland, Croatia and the Netherlands. This expansion was achieved by optimizing the available services (berthing slots, storage, and send-out capacity), thereby creating additional room for capacity.

109 The increase in LNG imports during 2022 led to a corresponding increase in the regasification rate of LNG terminals in the EU. The utilisation rates of each terminal have been already analysed in Figure 16 in Chapter 1. The average utilisation in Europe during 2022 spiked to 70%, up from 46% in 2021. In comparison, regasification utilisation dropped in Asia and Asia Pacific from 41% on average in 2021 to 35% in 2022.

110 Moreover, as a result of the enhanced utilisation of the terminals, the additional capacity offered and the overall higher competition to secure LNG capacities during 2022, significant premia was recorded in the offered capacity at LNG terminals in Belgium, France, Greece, Italy, Netherlands, Portugal and Spain. This resulted in an increase in the recovered revenue. Other terminals did not experience any premia (e.g. Lithuania). This information is summarised in Table 3 in the Annex I.

2.4.3. Adaptive response: expanded EU LNG capacity boosts import volumes

111 In response to the high energy prices seen in 2022, both policy initiatives and market players have aimed at enabling additional LNG imports into the EU. This response has been first articulated around constructing additional LNG terminals (various of them in the form of Floating Regasification Units,

FSRUs, as it will be discussed) and expanding the capacities of existing ones. Secondly, buyers secured additional supply contracts. Most regasification capacity additions have been located in the regions where congestion was the highest in 2022, which consequently led to significant capacity tariff premiums during 2022. The new terminals, located in the Netherlands and Germany have critically reduced the congestion premia in these markets.

112 The section additionally refers to the regulatory regimes applied to the new EU LNG infrastructure, in addition to the conditions under which new regasification capacity has been offered to the market.

LNG regasification capacity expansions in the EU

113 Since the end of Autumn 2022, the expansion of LNG infrastructure capacity played a crucial role in attracting increased volumes of spot LNG into the EU, gradually alleviating supply congestion, and hence contributing to reduce prices. Although some projects may still experience delays, it is anticipated that more than 50 bcm of LNG regasification capacity will be added to Europe between September 2022 and October 2023. This additional capacity will be able to meet over 10% of the European annual gas demand based on the average of the last five years. Table 1 offers an overview of the planned LNG capacity developments from mid- 2022 to 2025.

114 More than 10 European markets, including Germany, Netherlands, Finland, France and Italy, have initiated construction plans since the Russia-Ukraine conflict broke out. This includes 26 projects with a combined regasification capacity of circa 100 bcm. Nearly 70% of the new capacity will come from floating terminals, which can be brought online faster than onshore terminals. Of these 26 projects, 2 have been commissioned in 2022 and 8 have been commissioned in 2023 adding 38 bcm to global capacity as of July 2023. Four projects are under construction with a combined capacity of 20 bcm and the rest are still in the planning phase and shall be commissioned between 2024 and 2025.

Table 1: Overview of commissioned in 2022 and 2023 and planned additional LNG capacity in Europe

	Terminal	Type	Entry into operation	Planned duration (years)	Capacity	Regulation	Offered capacity
DE	**Wilhemshaven 01**	New FSRU	Dec 2022	10	Send-out: 154,2 GWh/day. Storage: 167,560 m3 LNG	Restricted third party access until March 2024 possible	152,1 GWh/d. Regarding the time frame until March 31st, 2024: restricted TPA, therefore no capacity was offered to third parties. Regarding the offer of capacity starting April 1st, 2024: capacity will be offered via the booking platform PRISMA.
	Wilhemshaven	New FSRU	Q1 2024	n.a.	Send-out capacity: n.a. Storage: 138,000 m3 LNG	Regulated	n.a.
	Wilhemshaven	New onshore	2026	n.a.	Send-out: n.a. Storage: n.a.	Proceedings for possible exemption underway	n.a.
	Brunsbüttel 01	New FSRU	Q1 2023	n.a.	Send-out: 112,4 GWh/day. Storage: 167,560 m3 LNG	Restricted TPA until March 2024 possible	112,4 GWh/d. Regarding the time frame until March 31st, 2024: restricted TPA, therefore no capacity was offered to third parties. Regarding the offer of capacity starting April 1st, 2024: capacity will be offered via the booking platform PRISMA.
	Brunsbüttel	New onshore	2026	15	Send-out: n.a. Storage: : n.a.	Exempted	n.a.
	Stade	New FSRU	Q1 2024	n.a.	Send-out: n.a. Storage: 174,000 m3 LNG	Regulated	n.a.
	Stade	New onshore	2026	n.a.	Send-out: n.a. Storage: n.a.	Exempted	n.a.
	Deutsche Ostsee.	New. Stage 1: one FSRU in Lubmin	Q1 2023	20	Send-out: 155,8 GWh/day. Storage: 145,130	Exempted	24,0 GWh/d. Interested parties were invited to place bids for LT capacity directly via e-mail to Deutsche ReGas
	Deutsche Ostsee.	Expansion. Stage 2a: 2 FSRUs (1 located in Lubmin - see stage 1 - and 1 located offshore)	Dec 2023	20	n.a.	Exempted	n.a.
	Deutsche Ostsee.	FSRU Expansion. Stage 2b: 2 FSRUs (both FSRUs located offshore)	Oct 2024	20	n.a.	Exempted	
EL	**Revithoussa**	Storage expansion	From July 2022 until June 2023		Storage: 145.611 m3 LNG	Same regulatory principles as the Revitthousa LNG terminal	Capacity was offered first-come-first-served, because the annual auctions had already been performed. According to the PAP, electricity producers had to store natural gas in the FSU for the winter 2022/23
	Alexandroupolis	FSRU	January 2024	25	153.500 m3 LNG	100% exemption from Art. 41 par. (6), (8), (10) (tariffs) Directive 2009/73/EC. This applies only for the part of the regasification capacity that has been booked through the Market Test related to Art. (32) (TPA).	174GWh/d (21.6 mil.m3/d). However, the National Natural Gas Transmission System cannot accommodate this capacity. More specifically, DESFA has offered: only 0.7 mil.m3/d of firm capacity (access to the Greek VTP), 10.7 mil. m3/d route product to IGB, 1.9 mil. m3/d to be consumed in the vicinity. Additional information can be found in the 2023 ACER report for the Greek national tariff consultation (link).

	Terminal	Type	Entry into operation	Planned duration (years)	Capacity	Regulation	Offered capacity
BE	**Zeebruge**	Expansion	2026	n.a.	Increase from 8.2 GWh/h in 2024 10.5 GWh/h in 2026.	Same rules applicable to the Zeebruge LNG terminal	Following an open season conducted in 2003 and a subscription window conducted in 2019, the entire primary capacity was allocated on a long-term ship-or-pay basis and commercialized by means of slots[107]. Occasionally, capacity is made available for LNG services on the primary market. In addition, LNG services can be traded on the secondary market. These LNG services are available to terminal users and other parties having signed the required contractual agreements. The capacity of the terminal in terms of the above slots, is fully subscribed until 2039-44. There were 4 contracts since 2004. However, there will be one single company having the totality of the above long-term capacity in the terminal since 2024 onwards.
FR	**Le Havre**	FSRU	September 2023	5 years	Send-out: up to 150 GWh/day. Storage: 142,750 m3 LNG	Exempted regime for 5 years (TPA and tariff regulation) [108]	50% of the capacity that can be offered over the 5-year horizon (starting from the start-up of the terminal) will be booked by Total Energies, based on a "ship or pay" model, at a reference tariff ("tarif de base"). The remaining half will be commercialized to third parties[109]. Capacity holders must release the berthing slots they do not intend to use during a contract year and a Use-It-Or-Sell-It mechanism will apply [110]
NL	**EemsEnergy Terminal**	New FSRU	September 15 2022	6 years	Send-out: max. 345,6 GWh/day. Storage: 180,000 m3 LNG 10 bcma as a bundled service. 8 bcma already in use	Exempted	Capacity offered through an open season, maximum 50% to a single party. Obligation for a use it or lose it mechanism. Capacity sold for full duration to 2 parties.
	Gate expansion. terminal.	Onshore terminal expansion	October 2026	20 years	Send-out: max. 127.20 GWh/day. Storage: 180,000 m3 LNG 4 bcma as a bundled service. 16 bcma already in use	Exempted	Capacity offered through an open season, maximum 50% to a single party. Obligation for a use it or lose it mechanism. Capacity sold for full duration to 2 parties.

107 Under such slots, terminal users are allowed to: arrive and berth their LNG vessel within a defined window, use basic storage capacity of 140 000 m^3 LNG, linearly decreasing over 40 tides, use a basic send-out capacity of 4 200 MWh/h during the abovementioned 40 tides.

108 CRE issued a deliberation to provide its opinion on Total Energie's exemption request. The government published a ministerial order on 21 April 2023 to grant the exemption and the conditions.

109 According to the following steps:
- A binding open season is organised, during which market participants indicate the annual capacity they want to book, the subscription period, and the price which can include a premium on top of the reference tariff. Participants' offers will be ranked based on their contribution to Total Energies' Net Present Value (NPV) over the 5-year period.
- The unallocated capacity is reoffered to the market each year N-1, for capacity available from the beginning of year N until the end of the 5th year of the terminal.
- Any remaining capacity (at the end of year N-1 for capacity for year N) will be first offered to current capacity holders (including Total Energies) at the reference tariff. Then, the remaining capacity will be offered for each available berthing slot on a FCFS basis at the reference tariff, or through an auction with the reference tariff as a reserve price.

110 Capacity holders must inform Total Energies in advance if it is not willing to use a slot and indicate the reserve price for it (not exceeding the reference tariff). Total Energies will propose the berthing slot to all registered customers (including Total Energies), which will be allocated based on the highest price offered.

	Terminal	Type	Entry into operation	Planned duration (years)	Capacity	Regulation	Offered capacity
IT	**FSRU Italia, Piombino**	New FSRU	July 2023	20 years	Send-out: 136.9 GWh/day. Storage: 167,818 m3 LNG	Regulated	In the auction for the long-term capacity 86% capacity for 20 years has been allocated to 5 companies.
	Adriatic LNG, Rovigo	Offshore expansion	December 2022	25 years	Send-out: 288.6 GWh/day. Storage: 250,000 m3LNG	Hybrid (71,1% exempted, 28,9% regulated)	n.a.
HR	**Krk LNG terminal**	FSRU expansion	1st October 2025	17.6 (includes existing terminal and expansion)	Send-out: 185 GWh/day. Storage: 140,206 m3LNG	Regulated	Additional capacities will be available and offered to the market from 1st October, 2025, from the beginning of the gas year 2025/2026. Terminal's Rules of Operation (Official Gazette 87/21, 72/22) envisage Annual Capacity Booking procedure for LT capacities (up to 15 years), based on first-come-first-serve principle and continuous opportunity to book remaining free capacity on LT or ST basis. Currently, there are six capacity holders for existing capacity.
PL	**Gdańsk Gulf FSRU**	FSRU	2028	n. a.	Approx. 6.1 bcm/ year	Regulated	Open season

Source: ACER based on NRAs.

115 Floating terminals also offer more flexibility as a shorter-term solution and require lower fixed investment. This is viewed as an advantage corresponding with Europe's long-term plans to reduce gas demand as part of its energy transition goals. Under EU taxonomy, gas-fired plants built through 2030 will be recognised as a transitional energy source, which contributes to the speed-up of terminal constructions in Europe.

116 The regulatory framework applicable to the new LNG infrastructure has varied across Member States. The main aspects relate to the application of third-party access, the procedures for offering capacity products, the type and extent of offered capacity products and the application of congestion management rules. These rules nonetheless significantly differ across LNG import terminals, as despite some improvements, the harmonisation of the access conditions has been historically limited[111]. CEER reports have consistently analysed those aspects and the type and evolution of these access regimes[112]. Table 1 above summarises the applicable regulations in the new LNG terminals and the expansions.

LNG contracted volumes

117 The increase in LNG regasification capacity occurred in 2022 and 2023 has often occurred without the concurrent contracting of long-term supply agreements, which would ensure a steadier source of additional gas. This implies that European buyers are relying mostly on short-term contracts to meet the additional LNG imports, leveraging the existent short-term LNG supply. In 2022, only a few new long-term supply contracts were reported to have been signed by EU suppliers – some estimates point to less than 15 bcm[113]. The growing volumes of LNG available from LNG portfolio aggregators have enabled more buyers to get into the LNG market, as they do not need to enter into long-term offtake agreements directly with LNG producers themselves, with the aggregator providing greater contractual flexibility.

118 Overall, EU buyers have been cautious about signing new long-term contracts and in several cases, they have refrained from renewing existing ones. This caution regarding long-term procurement primarily has been driven by the escalating EU decarbonisation targets creating some uncertainties about the future role of gas but also due to the more flexible demand and price requirements of downstream gas clients within the EU.

111 See the European Commission's 2020 Study on Gas market upgrading and modernisation – Regulatory framework for LNG terminals.

112 See for example CEER Report How to foster LNG Markets in Europe.

113 See for example further considerations on the topic in this Energypost article.

119 The few long-term contracts recently signed by European buyers are believed to have shorter durations (around 10 to 15 years) compared to those signed by Asian companies, which tend to have a duration of 20 to 25 years. Furthermore, it's understood that EU buyers have sought increased flexibility in aspects like cargo diversion. This flexibility however appears to have led to higher pricing demands from LNG producers. These added costs were demanded by LNG producers to mitigate their risks, given that longer supply commitments enable to better finance and develop their production projects.

2.4.4. Lessons learnt: a transparent LNG access system is crucial to foster competition

120 LNG has emerged as the primary alternative to offset the decrease in Russian pipeline supply volumes, in addition to a key source of flexibility to accommodate shifts in demand. At the same time, the future role of LNG in the energy mix over the coming decades is subject to uncertainty and will be impacted by the speed of decarbonisation and demand reduction targets. The speed of the decarbonisation trajectory will influence the EU's willingness to attract LNG. Consequently, the contractual frameworks to attract LNG will be shaped accordingly.

121 The disruption of Russian supply to the EU increased the competition for spot LNG imports, thereby tightening the LNG global market dynamics. Europe's higher reliance on spot LNG imports during 2022 required outcompeting LNG originally contracted for other destinations and triggered a surge in international LNG prices. During 2022, the relatively lower economic performance in China and the high EU hub prices supported the re-routing of LNG cargoes to the EU. However, those global supply-demand and price equilibria might not consistently favour the EU or would require the consistent outbidding of global LNG competitors to guarantee LNG imports to the EU. So far, Europe has held a partial reliance on shorter-term contracts, as opposed to other global LNG importers, such as Japan and South Korea who have mostly relied on long-term contracts to enhance security of supply.

122 The future of LNG imports remains hence a crucial topic of discussion, with some advocating that long-term LNG imports are critical and should be supported by an adapted legal framework. Others argue that spot and short-term contracting by market participants, linked to gas hub developments should maintain their central role in gas trading and price discovery, providing as such a more flexible framework that adapts better to the more volatile European energy landscape.

Regulation: Third party access to EU terminals

123 Another aspect that has received renewed attention in relation to LNG is the regulatory framework governing the new terminals. Amidst the supply crisis and to encourage a rapid development, certain new facilities were granted negotiated Third Party Access (TPA) regimes and limited transparency obligations.

124 A recent study being conducted by CEER will compare the terms of the regulated TPA access regimes with the non-regulated access regimes for the existing and different new terminals. The study calls for caution regarding the potential implications of less transparent access regimes for the future gas system. It is crucial to promote a transparent access system that fosters competition to the benefit of the EU hub development while also considering specificities that may apply to certain projects.

125 The allocation of capacity in the short and long term is also an important issue going forward. These approaches to capacity could likely impact the access conditions to this infrastructure and the competition in EU hubs. The allocation of capacity at EU terminals has resulted in capacity offering for very long periods of time and in terminals where only a single shipper is active. These conditions should be monitored to assess the impact on competition in the EU internal market.

2.5. Driver 5: Transmission infrastructure congestion

2.5.1. Driver relevance: infrastructure costs implicitly factored in gas prices

126 EU gas markets rely on LNG regasification terminals and transmission pipeline infrastructure to receive gas from third countries and transport it across Member States. Infrastructure operators incur investment and operational costs, which they transfer to gas network users to ensure their business operation.

Those costs are determined through regulated transmission tariffs and access fees for LNG terminals.

127 The costs associated with infrastructure use are implicitly factored in the price of the gas traded at hubs. This linkage is explained in the case box below, which discusses how the price spreads between hubs establish the intrinsic value of transmission capacity.

Case box: transportation versus locational swap

Consider a trader having procured gas at price P_{sup} in market A and having a contract for physical delivery of that gas at price P_{con}, in market B.

The trader can execute a swap of locations. To do that, it would sell the initially procured gas to a counterparty in market A at the price P_{hubA}, whilst it would buy gas from a counterparty in market B for price P_{hubB}. This operation would be profitable if the hub spread $|P_{hubB} - P_{hubA}|$ is smaller than the margin of the physical delivery contract $|P_{sup} - P_{con}|$. By doing a swap, the trader does not need a transport contract, as the gas is not physically moved between the markets. A swap could be as such considered virtual transport.

The trader can also transport the gas from market A to market B. That requires the booking of transmission capacity to exit market A (paying an exit tariff T_{ExitA}) and to enter market B (paying an entry tariff T_{entryB}). This transaction is profitable if the margin of the delivery contract exceeds the total transmission tariff $|T_{ExitA} + T_{entryB}|$.

The hub spread thus represents the intrinsic value of the transmission capacity. In other words, if the hub spread exceeds the transmission tariff $|T_{ExitA} + T_{entryB}|$, it is more profitable to transport gas from market A to market B. Moreover, a capacity contract represents a right to use the transmission capacity, but not an obligation; as such it offers gas traders a hedge against volatile hub spreads.

128 Gas network users acquire transmission capacity rights in explicit capacity auctions[114]. Those auctions are hosted at present on three different cross-border booking platforms, each covering different regions: GSA Platform, PRISMA and RBP[115]. In these auctions, transmission capacity is allocated to the users with the highest willingness to pay. When no congestion is anticipated, network users bid at the regulated transmission tariff. However, in a congested market, certain network users might be willing to pay a tariff premium to obtain exclusive transmission capacity rights. That premium is related to the intrinsic value derived from the anticipated price spread between the interconnected hubs[116] and generates additional revenues for the TSOs[117].

129 Transmission capacity rights cover different durations: yearly, quarterly, monthly, daily (i.e., 24 hours of the next day) and within-day (all remaining hours of the ongoing day). For yearly and quarterly products, capacity auctioning takes place a few months ahead of the contract maturity. For monthly products it occurs a few days ahead, while for daily and within-day capacity products it happens hours ahead. As the transmission capacity auction schedule is not perfectly synchronised with the trading of gas hub products, market participants must independently align their trading positions and their booking of capacity rights[118]. In doing so, they need to anticipate future hub prices and the worth of transmission capacity.

114 The allocation of cross-border transmission capacity is governed by the Capacity Allocation Mechanisms Network Code (CAM NC).

115 For completeness, very few interconnection points apply implicit allocation procedures, in which the allocation of transmission capacity follows confirmed gas transactions. This implicit allocation procedure is applied at the interconnectors between Belgium and the UK (Interconnector) and the Netherlands and the UK (BBL), at Balticconnector between Finland and Estonia and few interconnection points in the Baltic countries.

116 Market players might be inclined to pay prices for capacity that surpass hub spreads due to the added option value of having exclusive capacity rights. In uncongested markets, spreads may approach zero or even fall below the capacity tariff, which acts as a minimum reserve price to secure capacity in the auction.

117 The use of the congestion revenues is governed by the Network Code on harmonised transmission tariff structures for gas (NC TAR). In essence, these revenues have to be returned to network users or to be used for relieving physical congestion.

118 In the case of implicit allocation procedures there is no coordination challenge, as transmission capacity is allocated according to confirmed gas trades.

130 When the market anticipates increasing gas prices and capacity scarcity, the intrinsic value of transmission capacity rises. Consequently, the congestion-induced tariff premium tends to rise. This is reasonable because market participants place greater value on the option of securing the transmission capacity rights that grant control over gas flow. This enables them to trade (or abstain from trading) between markets with diverging prices.

131 The impact of transmission tariffs on gas price formation had traditionally been relatively modest, as congestion levels in Europe historically remained low[119]. However, in the summer of 2022, acute congestion significantly affected gas prices.

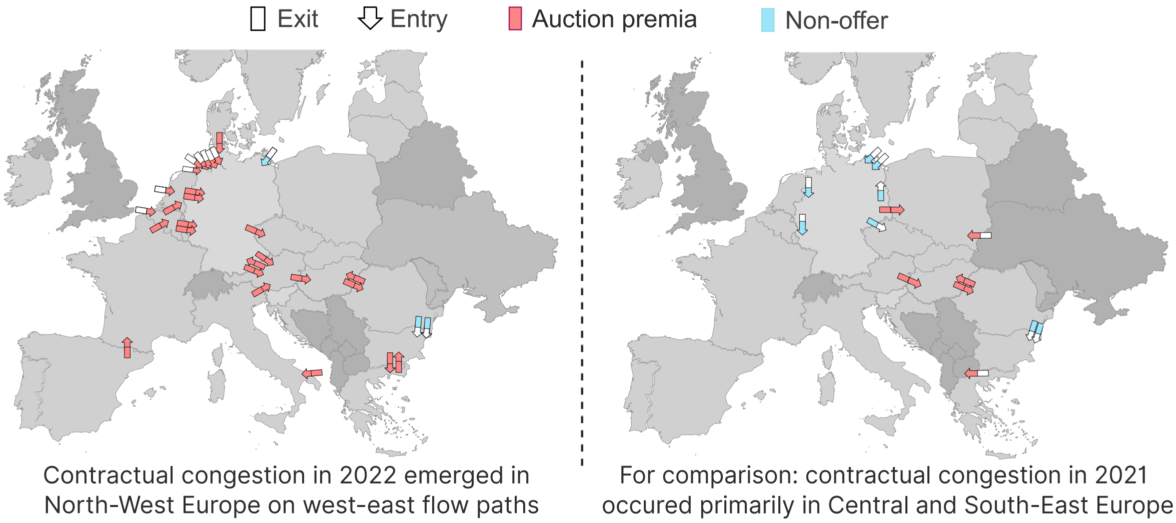
2.5.2. Overview of summer 2022: Infrastructure congestion leads to high hub spreads

132 This Section first discusses how the supply shift away from Russia resulted in significant infrastructure congestion across the EU. Subsequently, the Section analyses how that congestion influenced price formation and led to record high spreads between selected hubs in that period.

Restructured gas supply routes led to acute congestion in EU transmission networks.

133 The most recent ACER's Report analysing congestion in EU gas markets[120] reveals a tripling of transmission networks' congestion in 2022 relative to the year 2021. That congestion primarily emerged at the interconnection points within North-West Europe, as Figure 42 shows. The higher congestion in that area was due to the region's historically higher relative dependency on Russian supplies, and hence the need to substitute higher volumes of gas supply.

Figure 42: Contractually congested cross-border Interconnection Points - 2022 compared to 2021



Source: 10th ACER Report on Congestion in EU gas markets and how it is managed.

Note: ACER identifies congestion at interconnection points based on the criteria in Point 2.2.3.1 of Annex I to Regulation (EC) No 715/2009 which refers to the occurrence of auction premia, or the absence of a capacity offer (non-offer).

134 ACER's special report on addressing congestion in NWE gas markets[121] specifically analyses how supply congestion was the highest in accessing the Netherlands and Germany. Congestion emerged due to the need of speeding LNG imports, but also alternative pipeline flows at western-entry interconnection points, within a system originally structured for transporting Russian supplies to Europe in an east-to-west direction. The missing Russian pipeline flows were mainly replaced by LNG supplies shoring at terminals located in the northwest of the continent, but also in the UK. This LNG flowed then in the eastern direction through the existing continental onshore pipelines. The offshore interconnectors with the UK significantly ramped up their use as has been analysed in Figure 12. Additionally, the Norwegian supplies to Europe across the North Sea reached record levels. With the opening of the Baltic Pipe at

119 See ACER Reports on the status of Congestion at Interconnection Points.

120 See 10th ACER Report on Congestion in the EU Gas Markets and How it is Managed issued in May 2023

121 See ACER Report addressing congestion in North-West European gas markets issued in 24 July 2023.

the end of the year, of up to 10 bcm of annual capacity, Norwegian gas started flowing also to Denmark and Poland, relieving somewhat the stress on the North-West European transmission system.

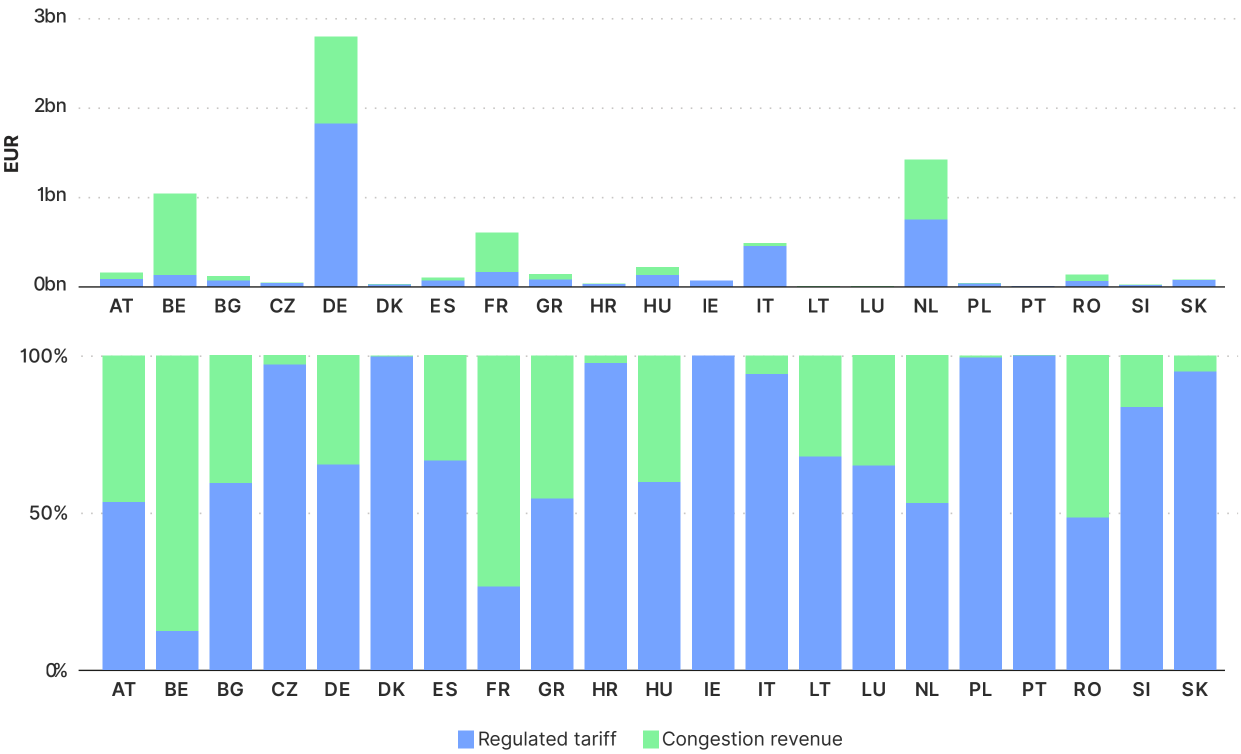
135 Significant supply bottlenecks emerged despite gas demand in North-West Europe being lower than in previous years, as for the reasons discussed in Section 2.1. To address these bottlenecks in the short term, TSOs optimised the existing infrastructure to accommodate the changed supply routes. Their adaptive actions are elaborated on in Section 2.5.3.

The intricate interplay between gas network congestion and hub spreads resulted in both reaching record highs during the summer of 2022.

136 The shifting use of the EU gas system led to significant physical congestion at LNG terminals and cross-border pipelines in NWE, driving price spreads to record highs during the summer of 2022[122]. As Figure 4 and Figure 5 in Chapter 1 have shown, while spreads between EU hubs historically hovered between 1 and 3 EUR/MWh, they rose above 100 EUR/MWh in that period.

137 Network users competed for the scarce capacities offered and paid significant auction premiums to secure them. This was because the intrinsic value of capacity turned very high amid the increasing hub prices and the rising price volatility. EU TSOs recorded 3.4 billion euros in gas congestion revenues in 2022, of which 2.98 billion euros (or nearly 90%) was earned by NWE TSOs of Belgium, France, Germany and the Netherlands. For comparison, the EU's total gas congestion recorded revenues in 2021 reached 55 million euros. The share of congestion revenues in the total transmission income varied significantly between countries, as Figure 43 shows. The weighted average for all EU systems reveals that congestion revenues represented 45% of total TSO's income in 2022, significantly surpassing the 3.7% share in 2021.

Figure 43: Tariff revenues and congestion revenues recorded by transmission system operators in transmission auctions held in 2022 (billion euros) (top), and the tariff versus congestion shares (%) (bottom)



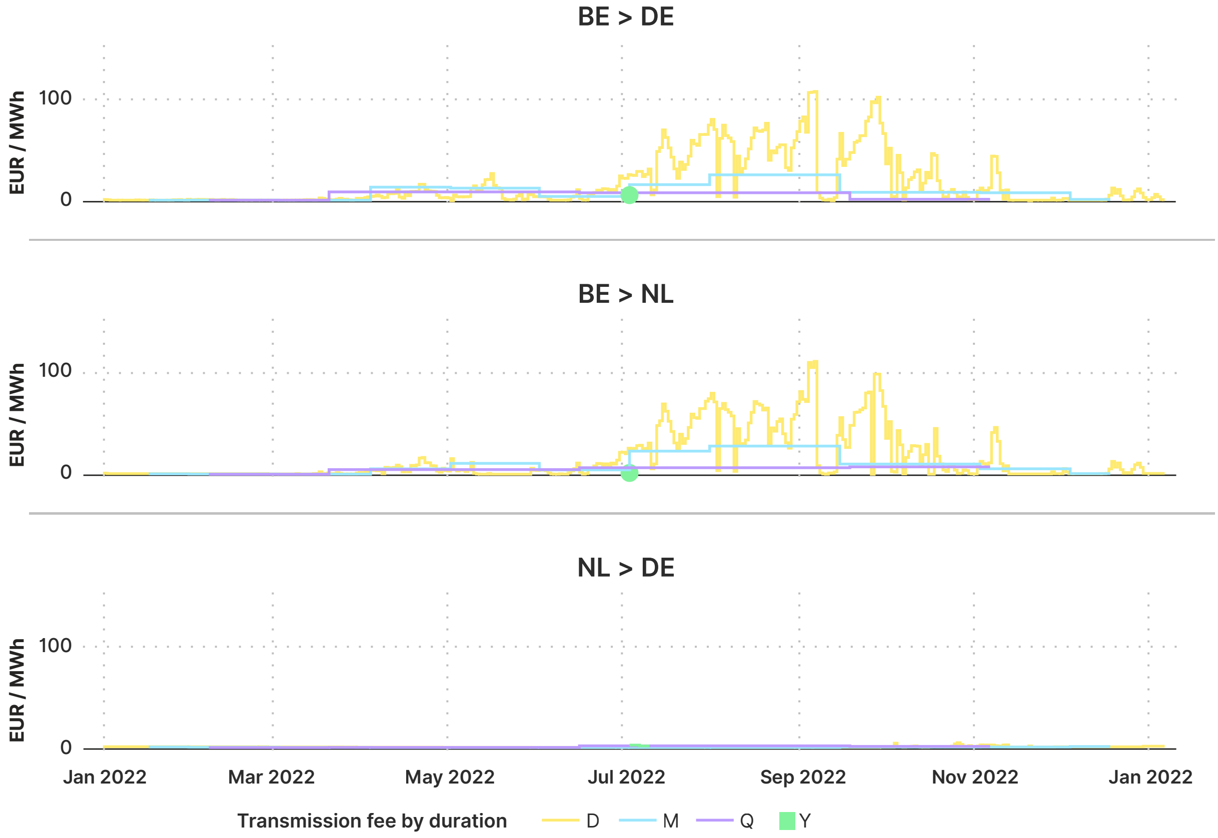
Source: ACER calculation based on auction data from GSA Platform, PRISMA and RBP.

Note: Part of these revenues pertains to forward capacity contracts to be used after 2022 and effective payments occur when the contract maturity date is reached. Countries depicted are those where TSOs use auction procedures for allocating transmission capacity.

122 While network congestion prevented prices to converge, and thus was driving hub spreads high, it is difficult to determine the causality between the transmission fees paid and the prevailing hub prices as the transaction times for transmission capacity and for gas are not synchronized.

138 Supply bottlenecks were most pronounced at the interconnection points linking the Dutch TTF and German THE hubs with Belgium and France. While the two hubs' prices disconnected from other European hubs, they continued to maintain a significant degree of alignment between themselves. Figure 44 shows how the transmission fees to access TTF and THE from Belgium reached record highs, whereas the transmission costs between the Netherlands and Germany were modest and close to the reference tariff level. The strong price convergence between Germany and the Netherlands was attributable to the absence of a structural shortage of physical capacity at this border, limiting the intrinsic value of capacity[123].

Figure 44: Transmission fees between Belgium, Germany and the Netherlands for different capacity product durations at the time of the auction (EUR/MWh) – 2022



Source: ACER calculation based on auction data from GSA Platform, PRISMA and RBP.

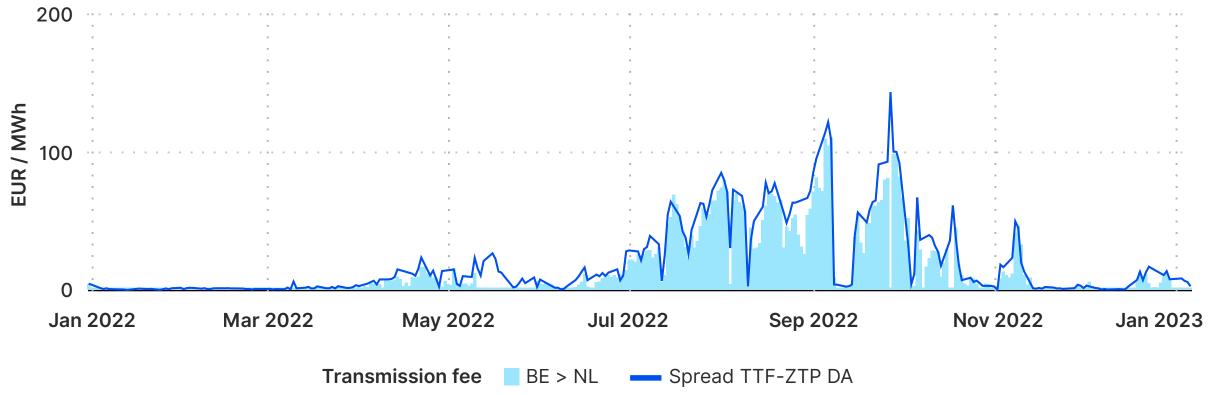
139 The intrinsic value of capacity differed per product duration. The day-ahead product had the highest intrinsic value, as market participants favour this timeframe for optimizing and balancing their gas contracts, including for physical delivery. Complementarily, day-ahead hub trading products registered the highest price spreads. The more rapidly shifting short-term market dynamics tend to result in higher day-ahead price volatility compared to forward curve products.

140 ACER has analysed the historical correlation values – i.e., before, during and after summer 2022 – of those transactions wherein a market participant engaged on both a day-ahead gas trade and a related day-ahead transmission capacity booking. The analysis reveals a strong correlation between the transmission costs and the hub spreads at the borders between Belgium to the Netherlands (see Figure 45), and between Belgium and Germany (analysed in Figure 47). Before summer 2022, the day-ahead hub price spreads hovered around the reference day-ahead transportation tariffs, reflecting a well-integrated market with limited infrastructure congestion. However, during summer 2022, congestion led to significant auction premia at those borders. These premia were intrinsically tied to correspondingly high hub price spreads.

123 The conversion of the usual capacity-based price of transmission capacity into an energy-based 'transmission fee' can be done by assuming a load factor for flowing gas. For instance, when a daily capacity product allows to flow 1 MWh/h per day, the user can flow 24 times 1 MWh/h for a total of 24 MWh. Assuming a price of 12 EUR for the daily product and a 100% load factor, the equivalent price would be 12 euro for 24 MWh, or 0.5 EUR/MWh. Transmission fees cover both exit and entry and where several interconnection points or several transmission products exist, the maximum fee is taken into consideration.

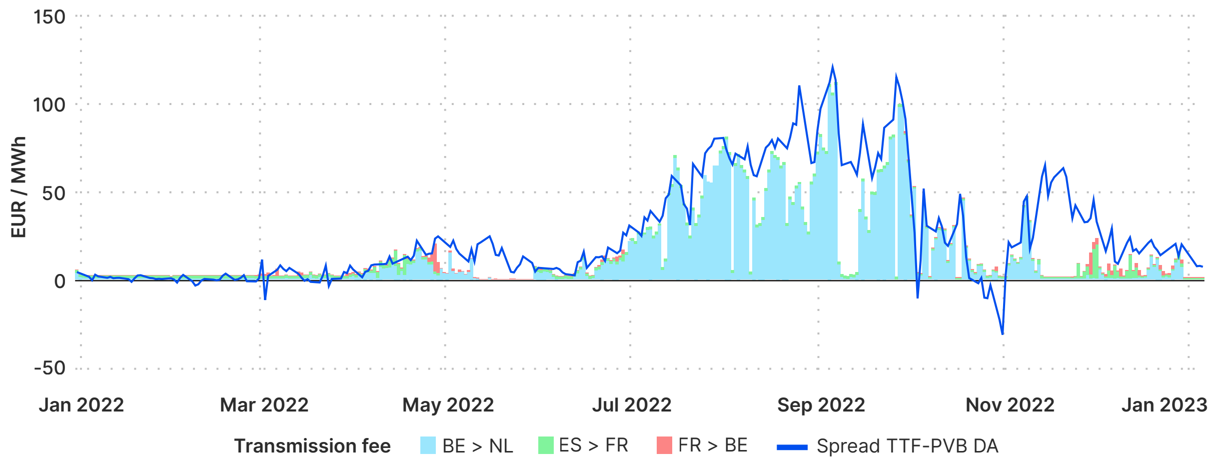
141 Figure 46 does a similar analysis for a longer supply corridor. In this case, gas flow from a prominent LNG entry market such as Spain to the Netherlands, via France and Belgium. In this case also a significant, although slightly weaker, correlation between the sum of the transmission fees along the corridor and the price spread between the TTF and Spanish PVB hubs can be observed.

Figure 45: Day-ahead hub spread between TTF and ZTP hubs and levelized cost of day-ahead transmission capacity from Belgium to the Netherlands (EUR/MWh) - 2022



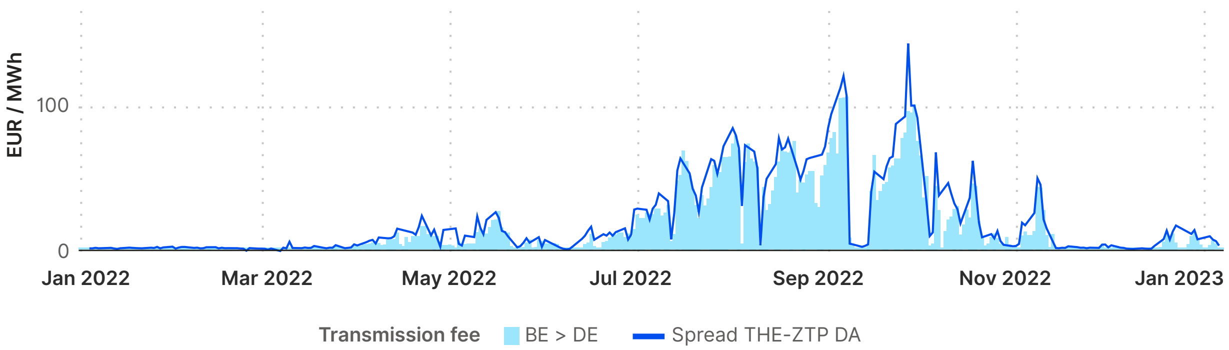
Source: ACER calculation based on PRISMA auction data for 'EUR/MWh'-cost of transmission capacity and ICIS Heren.

Figure 46: Day-ahead hub spread between TTF and PVB hubs and levelized cost of day-ahead transmission capacity from Spain to the Netherlands, via France and Belgium (EUR/MWh) - 2022



Source: ACER calculation based on PRISMA auction data for 'EUR/MWh'-cost of transmission capacity and ICIS Heren.

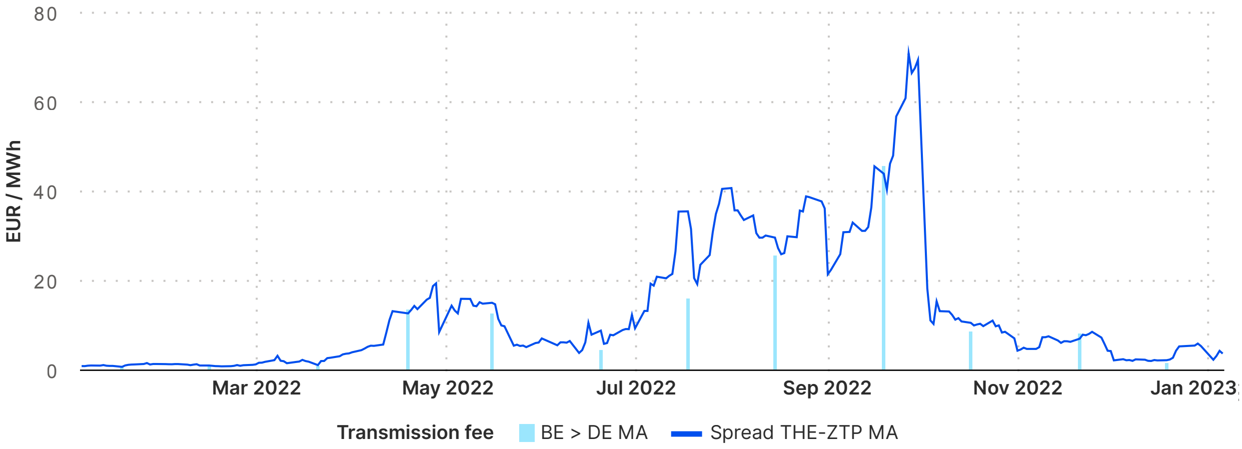
Figure 47: Day-ahead hub spread between THE and ZTP hubs and levelized cost of day-ahead transmission capacity from Belgium to Germany (EUR/MWh) - 2022



Source: ACER calculation based on PRISMA auction data for 'EUR/MWh'-cost of transmission capacity and ICIS Heren.

142 A similar close correlation between the levelized transmission cost and the hub spread between Belgium and Germany (and Belgium and the Netherlands) also holds for the month-ahead hub trading products and month-ahead capacity products. Figure 48 analyses that correlation, taking as a reference the transmission auction dates.

Figure 48: Month-ahead hub spread between THE and ZTP hubs and levelized cost of month-ahead transmission capacity from Belgium to Germany (EUR/MWh) - 2022

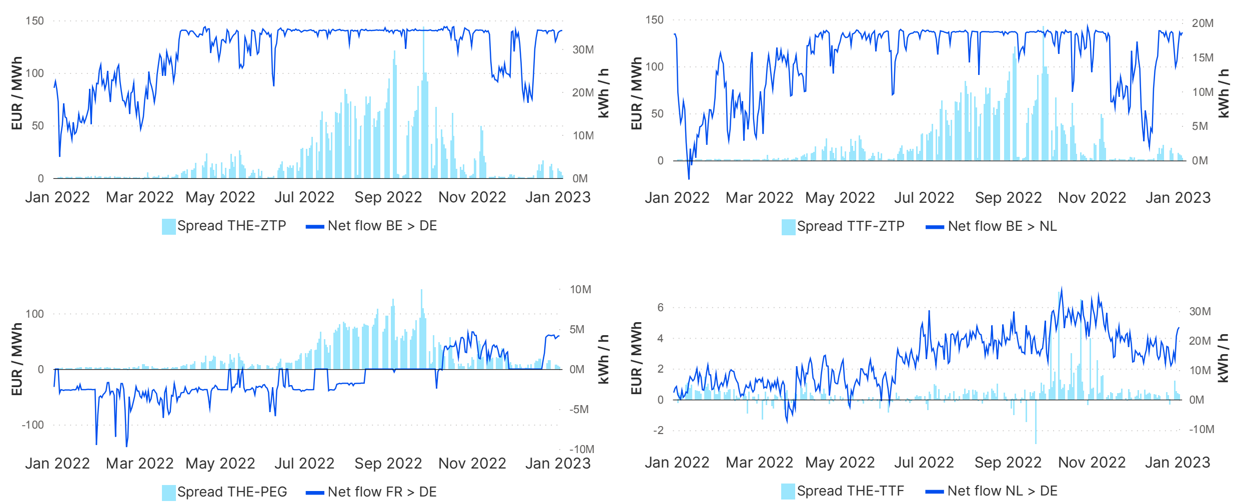


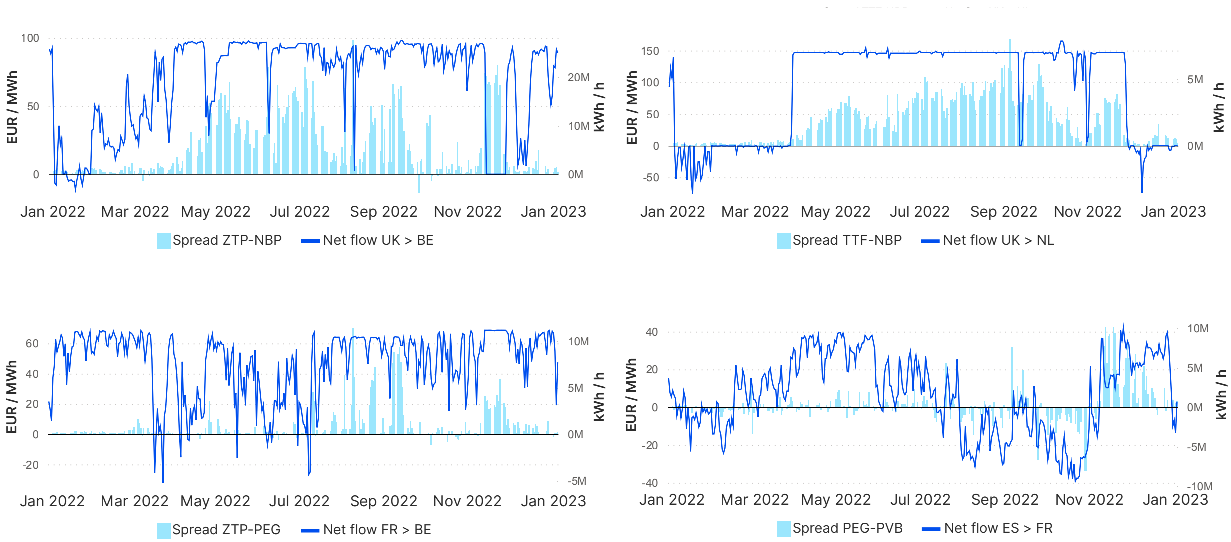
Source: ACER calculation based on PRISMA auction data for 'EUR/MWh'-cost of transmission capacity and ICIS Heren.

Note: transmission capacity costs relate to the day of the auction. Month-ahead firm transmission capacity is auctioned on the third Monday of the month preceding the start of the product.

143 Hub spreads typically act as drivers for gas flows since, in line with economic logic, gas tends to move from lower-priced markets to higher-priced markets. However, as Figure 49 reveals, during the summer of 2022 the extreme magnitude of the hub-spreads lessened in many cases the extent of the correlation between hub spreads and flows. The rationale behind this is that gas flows had already been maximised along the supply routes, irrespective of the exceptionally high levels of hub spreads. Gas flows from Belgium to Germany, and from Belgium to the Netherlands were maximised early on, as well as flows from Norway and from the UK into NWE. Notably, the supply corridor from France to Germany started to operate in October 2022, albeit with limited capacity. Gas flow from Spain to France responded dynamically as well to short-term hub spread signals, with the dominant direction of flows changing several times throughout 2022.

Figure 49: Day-ahead spreads at selected hub-pairs (EUR/MWh) and physical flow between the hubs (kWh/h) - 2022





Source: ACER calculation based on ICIS Heren for hub spreads; ENTSOG TP for flows.

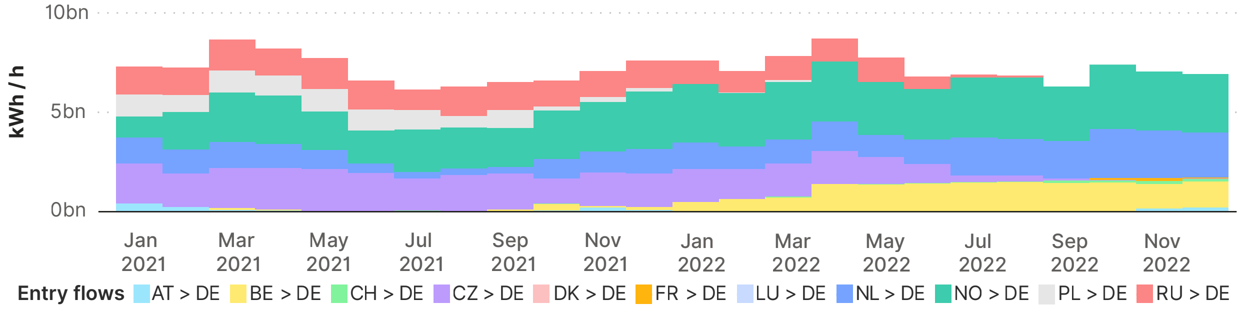
Note: The price spread is positive when the first named hub trades at a premium. Flows were maximised from Belgium to Germany and Belgium to the Netherlands already in the second quarter of 2022; physical flow from France to Germany started in October 2022. The interconnectors between the UK and Belgium ('Interconnector') and the UK and Netherlands ('BBL') were price responsive, and flows was maximised in the direction to the EU throughout the year. Flow at the VIP Pirineos between Spain and France also responded to price signals with flow direction changing according to the prevailing hub spreads that had the French PEG at a premium over the Spanish PVB roughly between March and August and again from around December.

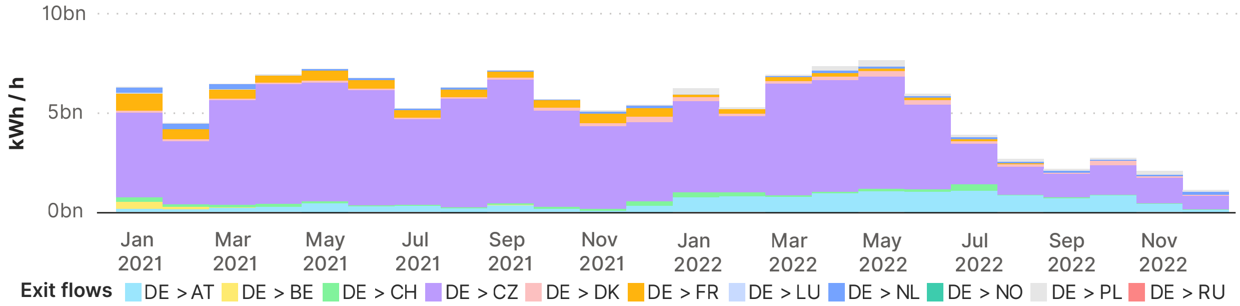
2.5.3. Adaptative response: Maximised network use and competition for scarce resources

TSOs optimised networks use and users competed for scarce capacities.

144 EU gas flow patterns changed substantially in 2022 compared to 2021 to shift away from Russian gas imports. Using Germany as an illustrative example, Figure 50 shows how the most notable flow changes occurred in the summer of 2022. Then, Russian imports drastically ceased and had to be offset with eastern direction flows from neighbouring hubs, namely Belgium and the Netherlands and with rising imports from Norway. Later in the year, from end-autumn direct LNG supply into Germany became possible following the start of operation of new LNG terminals, as Section 2.4. LNG developments discusses. There was also a notable drop in the exit flows from Germany into adjacent markets during the summer of 2022. The flows to the Czech Republic decreased the most. The flow from Germany to France came to a full stop in October 2022, when the physical reverse flows from France to Germany became active. Flows from Germany to Austria increased somewhat in 2022 compared to 2021.

Figure 50: Evolution of gas flow entering (top) and exiting from (bottom) Germany, for main EU borders (kWh/h) - 2022





Source: ACER calculation based on ENTSOG TP.

145 The German initial example exemplifies the challenge and the extent of the flow reconfigurations that were implemented during the summer of 2022. This Section first summarises the coordinated actions that the TSOs took to accommodate the shifting supply routes and to address the rising congestion in North-West Europe. In addition, it discusses how network users changed their booking behaviour in the course of 2022.

TSO actions to optimise gas transmission networks

146 ACER's Special Report on Addressing congestion in North-West European gas markets explores the actions taken by TSOs to optimise their networks. The Report is structured in various case studies, analysing the specific developments in Belgium, France, Germany, and the Netherlands[124].

147 TSOs adapted their network configurations to address a scenario of reduced Russian supplies, increased LNG and pipeline supplies from the West, and reduced domestic consumption. Operationally, capacities were reduced at underused interconnection points and reallocated to the congested routes, particularly after the termination of legacy contracts. Flows were steered towards areas of increasing demand, and compression was temporarily boosted above usual levels to physically push more gas through the pipelines[125].

148 NRAs also contributed with regulatory action to accommodate the adapted network configuration and steer flows. The physical flow of LNG and Norwegian supplies from France to Germany became possible on a firm day-ahead basis after an agreement was reached to reconcile the different odorization practices in both markets. After the German NRA issued a regulatory decision that offered financial assurances against potential damage claims from industrial users, German TSOs started to accept odourised gas from the French system. The French NRA also adapted the internal congestion management procedures within the French market, including the use of locational price spreads, adapting it to the new context. That adjustment assisted the managing of the internal French market area bottleneck, aiding to flow more gas from Spain and from the south of France to the north of the country, where gas supply scarcity was higher.

149 TSOs also worked to enhance a more efficient allocation and use of capacity. While (bundled) firm capacity is not straightforward to increase, TSOs sold large amounts of unbundled interruptible capacity

124 See ACER's Special Report on Addressing congestion in North-West European gas markets.

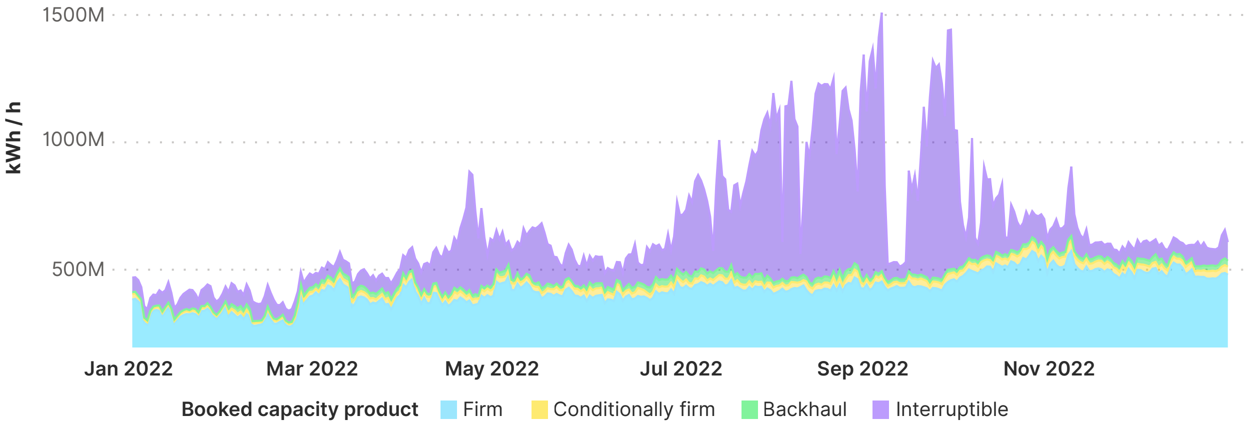
125 Gas transmission capacities are the outcome of considering several gas flow scenarios. When capacity is boosted in one part of the system, it usually means capacity decreases elsewhere in the system. While TSOs must guarantee firm capacity in all possible flow scenarios, they can further optimise the network configuration to accommodate the most likely flow scenarios through non-firm capacities.

in auctions, via *overnomination* procedures. *Overnomination* enables network users to simply declare during the day-ahead and within-day timeframes their interest to flow more gas than their contracted capacity allows; these additional capacities (turning in flows) are then allocated based on actual availability and using a pro-rata approach over all network users.

150 Interruptible capacity products were also extensively used to optimise the sale of capacity. Interruptible capacity helps to improve the efficiency of the network, as it enables TSOs to flow gas up to the technical capacity limits when parts of the firm capacity remain unused.

151 Figure 51 illustrates the evolution of the contracted capacities according to the booking products' firmness, distinguishing firm, conditionally firm, (virtual) backhaul[126] and interruptible capacity.

Figure 51: Evolution of total booked transmission capacity at all EU interconnection points by product firmness (kWh/h) - 2022



Source: ACER calculation based on auction data from GSA Platform, PRISMA and RBP.

Note: the graph does not depict capacity that has been contracted outside of auction procedures or was booked before 1 January 2021.

152 TSOs in Germany and the Netherlands offered unlimited interruptible capacities. That resulted in very high contracted volumes albeit detached from actual physical flow capabilities. Network users booked massive interruptible capacity to express their willingness to pay for the capacity acquisition. In practice, as interruptions were implemented proportionally, and in view of the high levels of interruption occurring as the system approached its capacity limits, users who contracted greater capacity were assigned a proportionally larger share of capacity to facilitate gas flow. As of May 2022, German TSOs began aligning their interruptible capacity offerings with physical realities. This adjustment allowed network users to express their willingness to pay through auction premiums. Meanwhile, in the Netherlands, both the TSO and the National Regulatory Authority have acknowledged the inefficiency of offering volumes that were disconnected from the physical network conditions, and they are considering a shift towards offering interruptible capacities that better reflect the actual physical network conditions.

153 In addition to maximising the capacities with the existing gas system elements, the transmission bottlenecks were also addressed by strategic investments in additional and new LNG terminal capacities. As discussed in Section 2.4. LNG developments, these investments proved very effective and were managed, augmenting LNG supply to various EU gas markets in record time[127].

154 In terms of pipeline capacity investment, for instance, Belgium approved an internal reinforcement between Desteldonk (~Ghent) and Opwijk (~Brussels). The project started construction in March 2023, addresses security of supply and is part of Belgium's hydrogen strategy. It would also support maintaining an increased flow of gas from Belgium to Germany. If it goes further, the second stage of the project would be reinforcing the Zeebrugge to Evergem (~Ghent) pipeline section and it is being planned.

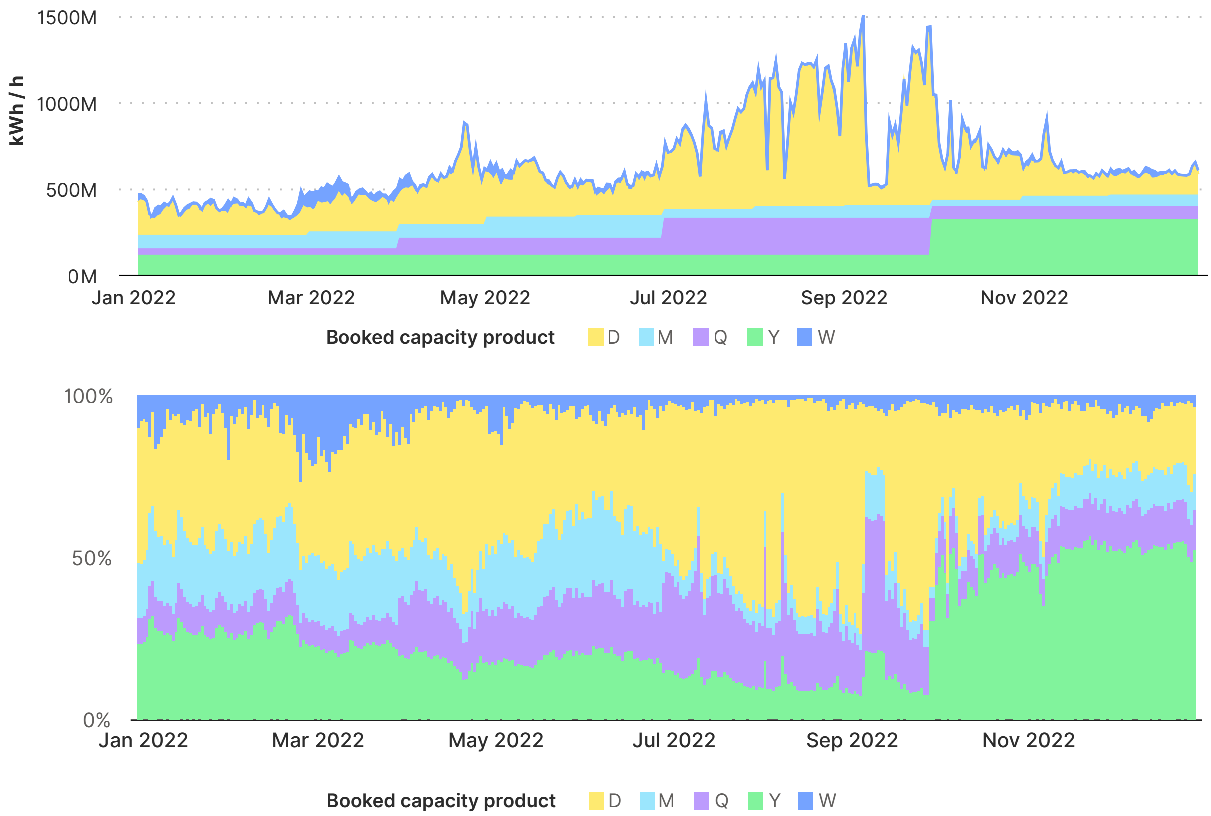
126 Backhaul means that virtual flow happens in the opposite direction of the dominant physical flow; the commercial flows are netted and that net flow occurs in the dominant flow direction. The use of backhaul capacity depends on the presence of the physical flow; if there is insufficient flow, the backhaul condition is not met and the capacity cannot be used.

127 The Danish NRA signals that entry capacity from Denmark to Germany was reduced substantially by unilateral decision of the German TSO after the introduction of the LNG FSRU terminals at Brunsbüttel and Stade, both in Germany. The unilateral reduction of cross-border capacity goes against ACER's recommendation that Neighbouring TSOs must extensively coordinate and jointly maximise the availability of firm and interruptible capacities at their interconnection points.

Network users competed for scarce capacities

155 During the summer of 2022, network users faced fierce competition when attempting to book scarce capacities on key supply routes. This heightened competition prompted a shift towards extending the durations of capacity contracts, to secure the option-value of the transmission capacity during more time. As Figure 52 analyses, the capacity products of yearly and quarterly duration were booked significantly more in 2022 than in 2021. The larger bookings of these two products reduced in turn the residual capacity offered for the shorter-term monthly, daily, and within-day timeframes, as the technical capacity remains unchanged until capacity-increasing investment materialise.

Figure 52: Evolution of total booked transmission capacity at EU interconnection points by product duration (kWh/h) - 2022



Source: ACER calculation based on auction data from GSA Platform, PRISMA and RBP.

Note: the graph does not depict capacity that has been contracted outside of auction procedures (e.g. capacity booked via the overnomination procedure) or was booked before 1 January 2021.

2.5.4. Lessons learnt: upgrading needed to align with the new flow reality

156 The EU's integrated gas system proved to be overall resilient to the market shock occurring during the summer of 2022. An adaptive system management facilitated the reconfiguration of supply and demand, ensuring gas would flow to where demand was higher within the technical limits of the transmission networks.

157 Nevertheless, the system necessitates a certain upgrading to align with the evolving flow reality. Therefore, addressing the most acute supply bottlenecks presents a no-regret measure to help bring down spreads between the different gas hubs in Europe. ACER reiterates four key recommendations from ACER's Special Report in dealing with congestion:

- Neighbouring TSOs must extensively coordinate and jointly maximise the availability of firm and interruptible capacities;
- Neighbouring NRAs must extensively coordinate and remove any regulatory obstacles that prevent the optimal use of the existing network for the reconfigured supply routes;

- TSOs must carefully consider if investment is needed where physical bottlenecks remain after the operational optimisation of the existing network and considering whether the bottlenecks would be prevailing over a relevant period;
- NRAs shall carefully assess the appropriateness of investment that removes structural bottlenecks considering the Union's energy and climate policies, and security of supply while mitigating the potential of future asset stranding. Congestion revenues may be used to finance such network investment.

2.6. Driver 6: Trading developments

2.6.1. Driver relevance: trading plays a central role in establishing gas prices

158 Trading plays a central role in establishing the price of natural gas at European markets. Trading activity enables buyers and sellers to negotiate contract conditions and to effectively manage volumes, thus contributing to determining the market equilibrium.

159 In Europe gas trading primarily occurs at the so-called gas hubs, which can be defined as virtual trading points linked to specific market areas. Gas hubs facilitate the buying and selling of gas. Moreover, they are crucial for the technical management of the system. Electronic trading platforms, such as commodity exchanges or over-the-counter brokered trading venues, are commonly associated with gas hubs, enabling the price discovery and the actual transaction of contracts. Additionally, gas hub operators assess the net physical positions resulting from trading activities and implement the related transfer of rights. This information will be used as key input by the technical system manager when managing the gas system.

160 The concept of hub liquidity is crucial. It overall refers to the volume of the transactions taking place at the trading platforms, and more specifically, relates to the ease of trading of gas contracts without causing significant price fluctuations. Higher liquidity strengthens a more efficient and competitive price formation, while reduces the impact of specific trades or market actors on prices. Importantly, high liquidity beyond the spot market allows market participants to hedge their prices and volumes for future delivery, thereby managing risks associated with their gas portfolios.

161 Finally, gas hubs contribute to enabling the integration of the different gas markets within the EU. This is because market participants can access and trade gas across multiple hubs, facilitating the transfer of gas between markets and optimizing the price differences and the overall supply and demand.

162 The more recent gas hub trading and pricing model coexists with the more traditional long-term and bilateral contracting model. Both form a dual model for physical gas contracting and sourcing in the EU. Notably, the prices of the contracts traded at gas hubs are increasingly used as benchmarks for indexing the prices of long-term natural gas supply contracts, intertwining both elements.

163 The exponential rise of the hub trading model over the past ten years has been driven by its ability to optimize gas procurement for market participants and accommodate the flexible supply and price discovery requirements of final consumers. As gas trading hubs have matured, they have attracted more producers and buyers, leading to a gradual shift away from bilateral long-term contracts in favor of direct hub trading. The active participation of financial players in the market has further bolstered this trend. Notably, in the North-West region, the Dutch TTF has emerged as the European reference hub, with for example North Sea producers actively engaging in direct gas sales on trading platforms. However, the greater reliance on the shorter-term and more dynamic hub procurement model arguably made gas prices more susceptible to the factors that resulted in exceptionally high gas prices during the summer of 2022.

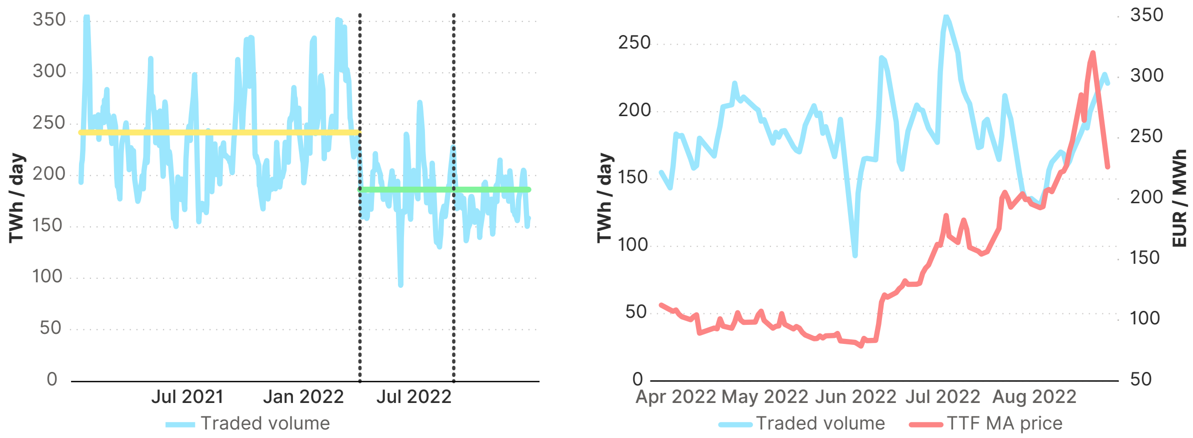
2.6.2. Overview of summer 2022: trading activity persisted despite challenges

164 The Russian invasion of Ukraine and the ensuing uncertainty about gas supply negatively affected the liquidity of EU gas hubs in 2022. For instance, the aggregate trading volumes (i.e., trading volumes across all EU gas hubs, including all energy exchange and gas brokered contract maturities) decreased from an average of circa 250 TWh per day prior to the invasion to less than 170 TWh per day from April 2022 to the end of 2022. However, once trading volumes dropped to this lower level in April 2022, they

remained relatively consistent throughout. This includes from mid-June through to August 2022, when the prices of the benchmark TTF month-ahead products quadrupled as shown in the left panel of Figure 53.

165 In the period when gas hub prices reached the record highs, which occurred from 9 to 26 August 2022, trading volumes also increased as shown in the right panel of Figure 53. This implies that the gas hub price spike cannot be associated with thinned-out market trading activity. However, several indicators point toward a more challenging trading environment during that period. For instance, the increase of the bid-ask spread on the brokered market (see Figure 55) indicates that that segment of the market was under stress. Moreover, on the exchange segment, ESMA's analysis finds that margins posted at commodities central counterparty clearing houses (CCPs) increased by approximately 30% in August 2022.

Figure 53: European natural gas volumes traded at exchanges and brokers (TWh/day) - 2021 - 2022 (left), and European natural gas volumes traded at exchanges and brokers and TTF month-ahead price (TWh/day) (EUR/MWh) (right) – April 2022 – August 2022



Source: ACER calculation based on REMIT and ICIS data.

Note: Options and swaps are excluded from trading data.

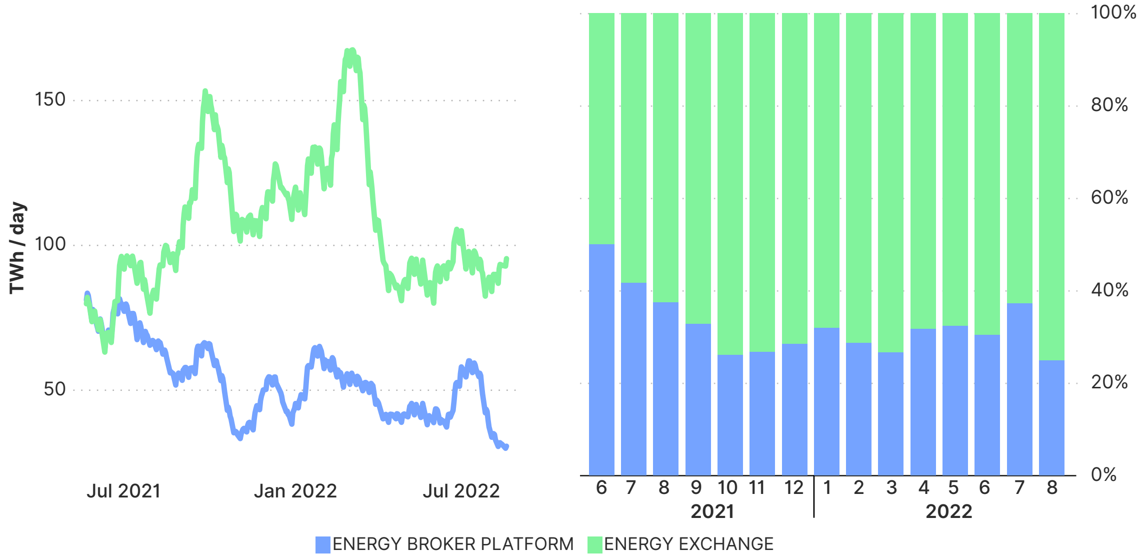
166 Several trading developments unfolded as a consequence and/or as an adaptation by market participants to the perceived risks and increasing price volatility during summer 2022. These developments are described in more detail in the paragraphs below and include:

- A partial shift of trading activity from the brokered, over-the-counter market to the exchange spot and futures market;
- The relative increase in trading activity of selected European gas hubs where prices had diverged from TTF prices;
- and changes in margin rates for exchange traded contracts.

167 After the EU gas market liberalisation, and following the establishment of the entry-exit systems and virtual gas hubs, European gas trading was predominantly based on over-the-counter brokered contracts. Natural gas futures contracts were offered at exchanges, but they initially did not gain significant traction. The notable exception were the natural gas futures traded for delivery on the NBP hub in the UK.

168 TTF futures trading witnessed notable growth in 2016, and then entered a phase of exceptional expansion in 2018. The surge in TTF futures trade eventually led to exchange-based gas traded volumes surpassing over-the-counter brokered trading volumes in the third quarter of 2021, as shown in the left panel of Figure 54. Notably, during August 2022, the estimated share of the over-the-counter brokered trading volumes hit a low, falling below 25% as shown in the right panel of Figure 54.

Figure 54: Evolution of brokered and exchange natural gas traded volumes (TWh/day) (left) and the relative share (%) of brokered and exchange natural gas traded volumes (right) – all EU gas hubs - June 2021 – August 2022

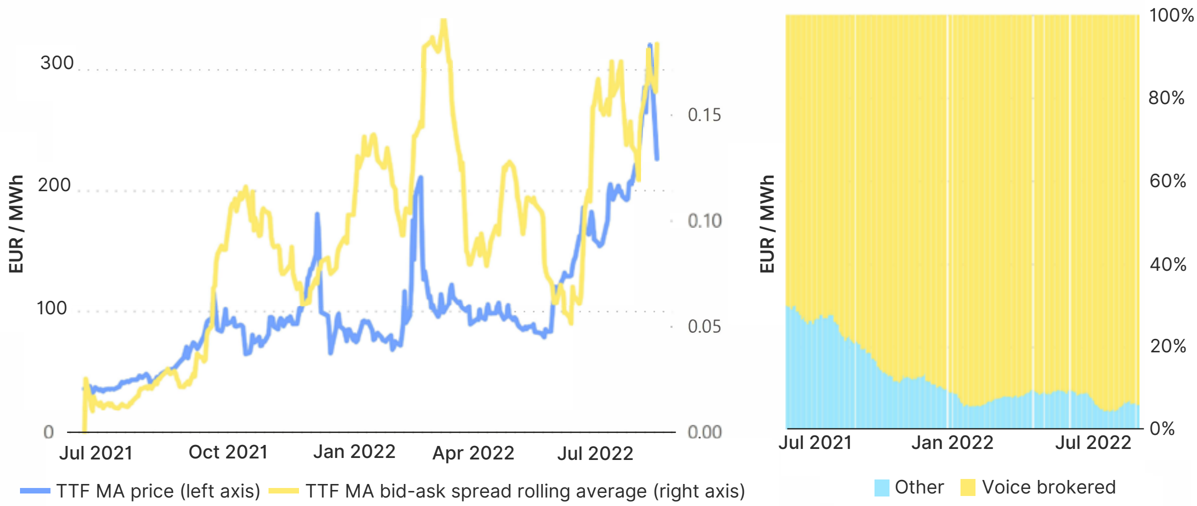


Source: ACER calculation based on REMIT data.

Note: Options and swaps are excluded from trading data.

169 ACER understands that one of the reasons for the substantial fall in over-the-counter brokered transactions in summer 2022 was the exhaustion of counterparty credit limits amongst market participants. As the left panel of Figure 55 shows, the proportion of over-the-counter volumes which were voice brokered increased to an estimated 95% during summer 2022. This indicates that active brokerage was necessary to conclude transactions and that the possibility to trade contracts offered electronically by brokers was severely constrained.

Figure 55: TTF month-ahead price and bid-ask spread (left) and the estimated split between electronically and voice brokered over-the-counter trading volumes (right) – July 2021 – August 2022



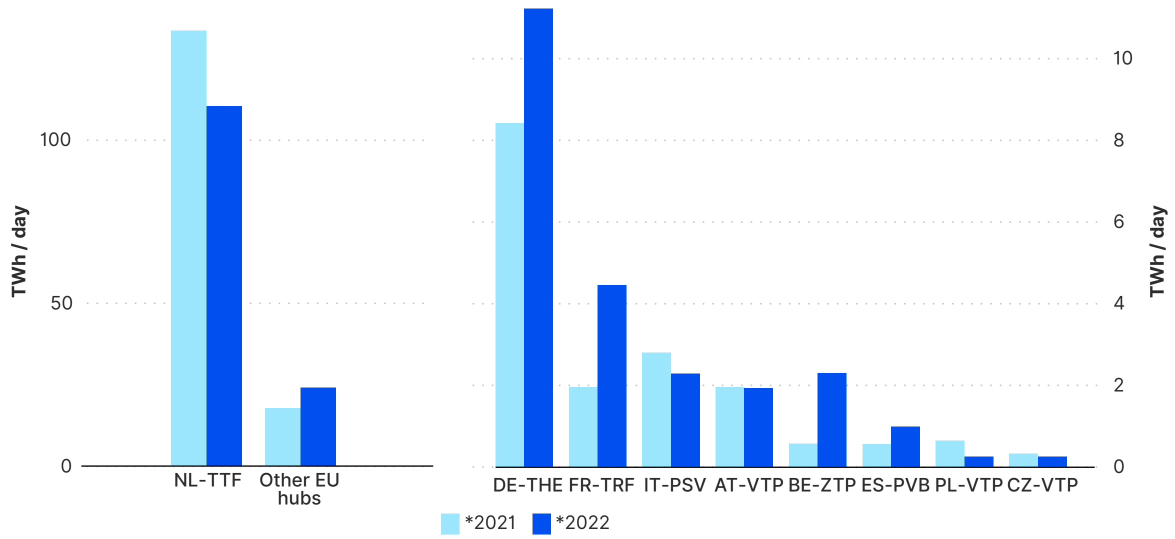
Source: ACER calculation based on REMIT and ICIS data.

Note: Options and swaps are excluded from trading data.

170 The relatively high and consistent levels of price convergence and correlation among EU gas hubs, which had been the norm for several years and especially in NWE, underpinned the emergence of the TTF hub in the Netherlands as the de-facto EU natural gas forward market. The low and consistent spreads between TTF and other EU hubs minimised the perceived basis risk of trading TTF contracts to hedge physical gas exposure outside of the Netherlands.

171 However, hub price convergence and correlation levels were severely disrupted during summer 2022, as Section 2.5 discusses. Locational spreads leapt immediately after the Russian invasion of Ukraine and then grew to levels above 100 EUR/MWh on multiple occasions across the third quarter of 2022. Price disparities became evident between those gas markets where LNG import capacity and other sources of non-Russian natural gas supply were greater than consumption demand, storage-injections related demand and export capacity (e.g. Spain, France, Belgium) and markets where this was not the case (e.g. the Netherlands, Germany or Austria and to a minor extent, Italy). The price divergence compromised the strategy of using TTF as a proxy hedge. This is, buying or hedging gas at TTF prices, but selling on or at local hub prices (for example this was the case in markets such as France, where the referential PEG hub price was significantly lower than the TTF price). Possibly as an adaptation by market participants to the higher basis risk described above, trading activity at some gas hubs increased as Figure 56 shows. However, this neither offset the year-on-year drop of TTF trading volumes nor incepted the emergence of a hub that would offer an alternative to the TTF as an EU gas forward market.

Figure 56: Average Summer* daily trading volumes – 2021 - 2022



Source: ACER calculation based on REMIT data.

*Note: Options and swaps are excluded from trading data. * Based on transactions in July and August.*

172 In parallel with ACER's analysis of the natural gas price drivers, ESMA investigated the functioning of the natural gas derivatives market during the summer of 2022. Due to its relevance and complementary nature to ACER's own analysis, a summary of ESMA's main findings is included in this report.

ESMA's findings regarding the functioning of the natural gas derivatives market during August 2022[128]

ESMA investigation scrutinises the developments in the Dutch natural gas futures market (TTF) across August 2022. The assessment makes use of trading activity and trade state data[129] reported to ESMA in compliance with the European Market Infrastructure Regulation (EMIR), alongside data gathered from central clearing counterparties[130]. In places, ESMA uses August 2021 and March 2022 as relevant periods to benchmark indicator values obtained for August 2022. ESMA's analysis primarily focuses on three aspects: liquidity shifts in the TTF futures market, alterations in CCPs' margins, and shifts in trading behaviour among maker participants.

Liquidity

ESMA finds that the TTF derivatives market did not experience a severe or unprecedented loss of liquidity during the August 2022 price spike. This is in line with ACER's findings regarding the overall liquidity of the natural gas wholesale market, with the caveat that the brokered forward natural gas market, which is out of scope of MiFID II hence not part of ESMA's analysis[131], may have been relatively more strained than the TTF futures market.

ESMA finds no evidence of reductions in TTF futures positions during August and September 2022. Furthermore, TTF futures traded volumes in August 2022 were only slightly down compared with August 2021 when measured in MWh and despite much higher prices. This trend shows the inelasticity of demand amid pressures to secure winter supply. For instance, a positive correlation between end-client buying volumes and prices shows demand grew even as prices surged.

ESMA finds that liquidity measures such as the bid-ask spread were impacted in August 2022. However, this was not unprecedented. ESMA finds that both price volatility and liquidity were comparatively more highly impacted by the relatively lower price surge following the Russian invasion of Ukraine in February 2022. In other words, despite the record prices in August, ESMA does not find extreme volatility or illiquidity in the TTF derivatives market during the summer 2022 period.

CCPs and margins

ESMA finds that during March and August 2022, the higher hub price levels and volatility were incorporated in the CCPs TTF derivatives margin calculation. For instance, the initial margins posted at commodities CCPs increased by approximately 30% from 1 to 26 August 2022. The margins were met on time.

128 Report on Trends, Risks and Vulnerabilities: The August 2022 surge in the price of natural gas futures.

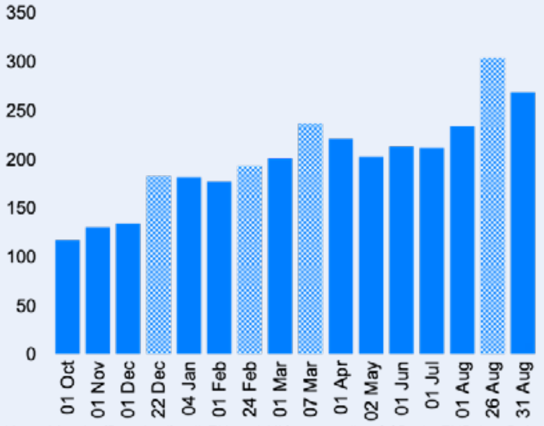
129 ESMA notes that there are several important limitations relating to the EMIR data used. For instance, EMIR data is only reported where at least one counterparty is domiciled in the EEA, therefore much of the analysis is based on a partial sample of counterparties in the market because it does not include trades that involve two non-EEA counterparties.

130 With respect to EMIR and CCP data used in the margin analysis, ESMA notes the following limitations in usage of the data: firstly, the data shows margins at the level of clearing members (mostly financial counterparties) but lacks information on the level of clients and non-financial counterparties (NFCs). Secondly, data is not granular enough to distinguish the exact impact on TTF based derivatives as netting is applied across different products.

131 Those instruments (wholesale energy products traded on an OTF that must be physically settled) are not classified as financial instruments as per Annex I Section C(6) of MiFID II. Hence transactions in those instruments are not reported under any financial regulation in ESMA's remit.

Margins required all EU and UK commodities CCPs

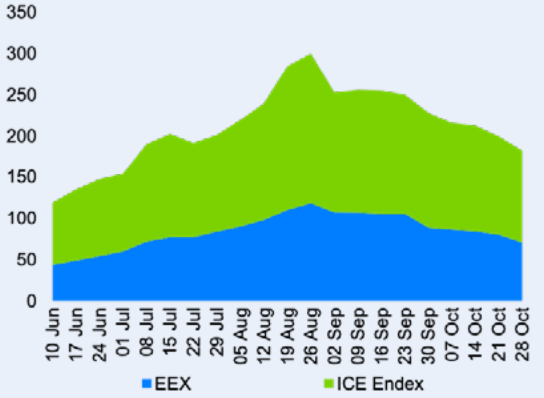
Margins responded to price and volatility



Note: Margin (Required), all EU and UK commodity CCPs in EUR bn. Paler columns represent periods when margins peaked.
Sources: Margin data submitted by EU and TC CCPs, ESMA.

Cleared natural gas futures positions

Grew and later fell with prices



Note: Outstanding notional amounts in natural gas futures, cleared and excluding intragroup, executed at ICE Endex (MIC: NDEX) and EEX (MICs XEER, XPOW and XPSF) in EUR bn.
Sources: EMIR, ESMA.

Higher margins could have been associated with lower on-exchange trading activity because this form of execution is more costly and has greater liquidity needs to hold positions. Clearly, market participants did experience a difficult market environment during the August 2022 market events. Nonetheless, and from the EMIR data investigated, there is no evidence that a reduction in Exchange Traded Derivatives (ETD) position happened nor that price formation was impacted during the August 2022 market events.

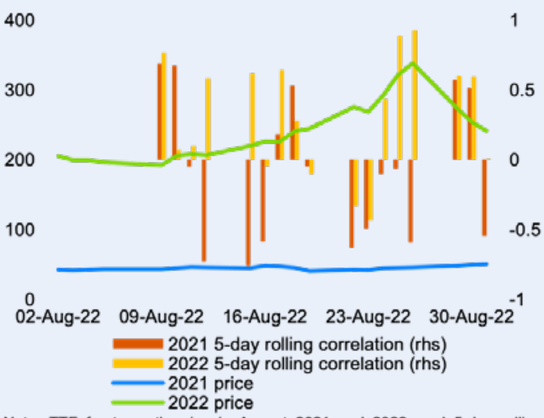
A potential explanation for the continuous high level of activity would be that exchange trading provide for a more liquid exit point and higher price transparency during a market crisis than OTC trading. That being said, there is strong evidence of reduced ETD positions and increased OTC share in the following months that could potentially be linked to increased margin requirements on TTF contracts.

Trading behaviour

ESMA finds that in August 2022, there was a positive correlation between daily traded volumes and price (0.35, as compared to a negative correlation (0.32) over August 2021). Moreover, the correlation between price and volumes was particularly positive during the week of 23 August when prices dramatically surged. The sharp increase in price-volume correlation through the week of the 23 August, shows just how strong the demand-side momentum was at that point in time, indicative of a strong willingness (in the aggregate) to keep buying despite rising prices, in turn indicative of short-term expectations of continuing limited supply and continuing rising prices.

Prices and correlations with volumes, 2022 vs 2021

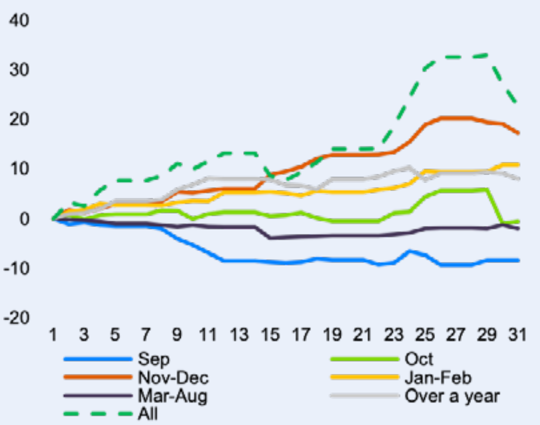
Positive correlation through much of August 2022



Note: TTF front month price in August 2021 and 2022, and 5-day rolling correlation between price and daily end-client volumes. 2021 values are for the corresponding working day in August 2021.
Sources: EIKON Refinitiv, TRs, ESMA.

Accumulated net positions by maturity in August 2022

Demand focused on maturities covering winter



Note: Total net long / short positions accumulated in TTF futures through August 2022 by period of first delivery month, in MWh millions. Net long is positive, net short is negative.
Sources: EIKON Refinitiv, TRs, ESMA.

At the counterparty level, looking at end-clients with the largest accumulated net positions over August 2022, ESMA's analysis reveals several notable trading behaviours:

1 Unlike in August 2021, in August 2022 end-clients in EU member states generally accumulated long positions, with demand focused on maturities before and in winter.

2 Big energy producers were net sellers across most maturities over the month, showing a role in bringing supply.

3 Among the most active firms, electricity utilities showed two main patterns, a first buying maturities for the winter away selling others, and a second accumulating long positions across maturities, sometimes in large jumps. The latter more likely impacted price and strained liquidity.

4 Non-end clients (clearing members, market makers) mostly sold in August, accumulating short positions in serving demand from end clients.

In conclusion, and based on the available EMIR data, ESMA observes that the price surge appears to have primarily stemmed from robust demand among EU end-clients, driven by the necessity to secure winter reserves amid a decrease in Russian supply.

2.6.3. Adaptive response: reshaped trading products and venues

173 The surge in EU gas prices elicited adaptive responses from market participants, leading to a reassessment of gas product types, trading venues, and trading conditions. Furthermore, in response to the enduring price surge, a coordinated emergency regulation introducing limits to the price of derivative products was implemented at EU level.

174 Market participants' initial adaptation can be traced to the surge of gas and electricity prices in autumn 2021. As previously stated, a move away from brokered trading towards centrally cleared exchange trading accelerated in that period[132]. At that stage, the migration of trading activity to exchange trading venues appears to have been motivated by the perceived risk of possible counterparty default, against which centrally cleared exchange trading provides a more effective mitigation[133]. Furthermore, with prices persisting at high levels, market participants seemed to have largely exhausted bilateral credit limits with most counterparties, which again favoured exchange trading.

175 However, after the price surge of August 2022, the combination of higher hub prices and higher initial and variation margins rates resulted in increased financing liquidity requirements to enter into and/or hold centrally cleared positions[134]. This is deemed to have contributed to a decrease in natural gas derivatives positions resulting from exchange trade, while notional amounts of OTC traded derivatives positions remained relatively consistent.

176 During and after summer 2022, various MSs provided emergency financing liquidity assistance to support market participants in managing the rising margin requirements stemming from previously established futures' positions. That public support was offered in the form of financial guarantees, or similar measures[135]. For instance, support measures backed electricity generators having previously sold their expected output (i.e., hedged future production) to meet margin calls and maintain their positions.

177 Simultaneously, some market participants chose to gradually trade higher volumes locally at markets where prices significantly diverged from TTF prices. This shift allowed them to better and locally align their physical gas exposure. The strategic shift marked a departure from past years' trend of relying

132 For more details see 'Long-term contract volume shares in 2021' in REMIT Quarterly, Issue No. 27 / Q4 2021.

133 For more details see Central Counterparty Clearing Houses and Financial Stability.

134 For context, the prices of exchange-traded products surged up to 10 times their historical 2017-2020 average prices during the summer of 2022. Meanwhile, margin requirements in some cases increased by two to three times. This combination necessitated a corresponding increase in financial requirements to cover similar trading positions.

135 For more details see ACER's inventory of emergency measures implemented by MSs.

more and more on TTF as a proxy forward market (i.e., relying on TTF as a proxy market instead of trading locally carried implicit a basis risk. Yet, TTF was favoured in view of its rising liquidity and its EU benchmark character). The divergence between TTF and some other European gas hubs prices such as NBP, PEG and PVB during the summer of 2022 resulted in the sudden materialisation of the price risk incurred when hedging exposure at neighbouring gas hubs. Nonetheless, the lower liquidity of European gas hubs relative to TTF resulted in a significant reversal of this trend once gas hub prices started to converge again. That stronger hub price convergence may have also lessened speculative price-arbitrage trading between adjacent hubs.

178 In terms of policy response at the European level, the EU council adopted two emergency regulations that are – in part or fully – aimed at adapting certain rules governing natural gas trading: the Regulation (EU) 2022/2576 enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders; and regulation (EU) 2022/2578 establishing a market correction mechanism to protect Union citizens and the economy against excessively high prices (MCM)[136]. The former regulation establishes that trading venues on which energy-related commodity derivatives are traded should set up temporary intra-day volatility management mechanisms[137]. This obligation is established in addition to the already existing obligation for trading venues to have in place circuit breakers to temporarily halt or constrain trading in case of significant price movements introduced by the Markets in Financial Instruments Directive (MiFID II). The latter regulation (MCM) defines triggering conditions for the entry into force of a temporary price ceiling at which gas derivatives based on virtual trading points with maturities between month-ahead and year-ahead can be traded. Both regulations were adopted in December 2022 and are in force for a period of one year. At the time of publication, the market correction mechanism has not yet been activated with the relevant gas prices significantly below triggering levels.

2.6.4. Lessons learnt: fair trading activity remains crucial

179 The organized trading market for natural gas underwent a turbulent period in 2022. The turbulence reflected the difficulties and uncertainties caused by the substantial loss of Russian pipeline gas supply, with shortages widely perceived as a realistic possibility for the coming winter. Despite attracting suspicion and scrutiny amidst the energy crisis, organized trading markets played an important role in the rebalancing of the European gas market. By incentivizing demand reduction, attracting alternative supply and sending signals about needed gas infrastructure improvement – from transportation network optimisation to investments in new gas-related facilities – market prices amplified the urgency to act and rewarded those that were able to do so. Yet, it remains crucial for market participants and policymakers to maintain vigilance in order to ensure and advance fair trading conditions, while comprehending the implications of the evolving trading framework.

136 See footnote 1.

137 For more details see ESMA's Final Report on Intra-day Volatility Management Mechanism.

Annexes: Back-up tables.

Table 2: Changes in LNG capacity offered capacity in 2021-23.

	Additional offered capacity and considerations
Belgium	In the Zeebruge LNG terminal, Fluxys in collaboration with shippers were able to increase the number of offered slots from 110 to 123 for 2022. These slots were auctioned to the market. For 2023, additional slots can be offered.
Croatia	In April 2022, the LNG operator informed about the increase in the technical capacity of the LNG Terminal. The maximum capacity of LNG regasification increased from 300.000 m3/hour (2,96 bcm/y) to 338.000 m3/hour (2,9 bcm/y). Link. Additional LNG regasification capacity was offered to interested users in accordance with the Rules of Operation (Official Gazette 87/21, 72/22) in the Annual Capacity Booking procedure for the gas year 2022/2023 and the following gas years, as well as the short-term regasification capacity in the Short-Term LNG Regasification Capacity Booking procedure from 1st May 2022 until the end of the current gas year. Currently, terminal capacities are fully booked upon the gas year 2036/2037, on LT basis for all users (link)
France	At the Fos Cavaou regulated LNG terminal, the regasification capacity was increased from 274 GWh/day in 2022 to 310 GWh/day in 2023, thanks to a technical debottlenecking of the terminal and the transport network, conducted since May 2022. A further increase is expected in 2024 to 320 GWh/day. This would represent a capacity increase of 46 GWh/day (+17%) between 2022 and 2024. At the (exempted) terminal in Dunkerque, capacity was increased by 80 GWh/day from September 2022 thanks to adaptations on the terminal and transmission network.
Greece	The regasification capacity of Revithoussa (as well as the capacity of the entry point Agia Triada) was increased from 1.000 to 1.400 m3 LNG/h since 1 June 2022. This is a long-planned upgrade (since the 2013-2022 TYNDP). Works were completed in 2018 but then the electric MV line could not support the new installation and we had to wait until 2022 for an upgrade of the electric system)
Italy	The Adriatic LNG offshore terminal has increased its maximum capacity through optimisation, with no physical capacity expansion, by 1 bcm, to increase the offered slots.
Lithuania	There was no additional LNG capacity offered at Klaipeda during 2022-2023. The LNG terminal offers all the regasification capacity for the mentioned period on three different grounds: i) Long-term capacity; ii) Annual capacity; iii) Spot capacity (if technically available).
Netherlands	Per October 1 2022, Uniper has booked extra LNG capacity at Gate terminal. This was made possible through optimization without significant further investment.
Spain	The number of slots offered (and booked) has significantly increased during the last years, due to several reasons, such as the optimization of the capacity derived from the joint management of the terminals under the virtual LNG tank model, the increase of the exports of natural gas from Spain to France via VIP Pirineos, which historically was only used for importing gas from France but this is no longer the case, and the reduction of the imports of gas from Algeria via Tarifa interconnection. The number of slots offered for gas year 2021-22 was 260, while the number of slots offered for gas year 2022-23 reached 372, which means an increase of 43% in the capacity offered.
Poland	Since January 2022 the regasification capacity has been increased to 712500 m3/h due to the commissioning of two new SCV vaporisers (annual send-out capacity is 6,2 bcm). In addition, the construction of a third LNG tank is under way, which will allow for a further LNG terminal capacity increase from 2024 (up to approx. 8,3 bcm annually).
Portugal	LNG regasification capacity offered on a firm basis has been constant at 200 GWh/d over the period from gas year 2018/2019 until 2023/2024. This capacity of 200 GWh/d has been fully booked in the annual auction process since gas year 2019/2020.On top of this firm capacity, additional capacity is available through an interruptible product for the within-day time frame, offering non-utilized capacity. This interruptible capacity product has been in place since 1 October 2020. While firm offered capacity of 200 GWh/d had been fully booked in the annual auction, the additional interruptible capacity being offered has been: 27,6 GWh/d (gas year 2021/2022), 62,9 GWh/d (gas year 2022/2023 until 15-August). The booking of this interruptible capacity has been rather low: 0,2 GWh/d (gas year 2021/2022) and 0,3 GWh/d (gas year 2022/2023 until 15-August). The product resulted in limited additional bookings that were only possible due to the underutilisation of the terminal.

Table 3: Congestion and auction premia at EU import terminals during 2021-23.

	Congestion and auction premia at EU import terminals. Values and considerations.
Belgium	Fluxys LNG regulatory account increased from EUR71m in 2021 to EUR111m by the end of 2022. This was the result of EUR58m over-recovery from LNG services and -EUR20m revenue allocated via transmission tariffs during 2022. In addition, Fluxys LNG recovered additional EUR142m of congestion rent. The total regulatory account at the end of 2022 stood at EUR253m. (link).
France	Several of the latest auctions organised at French regulated terminals for capacity in 2023 led to 5 allocations with premium: 4 unloading schedules of 500 TWh (for each quarter in 2023) at Fos Tonkin were sold in October 2022, one unloading schedule (1 TWh) in June 2023 at Fos Cavaou was sold in May 2023. Yet, contractual congestion did not materialise at all auctions: while some auctions were successful in allocating available capacity without overdemand, others were unsuccessful.
Greece	During the 2019-2022 regulatory period, the Revithoussa LNG Terminal had an over recovery of 14,4 mil.€. Moreover, during the annual auctions that took place in October 2022 for LNG cargo slots/ storage capacity/regasification capacity during 2023, resulted in premia of 38.5mil. for the Terminal (plus 21.5mil. € of premia for its entry point to the System).
Italy	There has been a significant increase in the allocated capacity with respect to 2021 for all the terminals (around +30%). The average price paid for such capacity has indeed increased (on average, +150% higher than the average prices resulting from 2021 auctions) but, given that historically these prices have been quite low, the increase has not been enough to cover for the allowed revenues for all the terminals. On average, the actual revenue has been 30% lower than the allowed revenue, except for one terminal with very low allowed revenue, which has been able to recover revenue +40% higher than its allowed revenue.
Lithuania	Congestion occurred for the long-term (10 years) and annual capacity allocation procedures in 2022. The demand for long-term LNG regasification capacity was significantly higher than the offered capacity in 2022. However, a premia has not been used during the allocation of capacity for 2023. Congestion was managed based on proportionality principle established in the LNG terminal Regulations. On August 2023, congestion management procedures based on market premia were introduced. The operator of the LNG terminal plans to start Long-term capacity allocation procedure based on updated congestion management principles later in 2023.
Netherlands	There was no congestion on the LNG-entry points. The limiting factor was the send out capacity of the terminals. The LNG terminals are exempted from tariff regulation, so no congestion rents or auction premia were recovered.
Spain	There has been congestions for both, slots and LNG storages capacity, but not for the regasification service. The data for 2021-21 shows: Congestion on slots. The average premium during gas year allocation processes was 1 311 355,64 €/slot (1,3 million €/slot), that is, 25,6 times the fix term of the unloading tariff for XL size vessels, according to the values of the tariffs applicable in gas year 2021 - 2022 (the average premium in the previous year was 4.4 times the fix term). The maximum premium reached 7.540.700,42 €/slot and took place in the procedure held in July 2022, for the allocation of the capacity corresponding to the month of August 2022. Congestion on LNG storage. In October 2021 and during the last part of the gas year, there was greater interest for LNG storage capacity and premia began to occur. Specifically, in August 2022, interest in contracting this service skyrocketed, reaching the maximum number of rounds allowed by the legislation (20), with a maximum premium of 0,057538 €/kWh/day/y. This situation was maintained in the auctions held in September for both, monthly and quarterly products. Additionally, daily product auctions were also closed with a premium during the month of September 2022.
Portugal	Congestion has occurred for (1) regasification and for (2) storage of LNG. The regasification process consists in a bundle of two reservation prices: one referring to the service of the terminal, and one to the service of entry into the transmission network. Therefore, the auction premia need to be split across the two services (which is done in proportion to the underlying reservation prices). The information on auction premia for the regasification process is as follows: 0,00000099 EUR/kWh/d/d (gas year 2021-2022), 0,00003250 EUR/kWh/d/d (gas year 2022-2023). In regards the storage of LNG in the terminal, the premia of these capacity products for the year 2022 (the underlying information of the 4th quarter of 2022 is not yet final, as the definitive reporting is pending) Auction premia: 0,498 million EUR. Revenues from LNG storage capacity excluding auction premia): 10,44 million EUR. Overall the auction premia (regasification and storage of LNG) represented 3,8% of the overall revenues recovered at the LNG terminal in calendar year 2022 (including provisional information for the 4th quarter).

Table 4: Assessment of the procured volumes and costs related to storage injections done by selected Member States across summer 2022 – bcm – EUR/MWh.

Member State	Measures	Timing[138]	Filling difference – November 1st (pp)	Filling difference – April 1st (pp)	Measure contribution		Cost
					% of total GWV [139]	TWh	
Austria	Minimum volume in gas storage	Amended	4 pp	31 pp	4.5% (Jan 2023)	3.7 TWh	38 mil. €
	Strategic storage	New			24%	20 TWh	4 bil. €
	Unused booked capacities	Old			25% (to date)[140]	21 TWh	No info
Belgium	Tender of capacities	Amended	17 pp	2 pp	Impact cannot be estimated		No info
	Unused booked capacities	Old			Measure not used in practice yet		
	Discounts on storage tariffs	Amended			Impact cannot be estimated		12 mil. € (2022)
Bulgaria	Minimum volume in gas storage	Old	1 pp	54 pp	No info		No info
	Strategic storage	Old			No info		No info
Croatia	Minimum volume in gas storage	New	9 pp	53 pp	Impact cannot be estimated		No info
	Obligations imposed on designated entities / Appointment of dedicated entity[141]	New			6%	0.3 TWh	Loan of 400 mil. €
	Balancing stock managed by TSO	Old			1%	50 GWh	No info
Czech Republic	Obligations imposed on designated entities	Amended	-1 pp	23 pp	Impact cannot be estimated		No info
	Financial incentives for market participants (CfDs)	New			11%	4.6 TWh	No info
	Financial incentives for market participants (ČEZ State contract)	New			Significant impact according to ERU (info not available)		No info
	Unused booked capacities	New			10%[142]	4.2 TWh	No info
	Minimum volume in gas storage	Old			5%	No info	No info
	Strategic storage	Amended			6%	2.4 TWh	ca. 350 mil. €
Denmark	Obligations imposed on designated entities	Old	-3 pp	33 pp	16%	1.5 TWh	33.8 mil. €
	Strategic storage	Old			Measure not used in practice yet		

138 Old: Measure in place prior to the Gas Storage Regulation (not amended), Amended: Existing measure amended due to the Gas Storage Regulation, New: New measure due to the Gas Storage Regulation.

139 In 2022 unless otherwise stated.

140 Overlaps to an extent with the use of strategic storage, as part of the released capacity was used by ASGM to maintain its strategic reserves.

141 The measure has been classified by the NRA, HERA, under both measures of the Gas Storage Regulation.

142 Overlaps with the contribution of other measures, as part of the released capacity was booked by storage users implementing other measures.

Member State	Measures	Timing[138]	Filling difference – November 1st (pp)	Filling difference – April 1st (pp)	Measure contribution		Cost
					% of total GWV [139]	TWh	
France	Tender of capacities	Amended	20 pp	8 pp	Impact cannot be estimated		450 mil. € (2023)
	Appointment of dedicated entity	New			Measure not used in practice yet		
Germany	Obligations imposed on designated entities	New	6 pp	24 pp	34%	84 TWh	852 mil. €
	Unused booked capacities	New			Measure not used in 2022 and 2023		
	Strategic storage	New			7%	16.8 TWh[143]	420 mil. €
	Appointment of dedicated entity	New			20%	50 TWh	8.7 bil. €
Hungary	Minimum volume in gas storage	Amended	2 pp	5 pp	30%	19.8 TWh	No info
	Strategic storage	Old			30%	19.8 TWh	2 bil. €
Italy	Tender of capacities	New	-3 pp	14 pp	Impact cannot be estimated		No info
	Balancing stock managed by TSO	New			4%	7.4 TWh	837 mil. €
	Obligations imposed on designated entities / Appointment of dedicated entity[144]	New			16%	13.7 TWh	7.3 bil. €
	Financial incentives for market participants (premium)	New			60%	No info	No info
	Financial incentives for market participants (CfDs)	New			1%	No info	No info
	Strategic storage	Old			25%	49.3 TWh	N/A[145]
Latvia	Strategic storage	Amended	-14 pp	11 pp	9%	2.2 TWh	No info
Netherlands	Financial incentives for market participants	New	-1 pp	28 pp	9%	12.7 TWh	Zero
	Appointment of dedicated entity	New				12.2 TWh	No info
Poland	Obligations imposed on designated entities	Old	1 pp	15 pp	42% (2021/22)	15.2 TWh	No info
Portugal	Minimum volume in gas storage	Amended[146]	17 pp	29 pp	85%	3.05 TWh	No info
	Tender of capacities	Amended			Measure has no impact on its own		
Romania	Minimum volume in gas storage	New	14 pp	18 pp	88%	29.9 TWh	No info
Slovakia	Minimum volume in gas storage	Old	5 pp	20 pp	No info		No info

143 These volumes are part of the 84 TWh of the contracted SSBO products.

144 The measure has been classified by the NRA, ARERA, under both measures of the Gas Storage Regulation.

145 The strategic storage volumes were establishing several years ago, and those costs are not available.

146 Measure was amended in 2022 but not as a result of the Gas Storage Regulation.

<table>
<tr><th rowspan="2">Member State</th><th rowspan="2">Measures</th><th rowspan="2">Timing[138]</th><th rowspan="2">Filling difference – November 1st (pp)</th><th rowspan="2">Filling difference – April 1st (pp)</th><th colspan="2">Measure contribution</th><th rowspan="2">Cost</th></tr>
<tr><th>% of total GWV [139]</th><th>TWh</th></tr>
<tr><td rowspan="6">Spain</td><td>Minimum volume in gas storage</td><td>Amended</td><td rowspan="6">9 pp</td><td rowspan="6">21 pp</td><td>81%</td><td>28.3 TWh</td><td>No info</td></tr>
<tr><td>Tender of capacities</td><td>Amended</td><td colspan="2">No info</td><td>No info</td></tr>
<tr><td>Unused booked capacities</td><td>New</td><td colspan="3">Measure not applied yet</td></tr>
<tr><td>Strategic storage</td><td>Amended</td><td>59%</td><td>20.6 TWh[147]</td><td>No info</td></tr>
<tr><td>Appointment of dedicated entity</td><td>New</td><td colspan="3">Measure not used in practice yet</td></tr>
<tr><td>Discounts on storage tariffs</td><td>New</td><td colspan="2">No impact on its own</td><td>21.6 mil. €</td></tr>
<tr><td>Sweden</td><td>Appointment of dedicated entity</td><td>New</td><td>49 pp</td><td>54 pp</td><td colspan="3">Measure not applied yet</td></tr>
</table>

Source: ACER study on the impact of the measures included in the EU and national gas storage regulations.

147 These amounts are part of the overall stockholding obligations of the entities.