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Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020

Gas Wholesale Markets Volume

July 2021

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Glossary

Acronym	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
AGTM	ACER Gas Target Model
BAL (NC)	balancing (network code)
BBL	Balgzand Bacton Line
CAM (NC)	capacity allocation mechanism (network code)
CBA	cost-benefit analysis
CCGT	combined cycle gas turbine
CCS	Carbon Capture Storage
CEER	Council of European Energy Regulators
CEN	European Committee for Standardisation
CEP	Climate Energy Package
CHP	combined heat and power
(bio)-CNG	(low carbon gas origin)-compressed natural gas
CP	Contracting part (of Energy Community)
DA	day-ahead
DSO	distribution system operator
EBA	European Biogas Association
EC	European Commission
EEA	European Environment Agency
EFET	European Federation of Energy Traders
EnC	Energy Community
ENTSOG	European Network of Transmission System Operators for Gas
ESI	energy system integration
ESP	electronic sales platform
EU	European Union
EUA	European Union allowance
ETS	emissions trading system
EV	electric vehicle
FCFS	first come first served
FiT	feed-in tariff
Fit for 55	Gas Decarbonisation Legislative Package
GIE	Gas Infrastructure Europe
GLE	Gas LNG Europe
GPL	GASPOOL
GY	gas year
HGV	heavy goods vehicles
ICIS	Independent Commodity Intelligence Service
IEA	International Energy Agency
IEM	Internal Electricity Market
IGB	Gas Interconnector Greece-Bulgaria
IGM	Internal Gas Market
INT (NC)	Interoperability and Data Exchange (Network Code)
IP	interconnection point
IPCC	Intergovernmental Panel on Climate Change
LDV	light-duty vehicles
LNG	liquefied natural gas
LSO	LNG System Operator
LTC	long-term contract
MA	month-ahead
MGP	Hungarian virtual trading point
MMR	Market Monitoring Report
MS	Member State (of the European Union)
NBP	national balancing point
NECP	National Energy Climate Plan
NCG	NetConnect Germany
NGV	natural gas vehicle
NRA	national regulatory authority
OTC	over-the-counter

PVB	virtual balancing point
RAB	Regulated Asset Base
RED	Renewable Energy Directive
RES	renewable energy sources
RES-E	electricity from RES
RPM	reference price methodologies
SoS	security of supply
SRMC	short-run marginal cost
TAP	Trans Adriatic Pipeline
TAR (NC)	tariff (network code)
TEN-E	Trans-European Networks for Energy
TRF	Trading Region France
TSO	transmission system operator
TTF	title transfer facility
UGS	underground gas storage
UIOLI	use it or lose it
VIP	virtual interconnection point
VTP	virtual trading point
WD	Within-day
YoY	Year on Year
ZTP	Zeebrugge Trading Point

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Executive Summary and Recommendations

1 The Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) are together publishing the tenth edition of the annual Gas Wholesale Market Monitoring Report (MMR), produced in close cooperation with the Energy Community (EnC) Secretariat. This Volume of the MMR presents the results of monitoring the status of the European gas markets in 2020 and the progress made towards a fully functioning internal gas market in the light of the existing EU Regulation. This year, the Volume puts further emphasis on tracking the progress towards decarbonising the European gas markets.

2 Below, the main findings of the monitoring exercise are summarised for each topic, followed by recommendations on how to overcome identified barriers and to further improve the functioning of the internal gas market.

Relevance of market monitoring in the context of evolving market dynamics and the energy transition

3 **In the context of the requirement to decarbonise the internal energy market, a thorough market monitoring exercise has gained relevance.** The exhaustive assessment of the functioning of the EU energy markets enables policy makers to better understand the impact of regulatory policies in order to adjust market design. Recognising the importance of the decarbonisation ambitions, this edition of the MMR brings together a selection of quantitative and qualitative analyses that portray the current state of decarbonisation of the internal gas market and highlight the factors that will likely be pivotal for its evolution in the mid-term.

4 **The key findings of this MMR 2020 are summarised below, followed by recommendations per topic.** The MMR findings confirm that the functioning of the internal gas market has continued to improve and progress, despite the unprecedented events that affected the gas market during the year. Market price integration is high in areas covering three-quarters of EU gas consumption and importantly is advancing across several other jurisdictions.

A) The state of the Internal Gas Market and progress towards the European Gas Target Model[1]

5 **EU energy markets were significantly impacted by the COVID-19 pandemic in 2020.** The associated reduction in economic activity resulted in a substantial reduction of gas demand in Q2, which, among other factors, drove gas hub prices to an all-time low. Despite the impact of the pandemic, demand for gas in the EU was relatively robust in comparison to other fuels. On an annual basis, EU gas demand was reduced by 3.1%, while coal consumption decreased by 20%. From autumn 2020 onwards gas hub prices recovered and had surpassed 2019 prices by the end of 2020.

6 **Supply and demand in the EU and the UK gas markets went through a series of rebalances during the course of 2020.** These rebalances impacted prices, hubs' liquidity, cross-border flows and other key metrics, some of which moved in certain months to levels not seen before.

a) **LNG deliveries reached record highs in the first half of 2020 (+10% YoY) contributing to low gas hub prices. However, LNG deliveries decreased substantially afterwards, which coincided with a period of rising gas hub prices**[2]**.** From Q3 onwards and also across Q1 2021, higher demand and prices in Asian markets attracted LNG cargoes that would have otherwise been shipped to European regasification terminals. This confirms that EU LNG imports have become increasingly sensitive to the global LNG market, in which the EU plays the role of market of last resort[3].

1 The ACER European Gas Target Model is a conceptual guide for implementing the internal gas market endorsed by ACER, NRAs and gas sector stakeholders. At its core are ideas of competition at, liquidity of, and price integration between gas hubs.

2 LNG deliveries decreased by 20% YoY in the second half of 2020 and by 5% compared with 2019. See expanded considerations in Section 2.2.3.

3 See the reasons for the EU having assumed that role in footnote 55.

b) **Pipeline deliveries into the EU were impacted by the developments in the LNG market outlined above.** EU pipeline imports reduced in Q1 and Q2 due to the ample supply of LNG and the gas demand reduction caused by COVID-19. However, they recovered from June onwards. Russian-piped gas remained the largest source of EU gas supply (accounting for 32% of supply share). Russian gas flow patterns changed in 2020 as more gas was transported to the EU via the Nord Stream and Turk Stream corridors, to the detriment of transits across Ukraine[4].

c) **Together with record LNG availability, the reduction in gas demand caused by COVID-19 pushed EU gas hub prices to historical lows in the spring and summer,** prompting gas producers to seek an equilibrium between maintaining market share and safeguarding returns. Reduced prices of other energy commodities and high underground gas storage stocks at the beginning of the storage injection season in April contributed to the markets' low-price sentiment.

d) **EU storage sites began the 2020 injection season with record high stocks.** This high level of stock was driven by high LNG supply in the preceding quarters and lower energy demand caused by COVID-19. **However, withdrawal from EU gas storage sites increased by the end of Q3. This was due to increased gas prices, a reduction in LNG arrivals, and the start of colder weather.** In April 2021, **Underground gas storage stocks** were about thirty percentage points lower than in the preceding year.

e) **The volume of natural gas traded at hubs was at an all-time high in 2020,** with 14% more volume changing hands compared with 2019. Market participants continuously re-adjusted their positions due to a changing supply balance and high price volatility.

f) **The EU and the UK became more dependent on gas imports** as domestic gas production continued to decline (-20% YoY, covering for just 18% of EU gas supplies compared with 30% in 2014).

g) **A stronger price alignment between EU gas hubs was observed across the year.** Despite high price volatility, hub price convergence increased compared to 2019 as abundant supply smoothed out regional price differences.

h) **In 2020, new gas transportation infrastructure became operational,** for instance new large supply corridors such as Turk Stream and the Southern Gas Corridor or new LNG terminals such as the Croatian Krk terminal. It is anticipated that this infrastructure will significantly enhance competition at the regional level. Such competition should place downward pressure on prices which should in turn (ceteris paribus) result in lower prices paid by end consumers.

7 **The interconnected EU gas transportation systems and gas trading hubs were resilient** and accommodated flows and trade in response to short-term signals. The resilience demonstrated during the pandemic shows that the internal gas market continued to facilitate competition and liquidity to the benefit of EU gas consumers.

a) **Gas supply sourcing costs continued to converge in 2020 throughout the Member States (MSs).** Among other reasons, this was due to long-term supply contracts referenced to hub-prices increasingly becoming the norm throughout the EU. Various long-term supply contracts which were re-negotiated in 2020 now include hub price references – e.g. in Bulgaria[5]. Hub price-indexations tend to bring tangible benefits to consumers through lower prices.

b) **Competition and liquidity improved in some MSs' gas markets in 2020.** For example, upstream supply concentration in the South East European gas markets decreased following the start of gas exports from Azerbaijan.

4 See further considerations in Section 2.2.1 as well as a review of flow values in Figure iv in Annex 1.

5 See extended considerations on footnote 48.

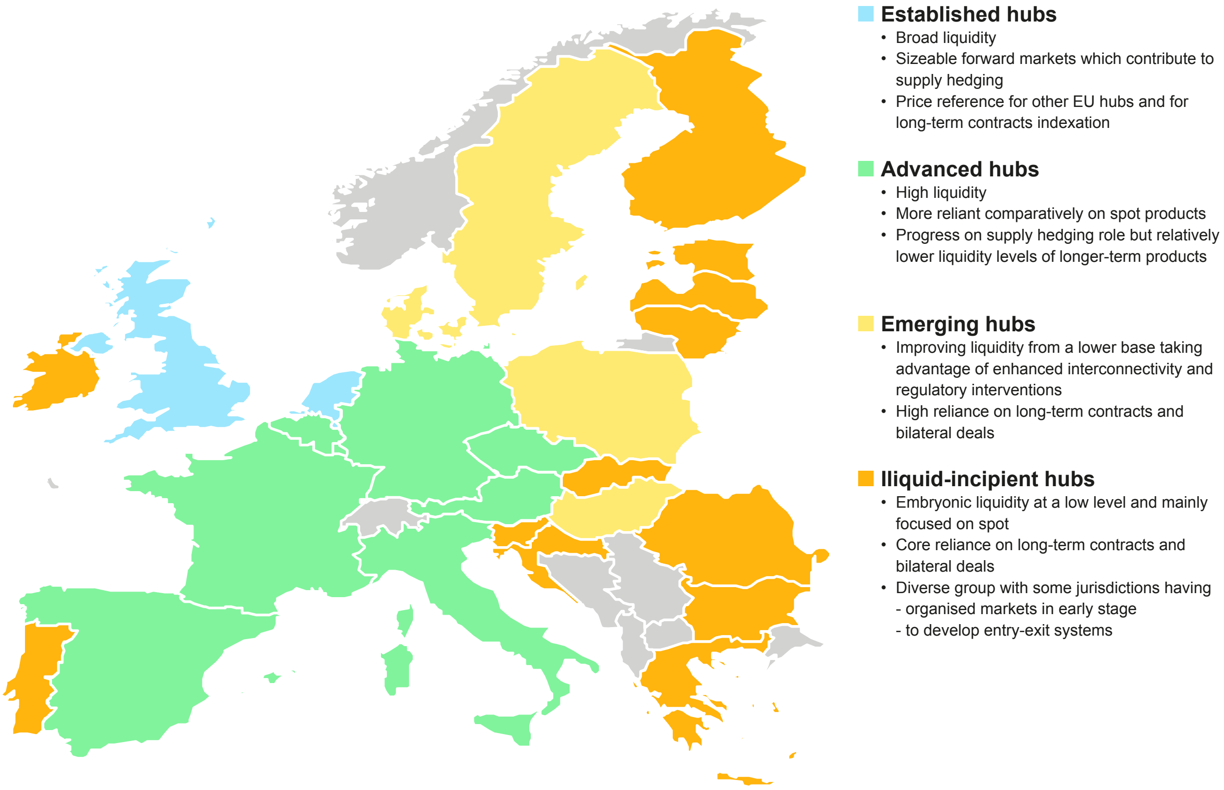
c) **Some of the internal gas market's less developed hubs showed promising signs of progress**
- Liquidity in the Baltic region was enhanced by the inclusion of products delivered at the Finnish hub to the regional Baltic exchange as well as the merger of the Estonian and Latvian hubs.
- The recently launched Balkan gas exchange, which offers products for delivery at the Bulgarian virtual trading point grew its volumes throughout the year.
- The Iberian exchange Mibgas started offering products for delivery at the Portuguese virtual trading point in the first quarter of 2021.
- The trading platform in Greece is scheduled to become operational before the end of 2021.

8 **However, the potential for further integration of EU gas markets still remains, as some differences in EU gas markets' competitiveness persist.** These differences tend to result in a price disadvantage for consumers in less developed markets. As such, opportunities for further improvements exist and policy makers, regulators and TSOs alike should aim to improve competiveness to deliver further value for gas consumers.

a) **Market price variations across the EU tend to arise from differences in the role that both national and transnational gas hubs play for hedging supplies and** from divergences in gas markets interconnectivity, as well as diversity of supply. Sourcing gas at the price levels of the most liquid North West European hubs would yield approximately 3 billion euros of savings to the gas consumers in the more expensive Central and South South-East Member States (or approximately an average 25 euros per annum for individual household consumers).

b) **The Dutch hub, TTF, has inherently attained the leading role to hedge continental forward volumes, followed by a number of other North West and Mediterranean gas trading hubs.** A number of other hubs have advanced in recent years, but their market liquidity tends to be limited to spot transactions.

Figure i: Ranking of EU and UK hubs based on monitoring results



Source: ACER based on AGTM metric results.

9 **Building on this hub-functionality status and on the enhanced accessibility achieved between markets in recent years, a model of EU internal gas market is operative today.** This outcome is clearer in the North West region and in selected parts of Central Europe, but is also progressing across various other jurisdictions.

Recommendations to back the Internal Gas Market and the ACER Gas Target Model

10 Gas markets remain a crucial part of the EU's internal energy market. Natural gas represents 21.5% the EU's primary energy consumption and is the dominant source (32.1%) of energy consumed in EU households today[6]. The sector is expected to remain important in the decades to come by enabling a higher penetration of renewable electricity generation in national power portfolios and by assisting in the delivery of the decarbonisation targets. The latter objective will be achieved by shifting from conventional natural gas into low-carbon and renewable gas but also by its switch from coal-fired power generation. Therefore, a more complete implementation of the internal gas market following the principles outlined in the ACER Gas Target Model can still render substantial benefits to EU consumers in the years to come.

11 On the one hand, a more complete realisation of the internal gas market requires improving the market functioning of national hubs. On the other hand, it entails enhancing cross-zonal market access to further facilitate supply competition and price convergence.

12 Market accessibility has been clearly facilitated by the proper implementation of gas network codes. Therefore, the relevant national decision makers are called on to keep fully implementing them. This requires an ambitious regional coordination and the genuine promotion of transparent hub trading in all areas. It is interesting to note that while few market mergers have already formally occurred, these are not indispensable to back the ACER Gas Target Model vision, as long as a proper accessibility between hubs and reasonable cross-border tariff levels enable sufficient market integration.

13 To further promote hub trading, targeted regulation should be applied in MSs with less competitive and more illiquid gas markets. Such regulation might include gas release programmes in order to reduce the market power of incumbents. Other instruments, like appointing hub market makers or adapting specific provisions via a regulatory toolkit may also be warranted. Furthermore, MSs should avoid taking measures that go against the internal gas market. They should, for example, remove any remaining barriers to market entry, such as limitations to free cross-border trade of locally produced gas or unjustified storage obligations for market participants. In addition, transparency needs to be granted, so all market participants have access to the same level of information.

14 These considerations are all valid – and even more essential – for the Energy Community Contracting Parties (EnC CPs). Those countries still show a sub-optimal level of market development and higher supply-side concentration than MSs. Therefore, continuous alignment of the EnC CPs to the *acquis communautaire* of the EU is a pre-condition for enhancing market integration and cross-border trade with the EU and among themselves.

B) Decarbonisation and the internal gas market

15 **This edition of the MMR brings together a selection of quantitative and qualitative analyses that portray the current state of decarbonisation of the internal gas market** and highlight the factors that will likely be key for its evolution in the mid-term:

a) **The supply share of low carbon gas is still low at the EU level.** Low-carbon gases accounted for 3.8% of EU and UK gas consumption in 2020. However, volumes have doubled in the last 10 years. Of the biogas produced, 13% is upgraded into biomethane and injected into the network. Globally, the EU is the leading producer of biogas. The prevalent feedstock for biogas production in the EU is agricultural.

6 Around 40% of European households are connected to the gas network. On average, they spend 700 euros on gas, 2.5% of their average income, although this conceals considerable differences among Member States. Together with this Volume, ACER has recently published a Fact Sheet summarising the main aspects related to the significance of the EU gas sector.

b) **Hydrogen production in the EU is small relative to future expectations.** An estimated 340 TWh of hydrogen are produced per year, which represents less than 2% of the EU's total energy consumption. Most hydrogen originates from oil refinery by-products, followed by steam methane reforming without carbon capture. In 2020, electrolysers produced less than 3% of commercial hydrogen volumes. Statistical offices still assess the use of renewable electricity as input to operate the electrolysing plants as very minor.

c) **The cost of the currently cheapest low-carbon gas, biogas, was four times higher than the price of unabated natural gas,** when taking the average gas hub spot price in 2020 as the benchmark[7]. The price of green hydrogen was at least three times the average price of electricity[8].

d) **Ad-hoc financial support has been crucial to incentivise the expansion of production of low-carbon gases to date.** Support measures, which take different forms in different MSs, have so far been chiefly used to promote the production of biogas and biomethane, but the support framework is expanding to also incentivise the production of hydrogen.

e) **The current gas network as well as most end-use appliances can accommodate biomethane without significant upgrades.** However, the readiness of the gas network to integrate hydrogen admixtures is still being investigated[9].

f) **According to some studies[10], methane leakages represent on average 2–3% of the final supplied gas.** Reduction of methane leakages is crucial, as methane is a more potent contributor to the greenhouse effect than carbon dioxide in the short-term. Corrective actions are being developed, but further action is needed both in the EU and in countries where gas consumed in the EU is produced and transported.

16 **In the mid and long run, scenarios for the production and consumption of low-carbon gases are proposed.** Although these scenarios use different assumptions in terms of costs and investment evolution, which lead to some rather diverse results, the overall targets included in EC Strategies and MSs' national energy and climate plans are[11]:

a) **Biogas and biomethane production could double by the end of this decade** and account for 20% to 30% of gaseous fuel demand by 2050.

b) **Hydrogen, in its diverse forms, could account for 10% or more of the EU's gaseous energy consumption in 2030 and have a comparable supply share to carbon abated natural gas in 2050.** Although the comparison is not straightforward, this implies that hydrogen would scale up much faster than renewable electricity has done in the last decades.

c) To achieve those targets, **the price gap between low-carbon gases and conventional natural gas needs to be closed** in the coming years:
- The subsidies for production and consumption of conventional natural gas are expected to decrease in the coming years and could be fully phased out across the decade[12], whereas the amount of carbon emission allowances under the EU Emission Trading System will keep decreasing, likely resulting in higher carbon prices[13]. These factors will lead to an increase in the costs associated with the consumption of unabated natural gas.

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7 Record low gas prices were observed in mid-2020 but have recuperated since then.

8 The comparison considers the calorific value of hydrogen (MJ/kg) and its production cost per kg at an electrolyser plant and the average price of electricity at the German spot market in 2020 in euros/MWhel. See further considerations at Section 3.5.

9 ACER performed in July 2020 a survey among NRAs, aimed at identifying the technical ability of the EU gas transportation system to accept carbon neutral gasses. The results of the survey show that only eight MSs accept at present injection of hydrogen in their gas networks. 5.4 further discusses the topic.

10 See Section 3.7.

11 Ambitious plans and investment commitments to promote the shift from conventional natural gas into hydrogen and low-carbon gases in the internal gas market were settled in 2020. At the EU level, these plans are presented in the EC's Energy System Integration, Hydrogen and Methane strategies, which were published in 2020. In some MS, gas decarbonisation plans have also been expressed in National Energy and Climate Plans.

12 See for example EU Energy Commissioner Kadri Simson's considerations on the subject.

13 The EU allowance (EUAs) average price was of 25 euros per tonne in 2020, but a level of 40 euros per tonne has been maintained since early 2021. An increment of 10 euros per tonne in emission prices outcomes a rise in the emission costs of average gas-fired power plants of 4 euros per MWhel.

- Technological developments, economies of scale and a favourable evolution of renewable electricity generation costs could considerably enhance the future price competiveness of carbon neutral gases.

d) **Hydrogen, in particular green hydrogen (i.e. hydrogen produced using renewable electricity at water electrolysers), has become the central focus of plans to decarbonise the internal gas market.** Blue hydrogen (i.e. hydrogen produced from natural gas with CO_2 capture and storage) is expected to have a transitional short-to-mid-term role, helping to scale up production without the associated emissions of grey hydrogen (i.e. hydrogen produced from natural gas without CO_2 capture and storage).
- The EC is targeting 40 GW of electrolysers in the EU by 2030, plus another 40 GW in Europe's neighbourhood for export to the EU. Together, they could meet some 6% of the current level of EU gas consumption. Further targets for electrolysers are being developed, with the EC strategy ambitioning various hundreds of GW installed by 2050. These developments will require massive investments over the next thirty years. Such investment will not be limited to green hydrogen production but will also go into network adaptation and importantly into additional electricity generation from renewable sources.
- The operation of the electrolysers targeted for 2030 with renewable power supply would require an extra 7% of EU electricity output by that year. The EC Hydrogen strategy suggests that in 2050 up to a quarter of all the EU renewable power generation could be devoted to produce green hydrogen at water electrolysis plants.
- This vision puts green hydrogen and renewable electricity at the core of building an EU climate-neutral energy-integrated system. However, the actual penetration of green hydrogen will be determined by the interplay of policy action and market drivers; if green hydrogen manages to position itself among the most favourable technologies this would lead to a meaningful increase in its production, and likely, to a higher presence than that of other decarbonised energy options in the mid-term.
- Policy action will clearly have a decisive influence in areas such as infrastructure development, the granting of incentives or the funding of research and development activities. Therefore, the overarching aim shall be facilitating as much as possible a technology-neutral playing field.
- The Emissions Trading System will be instrumental from the market side. On the one hand, a higher pricing of carbon – led by a narrowing in the emission allowances allocated by Member States as well as by the inclusion of new economic sectors into the scheme – is called to increase the presence of renewable production in EU power systems. That will make the direct supply of electrolysers from the power grid more carbon-neutral, as well as more secure, competitive and at higher load factors[14]. That setting, completed by the option to acquire certificates that prove the renewable origin of the electricity that sources the electrolysis plants, will counterbalance the need to devote dedicated renewable supply (more intermittent by nature) to the electrolysing plants. On the other hand, rising carbon prices in the EU Emissions Trading System will discourage the consumption of unabated gas, including its use for producing hydrogen with steam methane reforming. Together with the technology improvements called to reduce the electrolysers' costs, this would make the production of green hydrogen more and more economically attractive.
- Furthermore, additional elements could incentivise the production of green hydrogen, such as certifying its production with a wide-reaching and well-functioning system of Guarantees of Origin. That would promote the switching into green hydrogen of selected large industrial consumers that rely today on more carbon-intensive fuels and who need to offset their emissions. However, this consideration is not solely applicable to green hydrogen, but also to other low-carbon technologies. Market participants will eventually decide the energy supply portfolios that serve their decarbonisation needs best.

e) **Gas could also play a role in decarbonising the transport sector.** The contribution of gas is anticipated to be higher in heavy goods vehicles than in light duty vehicles, as most estimates and plans predict that electric vehicles will play the dominant role in the latter category[15].

14 It will be effective to create room for locational signals to determine where electrolysers are more suitable.

15 Some estimates ambition a 30% natural gas share in buses and trucks by 2030, as well as 10% of EU's light duty vehicles. Section 3.4 further discusses the assumptions.

17 To enable such a shift in the mid-term, various European and national funds are mobilised[16], helping to create a large scale industrial-government co-financing framework for new investments in low-carbon technologies. In addition, the regulation that will govern the gas decarbonisation shift must further clarify a number of interrelated aspects.

Recommendations to back Gas Sector Decarbonisation

18 As discussed in Section 3.8, the regulatory aspects governing the gas decarbonisation shift can be generally grouped into the six areas shown in Figure ii:

Figure ii: Main regulatory areas governing gas sector decarbonisation

Technical rules	Market rules	Access conditions	Participation	New investments	Support
Setting the technical rules that will define gas quality, blending and interoperability aspects.	Setting up market rules that promote and facilitate the access to liquid markets.	Determining the network access conditions for new gases; connection tariffs will be key elements for that.	Determining the activities and the conditions at which the market participants will be allowed to invest.	Defining a framework to identify new network investments and to value the existing regulated asset base in case of transfer of assets.	Identifying and mobilizing ad-hoc support to the new technologies, at least in early phases.

Source: ACER.

19 Discussions about the best suitability of the regulatory framework are taking place in view of the upcoming Fit for 55 legislative package, likely to be tabled by the end of 2021. The legislative package is expected to clarify various relevant regulatory provisions that will enable an increase in the production and consumption of low-carbon gases. In addition, the Fit for 55 Package may outline a roadmap for the decarbonisation of the internal gas market. The final actual provisions will influence the stakeholders' business models.

20 The future regulation governing the gas sector decarbonisation shift must be built on the foundations of the current regulatory model. The current regulatory model has proved successful in promoting well-functioning, integrated and competitive gas markets for EU gas consumers. This will create regulatory certainty and thus support market-based investments while protecting existing consumers. It is essential that the clean energy transition does not lead to national market fragmentations, which may then need many years to re-align and result in different outcomes for EU gas consumers.

21 ACER and CEER have jointly made a number of recommendations shared via related white papers. This MMR takes account of the white papers recommendations, expanding the proposals expressed in previous editions of the MMR:

- The main principles that govern the internal gas market today are to be maintained for low-carbon gases: i.e. unbundling, third-party access, non-discrimination, absence of cross-subsidies or monitoring and oversight[17].
- A clear separation between regulated network activities and market-based production and supply activities shall be maintained.
- Power-to-gas production facilities are in principle a competitive activity. Competitive mechanisms, such as auctions should rather be used to assign the plant operators.

16 At least 30% of the EU's 2021–2027 budget, as well as the funds of new Recovery Plan for the EU, have been earmarked to support future climate action. Together they form the largest stimulus package ever financed through the EU budget, of 1.8 trillion euros.

17 Private business-to-business networks can be exempted from regulation, like closed distribution systems in a first phase.

- The role of Transmission System Operators (TSOs) and Distribution System Operators (DSOs) is to be limited to foster research in early phases – on top of reliable network operation –, rather than owning or operating production plants. However, if no sufficient market interest is detected, larger roles could be assigned to TSOs under controlled conditions[18].
- Other instruments than tariffs should be used to incentivise low-carbon gases uptake.
- As a rule, separated hydrogen and methane Regulated Asset Bases are favoured, while potential transfers of assets should be based on the regulated value at the time of transfer, as a default rule.
- A potential pan-EU level abolishment of intra-EU IP tariffs to promote decarbonisation is judged as not necessary and too complex at this stage.
- Well-functioning Guarantees of Origin need to be set as they will be instrumental to promote trade.
- The trading of low-carbon gas at organised markets needs to be promoted, seeking for synergies with the current conventional gas trading platforms. Low-carbon gas injected at distribution level should be able to be equally traded at the national virtual trading points

22 Finally, a flexible and gradual approach to regulating the sector is recommended. This is to better accommodate effective regulation during the early years of the market and grid development, acknowledging the uncertainties that will need to be faced. In doing that, consistent monitoring to adapt regulation based on market developments will be key.

C) Network Codes and relevant regulation governing gas markets access

23 **The five gas network codes (NCs) gradually adopted since 2013[19] are enhancing EU gas markets integration.**

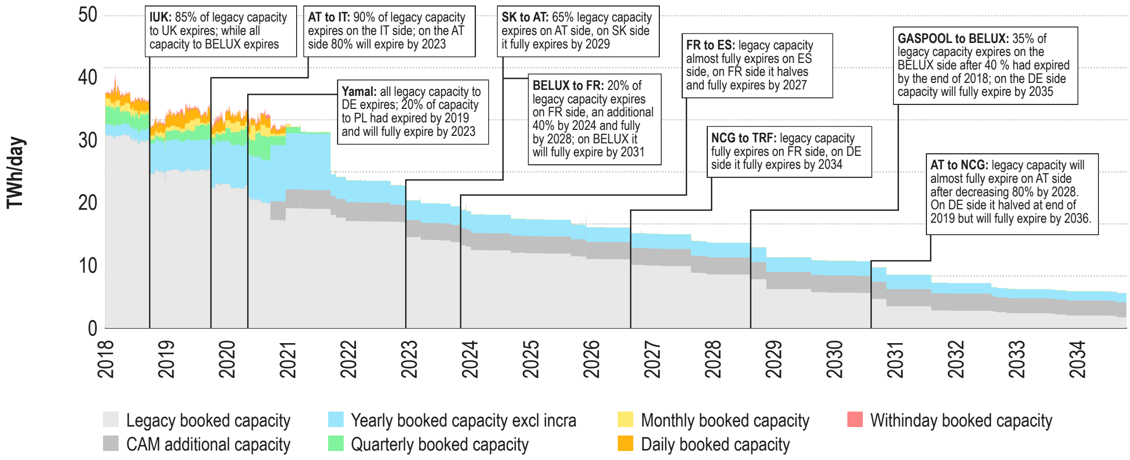
a) **The Capacity Allocation Mechanism Network Code (CAM NC) is facilitating more efficient and flexible booking of gas transportation cross-border interconnection capacity.** While half of the long-term capacity contracts active in 2016 had expired by the end of 2020[20], CAM auctioned products have overall replaced them at a relatively high rate so far, despite some differences per border. Quarterly and chiefly year-ahead capacity products have attracted most of the new CAM bookings. However, as Figure iii shows, various relevant interconnectors will see their legacy long-term contracts expire in the next couple of years, whereas all pre-CAM prevailing contracts will have almost completely expired by 2035. Therefore, more cross-zonal capacity will become available to the market. The expectation is that the average bookings at EU gas interconnectors will gradually decrease, driven by the rising supply role of LNG, the foreseen stagnation of demand and the increased injection of low-carbon gases, which are expected to be mostly produced domestically.

18 Similar approaches have been considered for electric vehicles recharging points and electricity storage. A hybrid possibility is that network operators become responsible for building and operating the facilities to serve the commercial petitions of those market participants having gained access capacity. If market interest is detected later they may have to divest.

19 The Third Gas Package set the legal basis to establish more detailed common rules to govern the cross-border accessing of EU gas markets – the gas Network Codes and Framework Guidelines – with the aim to further advance their interconnection as well as to promote the AGTM hub-cemented vision. See Chapter 5 for a more extensive enumeration of the codes' implementation dates and their market effects.

20 By the end of 2020, some legacy long-term capacity contracts had expired in all of the EU transmission systems.

Figure iii: Evolution of booked capacity and expiration of legacy capacity contracts at CAM relevant points – 2018–2035



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA.
Note: See Figure 31 considerations that also apply here.

b) **Assisted by the higher flexibility in transportation capacity booking, cross-border gas flows are progressively becoming more responsive to hub price signals.** The situation can however differ between interconnectors, as their price responsiveness is dependent on their specific market role and their prevailing transportation contracts. Utilisation patterns of interconnectors tend to reveal the type of supply function that they perform; this role can range from facilitating core, baseload supply to facilitating supply competition and assisting price arbitrage.

c) **Market participants are also increasingly using LNG and underground gas storage as short-term flexibility tools,** allowing for the optimisation of portfolios and short-term price hedging. Nonetheless, longer-term contracts are still dominant in the supply and capacity portfolios of gas shippers with a larger reliance on liquefied gas. The profile of bookings and use of each LNG terminal is shaped, among other factors, by the regulatory aspects that govern their access. Their suitability attracts increasing discussion, as cross-terminal competition is intensifying across the EU.

d) **The Tariff NC was implemented from the end of 2019 onwards. This implementation has improved the gas network's tariff transparency and cost-reflectivity. The new tariff methodologies set in accordance with the code have brought some relevant changes in the tariff levels of selected gas systems.** Assessing the impact that those changes have had on hub price levels is not straightforward, since the interconnector utilisation and the capacity booking strategies of shippers is complex[21]. So far, the rises in tariffs occurring at selected interconnectors have not worsened hub price convergence. However, extraordinary non-regulatory factors like the extra deliveries of LNG and COVID-19 related demand destruction modified the normal setting across 2020 and led to reinforced hub price convergence in comparison to 2019.

e) **Analysis of gas balancing markets reveals how an ambitious implementation of the BAL NC reduces the active role of TSOs in gas network balancing** and also benefits spot markets' liquidity. There are differences between MSs in terms of the role of the TSO and of the products they use for balancing purposes. The majority of TSOs within the systems assessed were able to procure all necessary balancing volumes using the within-day title product offered on trading platforms, which is placed highest in the merit order according to the BAL NC.

f) **Finally, under the Interoperability NC subsection, the MMR outlines the technical challenges that need to be addressed to develop a more harmonised technical framework** enabling the injection of large quantities of biomethane and hydrogen. Any actions to address these challenges should neither create a barrier to cross-border trade nor negatively impact final consumers.

24 **Importantly, the gas network codes are and will continue to be relevant for specifying the market**

21 Section 5.2.1 revises the factors that add to this complexity as well as the assessed market effects.

principles and technical rules governing the gas decarbonisation shift in the coming years. Therefore, monitoring their market effects in view of possibly adapting some of their provisions to enable decarbonisation remains necessary.

25 **Regulations governing the use of infrastructure not covered at present by network codes, e.g. LNG or underground storage sites, will also need to be evaluated.** This is due to the fact that such infrastructure will have a significant role to play in the energy sector decarbonisation. For example, underground storage is becoming more strategic for the construction of an integrated energy system as low-carbon gas has the potential to be transported and stored at lower cost and in larger volumes than electricity. However, a significant increase in existing low-carbon gas penetration in the gas network will need to be delivered to unlock this potential opportunity.

Recommendations related to Network Codes and other relevant regulations governing gas market access

26 The internal gas market construction requires standardised and sufficiently stable rules that promote steady market access conditions. However, there is also a need to provide a certain flexibility, to adapt to evolving market circumstances. This flexibility is becoming more relevant as the network access provisions, such as the tariff rules or national system interoperability aspects governed by the current gas network codes need to fit the decarbonisation shift in the coming decades. Linked with this, the market operation will also evolve as low-carbon gases increase their penetration.

27 This MMR primarily endorses continuing the harmonised implementation of NCs, which have proved instrumental for natural gas market integration. In addition, NRAs are requested to periodically assess and consult with gas sector participants if the regulatory framework serves the development of the gas markets, and importantly low-carbon gas well. If the results of this monitoring exercise indicate a need for adjustments, NC provisions shall be adapted where appropriate, following the foreseen procedure.

28 For example, the implementation of the CAM NC has enabled shippers to profile their booking portfolios in a more efficient manner using hub price signals. NRAs and TSOs are therefore requested to continue the coordinated implementation of the CAM NC, also extending its implementation to the EnC Contracting Parties borders.

29 Further flexibility of the capacity products' timeframes and their allocation procedures has been requested by a number of market participants, especially gas traders. Also, past amendments to the CAM NC, such as increasing the frequency of the offer of quarterly products and the fixing of a closer to delivery timing for the auctions of the yearly capacity product have rendered positive outcomes. Therefore ACER and ENTSOG shall keep working on issuing proposals to explore the possibility of increasing the frequency of CAM auctions or increasing the variety of products. Any changes will strive to continue to maintain a competitive and recognisable setting that respects the network code principles. The proposals shall be explored with the stakeholders[22].

30 Similarly, some shippers and traders have requested a revision of the tariff multipliers of short-term capacity products. Their aim is to bring them to levels closer to long-term products to facilitate cross-border spot trading, which would reinforce hub price convergence.

31 At the end of 2020, in view of a TAR NC mandate[23], ACER ran a public consultation to evaluate the stakeholders' positions about the possibility of introducing a new lower cap for short-term tariff multipliers. The exercise led to an overall identification of lower multipliers as a relevant factor to enhance hub price convergence. However, ACER decided not to prescribe any new lower EU general cap. The reasons are detailed in Section 5.2.2, which argues that equally important to the multiplier levels are the absolute level of the reference tariffs. NRAs shall safeguard an efficient redistribution of network costs while guaranteeing a sufficient revenue recovery for TSOs.

22 For example, higher flexibility has been solicited by EFET via the FUNC Platform.

23 The TAR code advised that the multiplier cap for daily and within-day products shall be reduced to 1.5 in 2023 if ACER issued a recommendation in this direction, after having assessed the potential impacts that this limitation could ensue over shippers' booking behaviour, hub price convergence and revenue recovery.

32 At any rate, the effects of multipliers and of the changes to gas transportation tariffs on market functioning should be regularly monitored. This is to assess if and where they may be related to possible adverse effects on, for example, utilisation of IPs, market price integration or competition. Particular attention should be paid to the possibility to allow reductions of reserve prices for cross-border capacity combined with inter-TSO compensation and tariff reallocation measures, when pursuing markets' price integration.

33 With regard to tariffs, ACER also recommends that NRAs perform network utilisation scenarios covering at least the next immediate tariff period. Those scenarios could be coordinated at the EU level bringing in input from ENTSOG's scenarios. This is to assess the possible impacts of declining natural gas demand on network tariffs and take actions in response to such impacts. Those assessments would serve as input for possible adjustments on the parameters underlying the allowed revenues (e.g. depreciation profile).

34 In the area of balancing, as a rule, the BAL NC implementation shall be pursued as it also benefits spot trading activity. In some balancing zones, measures currently in place that limit either the TSO's need to trigger balancing actions or network users' possibility to change positions within the day should be removed. In parallel, it is recommended that TSOs, who know their customers better, follow their credit limits more closely, as well as share intelligence about balancing misconduct across the borders should establish a central registry of market participants as an additional tool to alert for such behaviours. The registry could be made accessible to participating TSOs, NRAs, the Agency and ENTSOG.

35 The operation of gas-fired power plants will also benefit from some further flexibility in areas such as short-term capacity allocation and the promotion of enhanced liquidity in within-day hub products. Section 5.3.1 discusses a number of concrete proposals.

36 A similarly adaptive approach is recommended for other policy areas not specifically governed by network codes. In the area of new gas infrastructure investment, the proposal to no longer considering new conventional natural gas projects as eligible for EU financing under the TEN-E programme is acknowledged. This is in view of the shift towards decarbonisation[24]. EU gas transportation networks have, in general, reached high levels of interconnectedness. This has enabled market integration, increased competition and contributed to ensuring security of supply for EU gas consumers. However, parts of the gas transportation infrastructure are far from being highly utilised. Given the ambitious energy decarbonisation targets, as well as some changes in gas flows that could impact the utilisation of certain cross-border pipelines, there is a risk that some regulated infrastructure will become stranded, potentially resulting in social welfare losses for consumers. Therefore NRAs and MSs should continue to apply a careful approach when approving new investments in traditional natural gas infrastructure[25].

37 In the case of LNG, the need for greater transparency regarding the access conditions of some terminals is recognised. Transparency of tariff levels and capacity availability is key for market participants, so NRAs and LNG system operators are recommended to expand the coverage of the information absent from the current EU-wide platform, which compares services[26]. Furthermore, while acknowledging that there is no consensus on the need for a harmonised LNG-specific EU regulatory framework – and recognising that the distinct features of LNG terminals and offered services would make this very intricate – there is a need to better understand whether the existing framework is hindering fairer competition between terminals[27]. In all cases, effective access to virtual trading points has to be guaranteed to LNG shippers. The offering of primary capacity allocation via auctioning of standard products as a general rule could be an initial non-mandatory reference, where this mechanism can be compatible with the terminals' services.

38 When examining underground storage sites, evidence suggests that seasonal security of supply tends to be sufficiently guaranteed in most MSs by a market-based approach to underground storage capacity. However, it is the prerogative of MSs to decide to hold strategic gas reserves based on their risk assessment and, understandably, security of supply concerns are a key responsibility for national authorities. On the other hand, storage obligations imposed on market participants can limit or prescribe the use of commercial storage, or even of cross-border capacity. And in selected cases they can be perceived as distortive to market functioning and a barrier to trade. Therefore, regulations that enable flexible and

24 The EC proposal is to solely finance low-carbon gas infrastructure as well as, chiefly, electrical interconnectors and the deployment of offshore renewables.

25 The fitness of these investments may vary per case. Selectively located infrastructure gaps would still clearly promote market integration in some areas, but, overall, prudence and clear market-driven support shall be the guiding lines.

26 GLE maintains a transparency platform that makes EU LNG terminals technical information more accessible to the market.

27 See, for example, the EC consultancy study on gas market upgrading and the modernisation of LNG terminals.

market-driven use of underground gas storage are to be prioritised.

39 Storage regulation is shaping the conditions under which underground gas storage facilities assist the transition towards a carbon-neutral economy. Some sites will increasingly be used to store methane to source blue hydrogen production. However, other sites may end up injecting carbon dioxide generated in carbon capture processes. Furthermore, faster cycle facilities, especially salt caverns, will enable better storage and injection of green hydrogen produced by intermittent renewable electricity. The suitability of the sites' accessing conditions needs to be evaluated to determine how they can better contribute to the energy sector decarbonisation ambitions.

1 Introduction

40 This MMR, which is in its tenth edition, consists of three volumes, respectively on the Electricity Wholesale Market, the Gas Wholesale Market, and the Electricity and Gas Retail Markets, the latter also looking at Customer Protection aspects. It covers the MSs and, for selected topics, also the Energy Community Contracting Parties.

41 The Gas Wholesale Volume presents the results of monitoring the European gas wholesale markets in 2020[28] and their trajectory towards an Internal Gas Market, in light of the existing EU Regulation. The Volume is divided in two parts and four analytical chapters.

- Chapter 2 starts by presenting the status of the IGM in 2020. It first summarises the main supply and demand, price, cross-border flows and infrastructure developments occurring throughout the year and compares their evolution year on year to glean out market tendencies. The chapter follows with an assessment of the utilisation of LNG and UGS infrastructure, discussing their market perspectives. The ambition is to provide a succinct overview of the performance of the IGM and of the factors that shape efficient gas markets integration.

- Chapter 3 brings together a selection of quantitative and qualitative analyses that help to portray the current state of the EU gas systems' decarbonisation as well as to look into its envisioned mid-term progression. Chapter 3 is new to this MMR edition, and is included to emphasise the importance of the transition towards low-carbon gases that the sector needs to embark upon in the years to come. The Chapter starts by analysing the recent coal to gas shifting trends in power generation, to offer a perspective of the role played so far by gas to decarbonise the EU energy system. It follows offering information about cost and presence of the low-carbon gases, in addition to discussing the prospects and key drivers for their further progression. Finally, some relevant regulatory considerations are outlined for those aspects more closely related to market integration.

- Chapter 4 assesses the performance of the individual national gas markets by means of calculating the so called ACER Gas Target Model metrics. Those metrics evaluate on the one hand the structural competitiveness of the national gas markets and on the other hand the transactional activity of their hubs[29]. The metrics were defined together with the industry[30] with a view towards tracking the accomplishment of the market vision that the AGTM proposes. This vision aims at setting a competitive IGM, comprised by entry-exit market areas served both by sufficiently liquid hubs and by appropriate levels of infrastructure. Access to sufficiently liquid hubs is thus a core element of the market model. Specifically, the model calls for sufficient tradability of hub forward products, to enable market participants to adequately hedge their supply portfolios in a more transparent and competitive manner (the AGTM invites to study market mergers for those market areas that do not reach hub liquidity thresholds). This is why the gas hub liquidity assessment conducted across Chapter 4 put the focus on measuring aspects such as the breakdown of gas traded volume per product duration and the hub's trading horizon. The Electricity Wholesale MMR similarly assesses the liquidity of EU power markets across different timeframes, putting an emphasis in turn on measuring metrics that are core to constructing the Internal Electricity Market (IEM). While both sets of metrics are somewhat different for electricity and gas, each set has been developed to better measure the most crucial aspects of the respective market design.

- Finally, Chapter 5 analyses the market effects brought about by the implementation of the Gas Network Codes and Commission Guidelines in recent years. The analysis is structured in four different subsections that look at each individual code – the capacity, tariffs, balancing and interoperability codes – even if the effects of their gradual implementation are clearly interrelated.

42 The recommendations based on the outcome of the analytical work performed are included in the Executive Summary.

28 Selected analyses are expanded up to summer 2021.

29 Results of market health metrics indicate whether a gas wholesale market is structurally competitive, resilient and exhibits a sufficient degree of diversity of supply; the results of market participants' needs metrics indicate the level of liquidity of a gas wholesale market. Indicators methodologies are available here.

30 See European Gas Target Model review. Footnote 1 in the Executive Summary adds further clarifications.

PART I: Gas Market trends in 2020

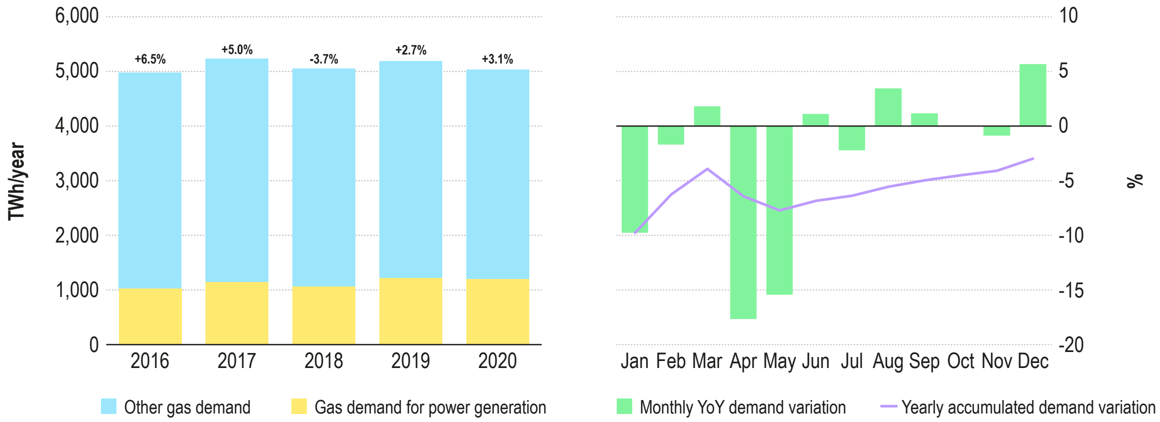
2 Overview of the Internal Gas Market in 2020

2.1 Market developments

2.1.1 Demand developments

43 Demand for gas in the EU and the UK fell by 3.1% in 2020, affected by the economic impact related to COVID-19. A warm start to the year and the fall in total electricity generation (-4.3% YoY) coupled with a rising share of renewable electricity (RES-E) contributed to depress final gas consumption. The gas demand drop was uneven across the year though, as Figure 1 illustrates.

Figure 1: EU and UK gross gas inland consumption and YoY monthly evolution – 2016–2020 and 2020 vs 2019 – TWh/year and %



Source: ACER calculation based on Eurostat.

Note: Demand data per MS is accessible in the MMR data portal CHEST. Demand varies greatly among countries: Germany, UK and Italy account together for more than half of EU plus UK gas consumption, while the twelve MSs with the lowest-demand amount to less than 10%.

- In spring, coinciding with the more severe lockdowns of the first pandemic wave, gas demand fell by up to 20% YoY at peak weeks. By the end of May 2020, it had fallen by 8% YoY on average.
- Consumption recovered in the third quarter of the year, backed by record-low prices and lesser nuclear and coal-fired power generation[31]. Gas demand held remarkably well by then compared to other fuels; i.e. it had fallen 4% YoY by October, while oil demand had dropped by 12% and coal by 25% in the same period.
- From October, the second wave lockdowns pressed gas demand down again, even if improved household consumption counterbalanced some industry closures. Demand rose in the last part of the year amid colder than usual weather.

44 Yearly demand variations showed some differences across MSs, reflecting heterogeneous local dynamics, dissimilar relevance of gas-fired plants for power generation and uneven COVID-19 impact across economic sectors[32].

31 Lower gas prices and sharp rises in carbon emission certificates underpinned the switching from coal to gas since summer. On yearly average, demand for gas for power generation dropped -3% YoY.

32 Final gas demand decreased in 22 out of 28 MSs. The largest demand reductions were observed in MSs with large industrial sectors dependant on gas.

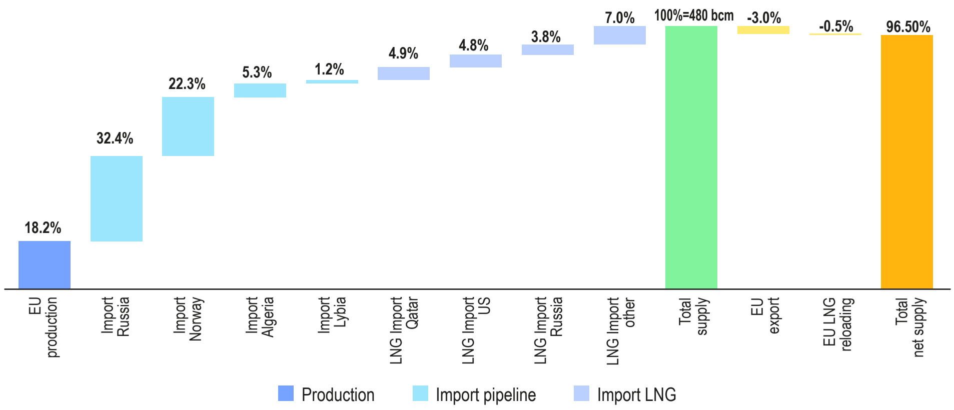
2.1.2 Supply developments

45 The supply of gas to EU markets went through a sequence of rebalances during the course of 2020. LNG deliveries reached record highs in the first semester and heavily plunged afterwards. Pipeline suppliers adjusted to the varying LNG import records in turn. Moreover, the demand shock caused by COVID-19 deeply depressed prices in spring and summer, prompting gas producers to seek an equilibrium between maintaining volumes and safeguarding market returns.

46 The drop in yearly demand forced some supply reductions from most gas supply origins. In addition, the high UGSs levels at the beginning of the injection season and the larger than average withdrawals during the second semester contributed to limit imports (UGS net stocks lost 30 bcm YoY). In relative terms, Libyan exports fell most (-21% YoY).

47 Reliance on EU-external gas continued to increase as domestic production continued to decline (-20% YoY). EU and UK gas production accounted for 18.2% of total supplies, which is a drop of approximately two percentage points in supply share YoY. A lower production cap in the Netherlands[33] and two-digit reductions in production volumes all across UK, Romania, Germany, Italy and Denmark[34] explain the decrease. In the Energy Community area also Ukrainian gas domestic production declined by 2% YoY. In the mid-term, however, the gas sector's transition into low-carbon gas is likely to help to decrease the EU's dependency on energy imports[35]. Figure 2 shows the EU supply portfolio per origin in 2020.

Figure 2: EU and UK gas supply portfolio by origin – 2020 (100% = 480 bcm) – %



Source: ACER calculation based on International Energy Agency and Eurostat.

48 Sales by the main gas supplier to the EU, Gazprom, dropped to 155 bcm (-15% YoY) due to reduced EU demand and the LNG supply glut during the first semester. The high gas storage stocks at the start of the injection season also restricted its total yearly deliveries. All these factors combined ensued extremely low prices in spring and summer, which prompted a limitation in Gazprom's shorter-term gas sales at its electronic sales platform (ESP) due to the reduction in its margins[36]. However, the Russian company's exports recovered during the last quarter, to counterbalance the dropping EU LNG imports and to fulfil some long-term supply commitments that had been deferred by EU buyers[37]. Eventually Gazprom covered about 32% of EU supplies, 3 percentage points down YoY.

33 The Groningen production cap was set at 11.8 bcm/year for the 2019/2020 gas year, the lowest ever. The field produced 54 bcm/year in 2013. The Dutch government has announced that the field will be shut down in mid-2022. UK production totalled some 32 bcm, a 17% drop YoY.

34 Denmark approved to cease all domestic production of oil and gas by 2050, which for gas accounted for 1.5. bcm/year in 2020. The infrastructure will be used at the end of the production phase for carbon storage and hydrogen production.

35 The latest ENTSOs TYNDP scenario report as well as the EC hydrogen strategy supply scenarios, foresee gas import reductions of at least 20% on EU average in the long-run. One of the ENTSO's scenarios points to a reduction of 70% in 2050, considering the total falling EU gas demand coupled with rising domestic production.

36 Revenues collected by Gazprom from EU gas sales are estimated to have dropped by approximately 40% YoY. ESP platform sales, plus direct hub trades, accounted for 11% of Gazprom deliveries to the EU in 2020.

37 In accordance to IEA data, the country's total gas production rose by 25% between the second and fourth quarter of the year, a seasonal swing almost three times larger than in 2019.

49 Norwegian pipeline supply was maintained on average at similar levels as in 2019, despite larger production swings between quarters. Due to their lower marginal production and transportation costs, Norwegian suppliers kept offering a relevant source of supply flexibility to North West Europe (NWE).

50 Algerian pipeline supply dropped 3% YoY. Sonatrach's still partly oil-indexed supply contracts had to compete with massive LNG deliveries to the Iberian Peninsula and Italy in the first semester as well as with heavily depressed hub prices in the second and third quarters. Rising domestic gas consumption in Algeria has also been a driver of lower gas supplies delivered abroad. Algerian exports partly recovered at the end of the year, when the prices of its contracts became more favorable – and its buyers had to fulfill take-or-pay clauses.

51 LNG deliveries accounted for their second ever maximum, although they were down 5% YoY. Flows from the US escalated in the first quarter, above all targeting Spain and the UK. However, from late spring and across summer, lots of US LNG exports to the EU were halted because the price spreads with European hubs were not attractive enough to cover for shipment rates.

52 Gas exports from the EU into Ukraine rose to 15.9 bcm (+12% YoY), backed by lower hub prices and the increased interest of EU shippers to use Ukraine's ample UGS facilities. Ukraine kept abstaining from purchasing Russian gas, whereas the total transits across its system into the EU were shaped by the terms of the five-year agreement signed in December 2019 (see an expanded analysis in Section 2.2).

53 In December 2020, the Trans Adriatic Pipeline started to deliver Azerbaijani gas to Bulgaria, Greece and later in 2021 to Italy, adding another supply origin source and lowering the concentration of the EU market. The corridor is dimensioned in its initial phase to flow up to 10 bcm/year and will diversify the supply options of South East European countries.

54 The continuous adaptation to hub indexes and direct hub sales by upstream suppliers kept increasing the share of hub-price based supplies. In 2020 those accounted for approximately 80% on average across Europe, although there are still differences among regions[38]. Interestingly, a continued switch in gas trading currency to euros was observed, with the share of the contracts for delivery at EU gas markets signed in euros now assessed at 64% of supply[39].

38 See the IGU Gas Price 2020 report showing results per EU region and also including selected EnC CPs.

39 The share has increased from 34% in 2018. This trend backs the EU push of making the euro currency more relevant in global financial markets.

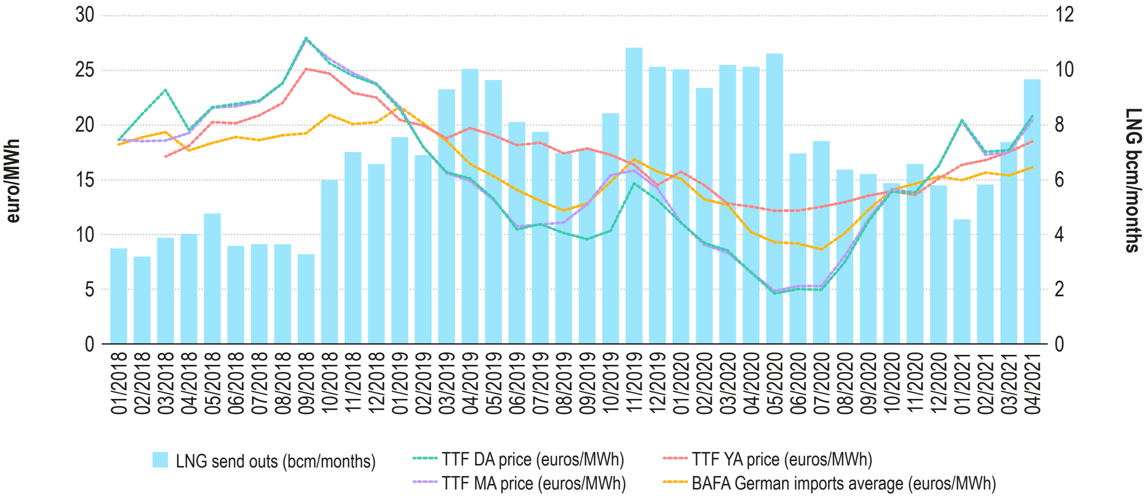
2.1.3 Gas price developments

55 The demand shock caused by the COVID-19 lockdowns, along with record LNG availability, moved EU gas hub prices to all-time lows by mid-2020. Tumbling prices of other energy commodities and high UGS stocks at the beginning of the injection season contributed to the very low-price sentiment.

56 However, hub prices recovered from the third quarter, as a result of improving demand and lessening LNG deliveries. At the end of 2020, following a cold weather wave that vastly shifted LNG cargoes away to Asia, EU hub prices had climbed beyond 2019 levels.

57 As shown in Figure 3, a trend of low gas prices had begun by the end of 2018 and continued across 2019, chiefly as a result of soaring LNG imports. In May 2020, with monthly demand collapsing at more than 15% YoY due to COVID-19, EU spot gas was sold at less than 4 euros/MWh, its lowest value ever and for the first time concurrently below US and Russian hubs, the typical floors of the global market.

Figure 3: Evolution of TTF spot and forward hub prices vs LNG imports – January 2018–April 2021 – euros/MWh – bcm/month



Source: ACER calculations based on GIE and ICIS Heren.

58 Figure 3 also shows the considerable premium that forward hub products exhibited against prompt ones, which anticipated gas price recovery once the economies were to recover. Forward products' support levels were mainly built on US Henry Hub futures and on the appraisals of the gas prices that would trigger a switch from coal to gas for power generation. The latter included emission allowances' evolution expectations. Overall, the price gaps among gas products of different durations propped up hub-traded volumes, as market participants sought to hedge positions at the organised markets.

59 The swings in market fundamentals experienced throughout the year caused record volatility in gas price[40]. The increasing penetration of intermittent RES-E for power generation, which either displaces or requires CCGTs extra production and influences in turn spot gas price formation, also contributed to the high levels of gas price volatility. Conversely, the prices of prevailing long-term gas supply contracts remained flatter overall, depending on their specific price formulas and time-lagged indexations. Some of those contracts became slightly cheaper than prompt hub products at the end of the year, as Figure 3 also illustrates.

60 At the global level, strong gas price correlation among regions was largely maintained. Price movements across the various global gas areas were kept well-aligned via rising LNG trade and inter-regional hub hedging. This implies that EU gas hub prices are increasingly driven by global supply and demand equilibriums and that European prices impact price formation in other global regions. Section 2.2.3 offers more considerations about LNG global markets and includes an overview of international gas wholesale price indexes.

40 Volatility measures how large the price swings around the mean price are. In 2020 it reached more than 100% per annum for day-ahead and 65% per annum for the month-ahead products in EU hubs average, the highest level across the decade. Price volatility at a selection of EU hubs can be consulted in the MMR data portal CHEST.

61 Finally, the correlation of gas prices with other energy commodity prices was diverse, as the demand scenario of each commodity was uneven:

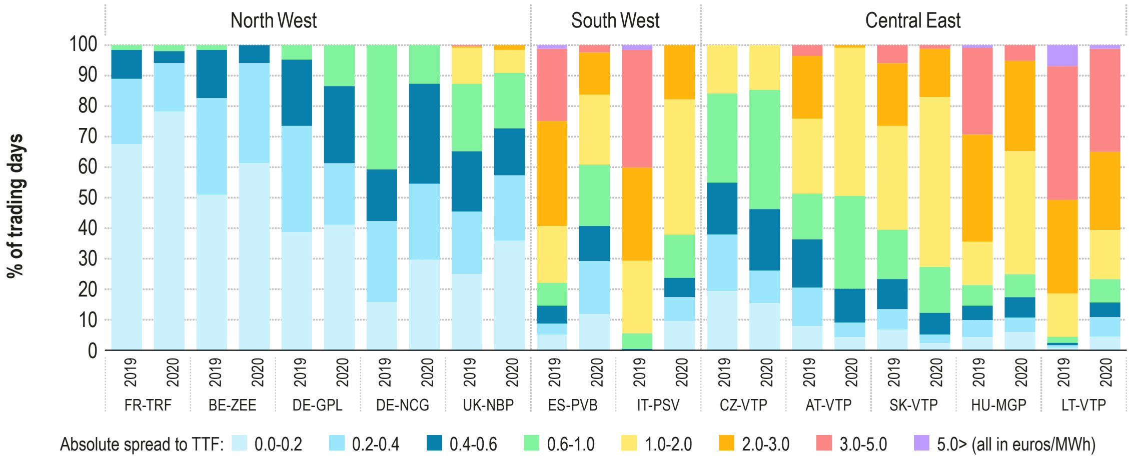
- Electricity prices shrunk in spring and summer months due to lower demand and a rising share of RES-E generation. As did gas prices, so power prices also recovered from the third quarter.
- Coal prices, together with the price dynamics of carbon emission rights, kept heavily influencing the gas price formation. This is because coal and gas compete to set marginal power prices across the EU. The soaring prices of carbon emission rights restricted the profitability of coal-fired generation from the third quarter of the year, while reinforcing the demand in gas for CCGTs. That situation triggered extra upward pressure on gas prices after the summer.
- The correlation between oil and gas prices kept weakening as oil gradually loses ground in gas supply contracts' indexations. As amply enunciated in the media, spot oil prices plummeted in spring, when they even reached negative values in some days of April amid sinking demand and constricted storage capacity, together with other financial aspects.

2.1.4 Hub price convergence

62 The unprecedented price decline experienced by EU gas markets in 2020 was overall combined with a stronger price alignment between MSs' gas hubs. Trading platform prices got closer on yearly average, and chiefly during the spring and summer months, when the lower demand caused by COVID-19 combined with ample LNG deliveries and high UGS stocks brought an excess of supply offer that smoothed regional price differences.

63 Figure 4 compares the evolution of price convergence between a selection of hub pairs, specifically analysing the number of days when the day ahead product's price gap vis-a-vis the Dutch TTF hub benchmark stayed within predefined ranges.

Figure 4: Day ahead price convergence between TTF and selected EU hubs – 2019–2020 – % of trading days within given price spread range



Source: ACER calculations based on ICIS Heren and national exchanges.

64 Price convergence, as well as price correlation remained the highest across the North West of Europe, where price differences remained well below 1 euro/MWh for most trading seasons. Hub spreads in that region commonly remained below transportation costs (see also Figure 41) despite the expiration of some historical long-term contracts. The excess of capacity of some shippers in those long-term contracts in the past led to short-run marginal cost (SRMC) bidding strategies between hubs, which had favoured hub price convergence. Record LNG deliveries and flexible North Sea supplies sold at quite similar prices at all the regional hubs, together with the structural fostering of hub trading at the regional level were key limiting factors for price decoupling.

65 While Figure 4 compares all EU hubs against the TTF benchmark, price convergence tends to be stronger between adjacent pairs of hubs within the same region. This is due to closer market fundamentals within a region as well as to lower cross-zonal transport tariffs[41]. At any rate, Central and South Eastern hubs, as well as Mediterranean and Baltic ones, tend to show a higher absolute price than TTF most of the time. These gaps arise from the specific interplay of marginal supply and market opportunity pricing[42] at each of the individual hubs, shaped by structural market aspects. Transportation tariffs further play a role. Section 4.1 offers further considerations on the price formation subject.

66 As mentioned, an advancing price alignment trend was observed across the year. The improvements in price convergence were notable at the Baltic, Italian and Spanish hubs, which as presented in Figure 4, reduced their price gaps to TTF below 1 euro/MWh with higher frequency. These markets have in common the capacity to import LNG. In various periods those hubs turned out cheaper than other NWE counterparts. For example, the Italian hub unusually quoted at a discount to the Austrian hub, by over 1 euro/MWh, across the summer months due to extra LNG imports[43]. Also some CEE hubs such as the Hungarian or Slovak improved their price convergence YoY, assisted by ample underground storage reserves, including easier access to the Ukrainian UGS sites.

67 Although some short-term demand recovery post-COVID could offset parts of the convergence gains observed in 2020, the building blocks of hub price convergence, like higher infrastructure availability, market liberalisation and broader accessing to LNG are likely to continue contributing to stronger price alignment in the future. The expiration of some long-term legacy contracts could partly counterbalance those effects, by ensuing reduced SRMC bidding. However, sunk costs are not only distinctive of historical LTCs, as annual capacity booked at auctions platforms, if in excess, can be also used to optimise short-term price arbitrage. More considerations on the subject are discussed in Section 5.2.2.

41 Convergence and correlation values between regional hub pairs further than vis a vis TTF are available in the MMR data portal CHEST.

42 Marginal supply denotes the price signal sent by the last (i.e. most expensive) supplier sourcing at the hub. It commonly disciplines the prices of the rest of competitors, which tend to offer some discount to secure sales and maximise revenues. This is the so-called market opportunity price.

43 On yearly average, the Austrian VTP price discount to its Italian PSV counterpart averaged 0.5 euros/MWh, in 2020, compared to 1.5 euros/MWh in 2019. Also unusually, the Hungarian hub prices fell for most of November below TTF due to ample supply in the region, including imports from Ukrainian storages.

2.2 Infrastructure and system operation developments

68 This section reviews the main gas flow and infrastructure developments that occurred during the year and complementarily includes an assessment of LNG and UGS market developments.

2.2.1 Physical gas flows across EU borders

69 Figure iv in Annex 1 offers an overview of the EU and EnC gas cross-border flows in 2020. In the face of supply rebalances and a highly volatile price development throughout the year, the widely interconnected EU gas systems proved dynamic and resilient to accommodate flows in response to short-term signals.

70 Pipeline imports are increasingly subject to liquefied gas delivery records. Across the first semester of the year, record high LNG imports pressed pipeline supplies down. However, from September and across the first months of 2021, pipeline deliveries ramped up to counterbalance lower LNG imports when liquefied gas started to be pushed away into Asia.

71 Gas supplies across Nord Stream marginally increased YoY. The Baltic Sea offshore pipeline is the corridor that operates at the highest capacity (95% on average) among the four main Russian supply routes. Conversely, the termination of the long-term capacity contract of the Russian producer atthe Europol pipeline in May 2020 led to some lower use of the Belarus-Polish supply corridor (-7% YoY). Despite that contractual expiration, ample capacities kept being booked in auctions, as further discussed in Section 5.1.

72 Russian gas flows across the Ukrainian corridors were modest and overall limited to the thresholds signed in the five-year agreement[44]. The 55.8 bcm nominated were eventually about 40% lower than the volumes transited in 2019[45]. The drop was chiefly due to the reduced priority of the supply route, including the re-routing of some flows towards SSE across the new Turk Stream[46]. Reduced Central East Europe demand and the use by Gazprom of large EU UGS stocks were also contributing factors. Even so, at selected winter months, Gazprom acquired extra capacity at the Ukrainian interconnectors to cope with additional gas nominations of its EU buyers.

73 As the Ukrainian-Slovak route loses ground, Germany is acquiring a more relevant transit role for transporting Russian gas to other parts of the EU. This role is expected to increase further once Nord Stream 2 comes online. The second string of the EUGAL pipeline started operation in April 2021, further amplifying the export capacity into the Czech Republic (the corridor totals 55 bcm/year in total). Some of that gas flows reached Austria via the Czech-Slovak route, replacing direct deliveries at the German-Austrian border. Notwithstanding that, the surge in LNG imports of some neighbouring MSs led to some declines across other German supply routes in recent years. For example, flows from Germany into France have fallen by 35% since 2018, as French LNG imports have soared by more than 60% since then.

74 TAP flows were initiated at the end of 2020 across Greece and Bulgaria, whereas also some LNG deliveries from the Greek Revithoussa terminal reached Sofia[47]. These developments underline the supply diversification taking place in the region. In fact, Bulgaria and Greece have contractual commitments with Socar at TAP for 1 bcm/year each, which could halve Gazprom market share in the region[48]. The new ROHU interconnector has also enabled Romania to receive additional reverse flows from Hungary since October 2019, as the case study in Section 4.3.1 further elaborates.

75 The flows from the Continent into the UK across the IUK and BBL interconnectors were dependent on LNG delivery patterns, and on average fell by more than 15% YoY. Since the gradual expiration of various long-term contracts in the last years, total flows have become more price-responsive, but hub spreads do not usually cover for the transportation costs of new capacity (which in fact rose YoY).

44 By the end of 2019, Ukraine and Russia had signed a five-year agreement setting minimum take-or-pay transit flows across the Ukrainian network: 65 bcm/year for 2020 and 40 bcm/year for 2021–2024.

45 While nominations reached 55 bcm, physical flows into the EU amounted to 38 bcm. The Ukrainian TSO reports that 45% of the imports from the EU into Ukraine were netted as reverse backhaul, after the service first became available in early 2020.

46 E.g. following the expiration of transit contracts at the Romanian system, Gazprom redirected part of the previous Ukraine-Romania-Bulgaria flows into Turk Stream, which eventually transited 5 bcm across the year.

47 These are expected to be further expanded once the IGB interconnector linking both MSs starts operation in 2021.

48 Partly affected by these diversification attempts, the Bulgarian government announced in March 2020 that it had renegotiated the price indexation of its supply LTCs with Gazprom linking a significant part to hubs quotations, what lead to a 40% price discount YoY.

76 Combined flows into Italy across the Austrian and Swiss corridors decreased 9% YoY amid healthy LNG deliveries into the transalpine country. Overall, the larger imports of LNG across the first semester also reduced pipeline sourcing needs in Spain and France. The three MSs' northern supply routes tend to be relatively flexible in terms of operation, but face comparatively high transportation costs. Furthermore, TAP is earmarked to serve 8 bcm/year of Azeri gas to Italy (i.e. 12% of its demand). Remarkably, following TAP's entry into operation in January 2021, PSV hub prices quoted at a discount to TTF.

77 Finally, as for the EnC CPs, Ukrainian imports from the EU rose by 12%, with the Slovakian route leading, followed by Hungary and Poland. Some 45% of the total Ukrainian imports from MSs were netted by back-haul flows following the implementation of common interconnection agreements. Section 5.4 discusses the subject further.

2.2.2 Infrastructure investment

78 Across the year, new relevant gas infrastructure took ground or consolidated its operation, contributing to enhance supply competition in various MSs. Some of the new large supply corridors are relevant enough to affect the competitive framework at the regional level.

- *Turk Stream's* second line – Balkan Stream – delivered 2 bcm/year to Bulgaria, reached Serbia in early 2021 with plans to advance to Hungary and Baumgarten[49]. The line has a capacity of 20 bcm/year intended to divert exports that used to be transported via Ukraine.

- The *Southern Gas Corridor initiative* started to bring volumes from the Caspian and Middle Eastern regions to the EU in December 2020. It reached Greece and then Bulgaria, and in January 2021, Italy. The TAP line has a capacity of 10 bcm/year, which can be doubled.

- *Nord Stream 2* kept facing delays associated with its political controversy. It is expected to enter into operation in 2021, adding 55 bcm/year of extra import capacity. An element in the discussion is its likelihood for transporting hydrogen[50].

79 Next to these main corridors, various other investments moved forward. Since October 2020, the ROHU interconnector has enabled additional reverse flows of Romanian and future Black Sea gas into Hungary.

80 The Baltic Connector pipeline linking Finland and Estonia was also commissioned in the beginning of 2020. It offers 7.2 bcm/year of bidirectional capacity, the dominant physical sourcing direction being into Finland so far. In addition, the new Baltic Pipe, set to connect Denmark and Poland to Norwegian gas fields, aims to start its operation by October 2022, with a capacity of 10bcm/year[51]. Further expansions on the Polish-Ukraine route could allow Ukraine to access LNG imports from Poland. Moreover, the 2 bcm/year bidirectional interconnection between Poland and Lithuania, GIPL, is planned for 2022.

81 With regard to LNG, the Croatian Krk terminal entered commercial operation in January 2021, with a nominal regasification capacity of 2.6 bcm/year. The terminal aims to enhance regional competition by enabling access to LNG. Germany and Greece have also announced plans to operate new LNG terminals by 2023. In addition, some terminals in France, Belux and Poland are exploring capacity expansions, driven by market interest (an overview of all existing and planned EU LNG terminals is provided in Figure 6).

49 Supplies to Bulgaria, Greece and North Macedonia started at the beginning of 2020, whereas flows into Serbia commenced in January 2021. Hungary and Austria-Baumgarten (the main market targets) are expected by end 2021 (6 bcm/year contracted) and 2022 respectively.

50 The scenario is theoretically possible, although is materialization is still in the distant future. See further considerations for example in this article.

51 A long-term supply contract of 10 bcm/year between the Polish incumbent PGNiG with Gazprom across Yamal is to expire at the end of 2022 (the commodity contract is separated from the transit one that concluded in May 2020). The company signed a 6.4 bcm/year contract with the Danish producer Orsted from 2023 while it plans to expand its own production in the North Sea.

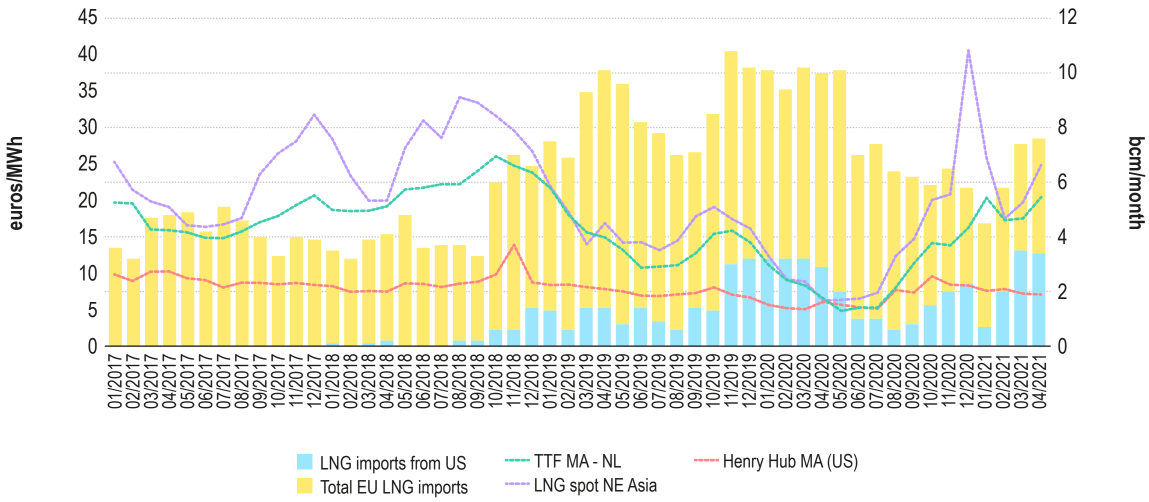
82 Some independent assessments estimate the cumulative investment for all new natural gas pipeline projects proposed today at around 53 billion euros, and additional 13 billion euros for new LNG facilities or expansion of terminals[52]. However, many of the projects will face review, due to incomplete market interest, triggered either by a reducing role of conventional gas or by lower cross-zonal transits following the gas decarbonisation shift. A challenge for the sector is how to address the risk of stranded assets.

83 In this respect, the EC proposal to revise the TEN-E Regulation proposes that new conventional natural gas projects shall no longer be eligible for EU funding. The EC proposal, which is still being debated by the Council and the Parliament, is to solely finance low-carbon gas infrastructure as well as, chiefly, electrical interconnectors and the deployment of offshore renewables[53]. Before this new Regulation enters into force, a last round of PCI gas projects assessed under the former methodology is foreseen towards the end of 2021 (although some selection criteria will be reviewed, the list will still include conventional natural gas projects).

2.2.3 Analysis of LNG market developments

84 The volumes of LNG delivered into the EU throughout 2020 were highly determined by the developments at international gas markets. On the one hand this is because liquefied gas has significantly risen its share in global gas trade. On the other hand, LNG has enhanced its end-point flexibility[54], while the EU has acquired a position of global market of last resort[55]. Eventually, LNG imports into the EU-27 and the UK decreased by 5% when compared to the highest-ever deliveries of 2019. Figure 5 illustrates three quite different market dynamics throughout the year.

Figure 5: Comparison of international wholesale prices spreads vs EU plus UK LNG imports - 2017–April 2021 – euros/MWh and bcm/month



Source: ACER calculation based on GIE ALSI and ICIS Heren data.

52 See Euro Gas tracker report 2021 from the Global Energy Monitor for a detailed list of the projects considered. Those are projects that have appeared in corporate or government plans, or in news reports, in either pre-permit or permitted stages. Together they would imply a 35% increase of todays' gas infrastructure capacity.

53 The revised TEN-E policy announced in September 2020 updated the infrastructure categories eligible for financial support. It set a new category to back new and repurposed hydrogen transportation and storage infrastructure. It will finance as well electrolysers above 100 MW. Other forms of low-carbon gas are also assisted during a transitional phase. Finally, a smart grid category was also added to back projects enabling the integration of low-carbon gases into the gas distribution grid.

54 LNG accounts for 35% of global gas trade (circa 500 bcm/year, alike to EU-28 consumption) and is forecasted to account for 50% by 2040. Total LNG trade rose by 1.5% YoY, with spot cargoes accounting for a record of 37% of all transactions. Qatar was the world biggest exporter in 2020 (22%), followed by Australia (21%), the US (13%) and Russia (7%). Japan was again the major global importer (21%), followed by China (19%, China imported +12% LNG YoY, despite the Power of Siberia pipeline is ramping up and delivered 4bcm) Korea (13%) and India (8%, +15% YoY). The EU and the UK account for circa 20% of global LNG imports, with Spain, France and the UK as leading markets.

55 There are several reasons for the EU to have assumed such a role: 1) EU's ample UGS stocks and regasification capacity (i.e. LNG terminals could meet 220 bcm/year or 45% of total demand) 2) Spare CCGTs capacity that can displace coal-fired generation under the right price signals 3) Liquid EU hubs acting as key price benchmarks for hedging global LNG portfolios and 4) The shift of global LNG markets into more flexible supply terms coupling with EU terminals' third party access provisions that facilitate dynamic imports.

- Until early summer, LNG deliveries into the EU remained solid, hitting monthly highs. They benefitted from the demand slowdown in the Asia-Pacific region and from extra LNG global production capacity. Large deliveries contributed first to fill up UGSs and LNG storages and then to feed CCGTs, displacing coal.

- COVID-19 effects over demand became more evident from June. Prices plummeted, limiting the attraction for LNG sellers, while filled UGSs were unable to accommodate extra deliveries. Besides, the gas absorption capability of CCGTs was restrained by limited power production and the leading RES-E shares. Across summer, some LNG producers, chiefly US ones, set in turn a supply-side response limiting – if not fully cancelling – their LNG exports due to the unprofitability of their margins[56].

- In the last part of 2020 and early 2021, recovering gas consumption in the Asian-Pacific region pressed global spot LNG prices up and drew cargoes away from the EU. The extra Asian demand was for a big part weather driven, but also assisted by low nuclear availability and milder COVID-19 impact on the economies of the region. Consequently, the EU's LNG imports diminished, with total deliveries falling by 40% when compared to the same period one year before. EU spreads with Asia began to ease from March 2021 onwards and EU imports have recovered accordingly since then.

85 LNG has become a chief vector for balancing regional demand with global supply and for driving price integration among world regions. Figure 5 underlines the linkages between the LNG volumes imported into the EU and the spot price spread with North-East Asia. Historically, the spot price gap between both regions had shown a pronounced seasonal component, with higher values in winter. However, since 2018 price convergence has become stronger due to a global surplus of LNG production. Nonetheless, when Asian demand intensifies, global LNG supply may become tighter and regional spreads may rise as the developments of the winter 2020/2021 revealed[57].

86 In fact, the average spot spread between EU and North-East Asia moved from 0.5 euros/MWh in 2019 to 3.2 euros/MWh in 2020. The regional price differences chiefly surged in December, to six years' highs, exacerbated by outages in Australian production[58], the Panama Canal congestion and limited charters' availability[59]. The latest factor constrained reloads from Europe into Asia, proving that even if global markets are gradually getting more integrated, congested physical links and supply restrictions can increase regional price differences.

87 Figure 5 also shows the evolution of the volumes of LNG imported from the US, proving that the relative position between the EU's hubs and US Henry hub more and more drives the volume of US LNG delivered into Europe. As referred in Section 2.1.2, lots of US LNG exports to the EU were halted in late spring and summer, as the regional price gap was not sufficient to cover for shipment costs.

88 On average, the use of the EU terminals' regasification capacity was 45%, two percentage points down YoY. However, ample differences in use appeared among MSs and plants. The largest relative utilisation was observed at terminals in the Baltic Sea and in Italy; a comparison of the terminals nominal capacity and their yearly average use is provided in Figure 6.

56 During the summer 2020, more than 200 US cargos were cancelled due to uneconomic short-run margins for delivery in Europe and Asia. Despite that, US global LNG exports rose by 30% YoY, boosted by the start-up of some new liquefaction trains.

57 Despite that 120 bcm/year of extra LNG global production capacity is expected until 2025, the forecasted Asian LNG demand surge could counterbalance that. Another relevant factor determining the regional spreads is that oil-indexed LNG contracts are still dominant in the Asia-Pacific region, even if the IEA estimates that 20% of them will expire in the course of the next 5 years. The prices of those contracts tend to act as a ceiling to spot LNG ones, although at the end of 2020 they were even cheaper, benefiting from their lagged time indexations.

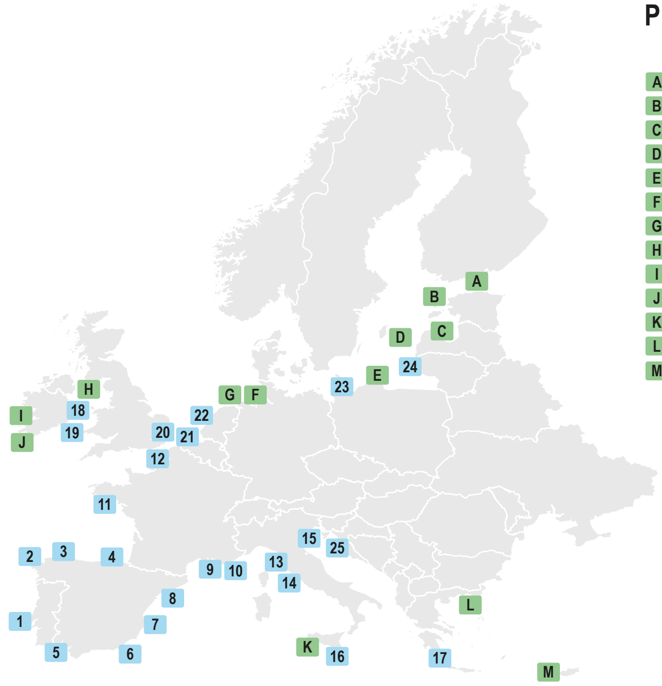
58 According to IEA estimates, as much as 10% of global liquefaction capacity stopped production due to unplanned outages during some periods of the third quarter of 2020.

59 Charter rates rose fivefold YoY across December 2020, intensifying the price spread surges. This bumped in turn new LNG carriers' construction orders.

Figure 6: Overview of EU LNG terminal and UGS capacities per MS – 2020

LNG terminals

	Name	Storage capacity (x 1000 m³)	Regas-sification (bcm/y and %)
1	Sines	390	6.4 (82%)
2	Mugardos	300	3.7 (40%)
3	Gijón (Musel)	300	7.0 (N/A)
4	Bilbao	449	7.1 (73%)
5	Huelva	618	12.0 (35%)
6	Cartagena	585	12.0 (25%)
7	Sagunto	598	8.9 (19%)
8	Barcelona	758	17.4 (21%)
9	Fos-Tonkin	80	3.1 (57%)
10	Fos Cavaou	330	9.6 (51%)
11	Montoir	360	10.8 (67%)
12	Dunkerque	586	16.6 (24%)
13	Panigaglia	40	3.8 (67%)
14	FSRU Toscana	137	5.3 (63%)
15	Porto Levante	250	7.3 (93%)
16	Delimara	125	0.7 (N/A)
17	Revithoussa	225	8.6 (35%)
18	Dragon	160	7.6 (47%)
19	South Hook	752	20.8 (54%)
20	Isle of Grain	1026	20.6 (23%)
21	Zeebrugge	562	14.2 (33%)
22	Gate	540	14.8 (54%)
23	Świnoujście	320	5.2 (72%)
24	FSRU Indep.	167	4.0 (50%)
25	Krk Island	140	2.6 (N/A)



Planned terminals

	Name
A	Hamina
B	Paldiski
C	Skulte
D	Kundzinsalas
E	FSRU Polish Baltic Sea
F	Brunsbüttel
G	Wilhelmshaven
H	Port Meridian
I	Shannon
J	Cork
K	Porto Empedocle
L	Alexandroupolis
M	Vassiliko

Source: ACER calculation based on GIE (2020).

89 The number of cargoes that headed towards each plant was affected by a combination of factors, including the importance of liquefied gas to source the total gas demand in the adjacent market, the liquidity, price levels and ease of access to the linked hubs', and last but not least, the dominant commodity and capacity contracting patterns.

90 At the terminals with an easier entry to most liquid hubs, LNG is increasingly used as a competitive flexible instrument to balance portfolios and hedge prices on shorter horizons. This makes LNG deliveries, as well as spot cargoes and short-term berths contracting, more price-responsive while also more volatile[60]. Even so, some long-term contractual positions persist in the majority of plants, as instruments that secure capacity while backing up trading opportunities.

91 Longer-term contracts are more often marked at the supply and capacity portfolios of gas shippers with a larger reliance on liquefied gas, which are in need to limit acquisition risks. This increasingly includes LNG producers for the capacity side[61]. Also, longer bookings are dominant at newest and at exempted terminals, to better back the terminals' business cases[62]. The split between fixed and variable charges also affects the plant's booking profiles. Lower fixed costs tend to be associated with higher long-term bookings, while in turn the terminals with higher shares of long-term reserved capacity tend to be used more. The global extra LNG supply availability has also aided longer booking strategies in recent years.

92 The use profile of each terminal is shaped as well by the services and the technicalities that they offer and, importantly, by the regulatory aspects that govern their access. The latter aspect attracts increasing discussion, as cross-terminal competition is intensifying across the EU.

60 E.g. at NWE terminals, the imports of LNG plummeted by 40% YoY in the winter season, while at Southern and Eastern ones LNG imports failed by 20% in the same period.

61 LNG producers are rising their interest in capacity acquisition; for example the Qatari incumbent controls various UK terminals and the Belgian Zeebrugge. Also contractors of long-term shipment positions are less exposed to the charters' price volatilities.

62 At various new and most of the exempted terminals, as well as in Zeebrugge and Montoir, all primary capacity has been allocated via long-term contracts. This tends to result in higher booking and use concentration ratios.

93 Discussions about the rightness of the diverse access regimes, including the fairness of their tariffs are alive, raising questions about some degree of harmonization[63]. Today, the twenty regulated and six exempted terminals in the EU and the UK (the latter comprise around 35% of the total regasification capacity) coexist without harmonised rules. LSOs make use of distinct access frames to assign their primary and secondary capacities, with a notable diversity of tariffs; the standard unloading, storage and regasification bundled products, plus the entry charge into the gas network, ranges from 0.35 euros/MWh in Lithuanian Klaipeda to more than 4 euros/MWh in the Italian Porto Levante (see tariff benchmark in Figure vi in Annex 1).

94 The Third Package calls for guaranteeing unbundled and non-discriminatory third-party access to the regulated plants[64], together with implementing congestion management procedures and enhancing the transparency of the services' capacities and tariffs[65]. Not all these provisions are applicable to the exempted terminals, which can decide their own allocating mechanisms and rates.

95 Within this wide-ranging setting, a plethora of primary and secondary capacity allocation mechanisms (open seasons, auctions, FCFS, UIOLIs either applied at scheduled or continuous subscription windows) and services (bundled or not, and for a dissimilar duration of slots, with a flexible use or not) are implemented at NRAs' and LSOs' discretion. A recent study commissioned by the EC benchmarks in detail the distinct access regimes, questioning how those affect terminal's use or may hamper competition[66]. The study proposes standardising the access products and their allocation conditions to address possible undue competition issues (auctions, with as low reserve price as possible, are backed).

96 Conversely, other stakeholders endorse lowering to the minimum the accessing standards and encourage more flexibility in the offering of services to optimise the plant's use[67]. In their view, the concerns that motivated regulated third party access have been generally reduced, while the terminals' and the hubs that they provide access to are competitive enough. LSOs should in their view strive to respond to the two main reasons that lead LNG shippers' choices when choosing a terminal; the tariffs of the services and the option to flexibly access liquid hubs. More considerations are offered in the Recommendations section.

97 A relevant example comes from Spain. There, the introduction of a common access regime based on auctions across all the six terminals, which since April 2020 are operated as a single virtual tank, together with a broader offer of services and somehow lower access tariffs, has eased operations and contributed to the increased liquidity at the Spanish hub. The trading of LNG spot products in the six separated Spanish terminals had been available at the Spanish gas exchange since 2019. However, the liquidity of those products was quite low. After the virtual tank setting, the possibility of trading one single LNG spot product has resulted in a boost of liquidity (see trade volume results in section Figure 20).

98 Liquefied gas is projected to keep increasing its share in the EU gas mix for some years, as a means to diversify supplies and promote price competition. The extent to which these projections materialise will depend on the growth path of global LNG production and its attraction to the Asia-Pacific region. The sector is moving towards more decarbonisation; various cargoes of carbon-neutral LNG – i.e. the emissions associated to conventional cargoes were offset through carbon credits[68] – were traded across the year. The technicalities to import hydrogen could become more complex due to, among other reasons, boil-off aspects. The first global dedicated hydrogen receiving terminal has already been put in demonstration[69].

63 The TAR NC cost-reflectiveness principle applies to the network entry access but not to the LNG services. However, the code allows for some discounts in the entry charge either for SoS reasons or to stimulate supply competition. Cross-subsidisation between terminals and transmission network users is granted in several systems to further promote the LNG price disciplining effects. Those decisions imply that the terminals' costs get recovered from transmission users (or from national or EU-funds when LNG investors got public support). Tariff competition may also reach the plants' linked cross-corridors. As an example, discussions arise about the final tariffs of GIPL line, which are proposed 50% more expensive into Poland entry direction. This could promote a higher use of the Polish terminal than of its Lithuanian counterpart. Similar discussions are common between Portugal and Spain, or between the exempted Dutch Gate and Dunkerque terminals and the non-exempted Belgian and French ones.

64 See Gas Regulation 715, chiefly articles 15 and 17. Exempted regimes granting are governed by Article 36. The CAM NC does not apply to LNG terminals accessing into the network.

65 GIE has developed a common transparency platform that makes the information more accessible.

66 See recent Trinomics and REKK study for the EC.

67 See for example some positions expressed by the industry at a recent REKK workshop.

68 See further considerations on the subject at GGIGNL.

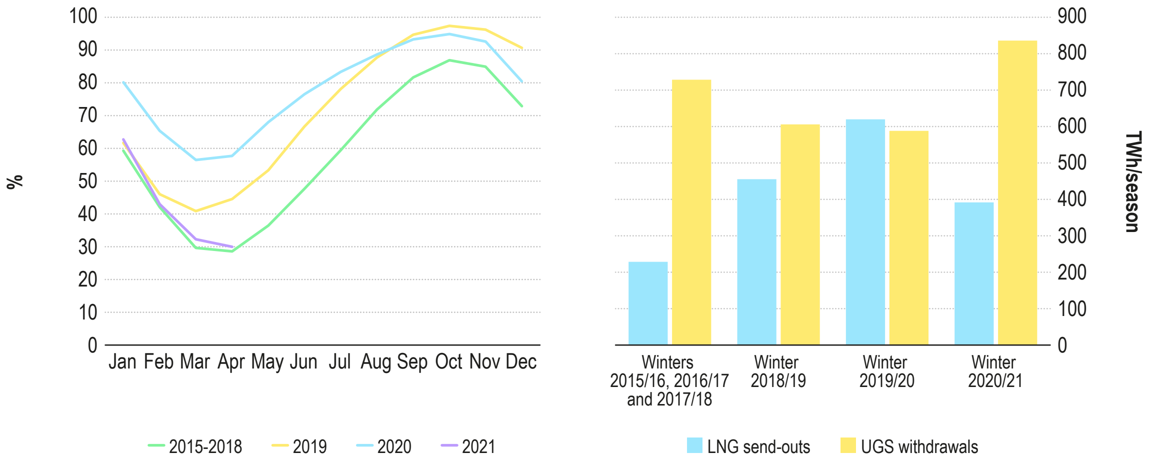
69 The terminal will be used for a demonstration test to transport liquefied hydrogen from Australia to Japan.

2.2.4 Analysis of underground storage facilities market developments

99 UGS facilities play a role in security of supply and in price management, both partially related to the operational timeframe; in the mid-term, storages back seasonal supply flexibility and price hedging, while in the short-term they serve the managing of prompt gas portfolios and spot price arbitrage.

100 The equilibrium between storages' withdrawals and injections is shaped by a combination of factors including the availability of gas supply sources in the market, the technical specificities of the sites, the obligations prompted by SoS regulations as well as by the hub prices, the sites access conditions and the prevailing contracts. All these factors combined led to unprecedented high stock volumes in EU storages across parts of 2020, as the left part of Figure 7 shows.

Figure 7: Evolution of EU storage site levels – 2015 to June 2021 and winter LNG send-outs vs UGS withdrawals – % of EU stock capacity – TWh/season



Source: ACER calculation based on GIE ALSI+ data. Excludes Ukrainian and Serbian sites. EU plus UK maximum storage capacity is around 100 bcm.

101 This extraordinary outcome was the result of a combination of events:

- EU storage sites began 2020 with historical high stocks, brought by a mild winter and abundant LNG deliveries. Both factors continued in the first months of the year, dampening withdrawals[70].

- In early spring, the demand shock induced by COVID-19 further restricted withdrawals, whereas the sites' stocks piled up due to continuous LNG imports. By April 2020, EU UGSs capacity in use almost doubled compared to the 2015-2018 average (+30 bcm more in stock). To these large volumes had to be added the exceptionally high reserves in Ukraine, one third of them backed by EU shippers as the subsection below discusses.

- However, from late summer recovering hub prompt prices – frequently at premium to mid-curve ones – together with fading LNG arrivals and the onset of colder weather favoured withdrawals, which ended up 20% higher YoY. The use by producers of their gas in stock to supply long-term contracts' nominations also contributed to empty UGSs. By April 2021, EU UGSs were emptier by circa thirty percentage points compared to April 2020.

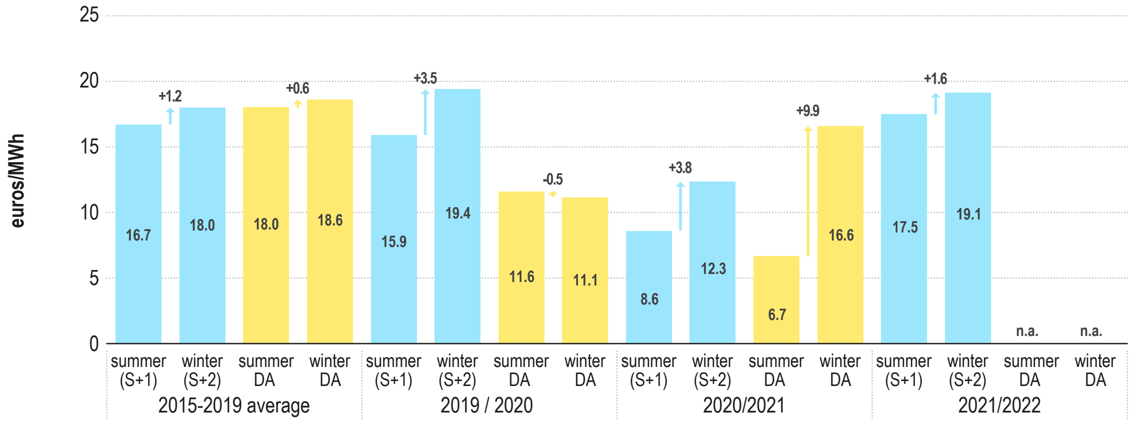
102 These physical movements were driven on the whole by hub products' price signals that reflected the supply and demand equilibriums and their expectations. For example, the lower stocks at the end of the winter 2020/2021 contributed to press the summer season 2021 hub product prices up, because shippers anticipated the need to inject extra gas by then.

70 Another relevant element supporting the high UGS stock levels were the ample injections registered in late 2019, as a hedging strategy against the possibility of Russia and Ukraine failing to set a new transit agreement.

103 Generally, EU UGSs operation strategies have been shifting in most markets towards shorter timeframes at the expense of a reducing mid-term security of supply role[71]. Shorter-term oriented strategies are gaining ground because they better enable to adapt shippers' portfolios to the increasingly elastic gas demand of CCGTs as well as to arbitrate more volatile spot gas prices[72]. A more dynamic offering of UGSs capacities via auctions in shorter-terms, as well as the offering by storage operators of higher flexibility in UGSs operation, is supporting the trend.

104 Furthermore, the financial appeal for mid-term strategies has been decreasing as a result of narrowing seasonal price spreads at EU hubs since 2010[73]. It is true that seasonal spreads surged in 2019 and even more in 2020, when they reached 10-year highs; however, in both years the steeper spreads chiefly came out of prospects for very depressed prices during the summer season instead of price premiums in winter[74]. Seasonal price spreads have tightened once again in 2021 as summer prices rose closer to winter ones due to the extra demand forecasted in summer to fill depleting UGSs. Figure 8 tracks the summer/winter seasonal spreads evolution across the last five years.

Figure 8: Comparison of ex-ante season summer/winter spreads vs actual spot prices at the TTF hub – 2015–2021 – euros/MWh



Source: ACER calculation based on Platt's and ICIS Heren data.

Note: The ex-ante summer/winter spread is calculated as the difference between the Season-ahead+2 and Season-ahead+1 hub product prices, both negotiated on the month of March. The actual summer/winter spread is calculated as the difference between the spot average prices along both seasons.

105 The exceptional circumstances of the year brought new elements to the discussion on how to better guarantee security of gas supply and what the role of UGSs should be. While the supply safety of EU gas systems is assessed as well safeguarded – in fact it has significantly enhanced in recent years thanks to the IGM progression[75] – the COVID-19 effects and more structurally, the irregularity in LNG deliveries, unlocks some concerns; for example the LNG diversion to Asia reduced EU gas supply margins at the end of 2020, even if in all instances SoS thresholds were maintained.

71 Both strategies are interrelated as market participants may initially conclude trades in order to hedge seasonal spreads and physical needs but then arbitrate those contracts short-term, adding profitability to the initial positioning. The expiring of some storage capacity long-term contracts is also contributing to the shorter-term shifting. Even if UGSs price-responsiveness somewhat varies per MS – with merchant-based models being more acute in NWE – most MSs have implemented flexibilities in use to make price signals determinant.

72 Rising prompt price volatility has overall supported the profitability of fast cycle storage assets in the last years, while lower cycle underground gas storage have been more irregular.

73 E.g. from 4 euros/MWh in 2012 to 1.6 euros/MWh in 2021 for TTF, which are around the capacity cost of cycling storage assets. The reasons include lowering total demand on the one hand and higher gas supply flexibility on the other, the latter brought about by enhanced market interconnections, increased access to LNG and less pronounced seasonal gas demand variations.

74 Customarily high seasonal summer/winter spreads are connected to projections of supply tightness in winter, which push winter prices up. For 2019, the low summer prices were mostly the outcome of record LNG deliveries, while in 2020 were due also to record gas underground gas storage stocks and COVID-19 impacts in the economy.

75 ENTSOG assesses that the flexibility of the EU gas system is sufficient, while underground gas storage act as the most relevant assets in the winter season. South-East Europe is the most exposed area, but MSs have sensibly reduced risk of demand curtailment with new infrastructure and enhanced diversity of sources (together with gradually decreasing foreseen demand). See ENTSOG Winter Energy Outlook.

106 The transition towards a carbon-neutral economy in the years to come will prove the future significance of UGSs. Some sites will increasingly be used to store methane to source hydrogen production, while others may end up injecting carbon dioxide generated in CCS procedures. Faster cycle facilities, in particular in salt caverns, can assist to better store and inject green hydrogen produced by RES[76].

107 The extent of EU energy systems' integration will also be crucial to determine the exact role that UGSs will play. The improvements in energy efficiency and the projected growth in electrification can steadily erode gas demand, which would diminish gas UGSs importance. However, decarbonised gases have a potential to be transported and stored at lower cost and in larger volumes than electricity, which supports some UGSs' business cases[77], particularly for those fast cycling storage sites that enable to back the more flexible operation of power-to-gas plants.

Ukraine storage developments

108 Ukrainian underground gas storage sites are becoming an important element for the integration of the country with its adjacent EU gas markets. Ukraine has twelve UGS sites, with a peak storage capacity of 31 bcm. In the course of 2020, the highest stocks were reached in September with circa 28 bcm, following substantial gas injections across the summer months.

109 The interest of EU shippers in using the Ukrainian storage sites has increased in recent years following the revision of the legal and regulatory conditions for using them. The higher presence of storage users[78] has also backed the development of the Ukrainian gas exchange, as Section 4.2.1 discusses.

110 One of the policy decisions that has had a higher impact to increase the interest in Ukrainian UGSs sites utilization is the so called revision of the customs warehouse regime. The revised regime allows non-domestic shippers to store natural gas in the UGSs of Ukraine without paying taxes and customs duties for 1095 days. Trades under the new regime reached 11.3 bcm/year in 2020, rising by a factor of five in comparison to 2019.

111 In addition, reduced short-haul transmission tariffs are applied at the Ukrainian IPs with Poland, Slovakia, Hungary and Romania since 2020 under the condition that the IPs bookings are linked to entries and exits to and from Ukrainian UGSs. A multiplier of 0.66 is applied at the entries into Ukraine, while for the IP exits it ranges from 0.36 to 0.49. In 2020, 6.1 bcms were transported into Ukrainian storages at discounted short-haul tariffs, which represented 22% of total gas stored in Ukrainian sites.

76 Hydrogen and/or methane produced from RES could be injected into underground gas storage and get latter reconverted into electricity to deal with seasonal demand swings or low RES electricity production periods.

77 See cost estimates of gas and electricity transport in footnote 107.

78 457 users were registered in Ukrainian storage sites in 2020, while 29 bcms were traded to change property at underground gas storage in 2020. This is four times more than in 2019 and fourteen more than in 2018.

3 Gas sector contributions to decarbonisation goals

112 The gas sector currently accounts for around one quarter of the EU's carbon emissions[79]. This relative share has slightly increased over the last decade due to the decreasing consumption of coal and oil – still the two major sources of carbon emissions – and specifically the replacement of coal by gas for power generation; a development which contributes to overall lower CO_2 emissions.

113 To deliver a carbon-neutral economy by 2050, the gas sector needs to be fully decarbonised in the next three decades. While MSs have agreed to reduce their 1990-level emissions by 55% by 2030 and the Renewable Energy Directive has set a target of 32% of RES penetration by then, a specific roadmap with mid-term targets for the decarbonisation of the gas sector has not been developed. Some industry associations and research institutions state that if the 2050 targets are to be met, emission reductions by at least 20% compared to 2018 should be achieved by the end of this decade[80]. A drop in gas demand drops will not deliver on this ambition, so natural gas needs to start being increasingly replaced by renewable carbon neutral gases. The parallel reduction of methane leakages is also imperative.

114 This chapter aims to identify potential contributions that the gas sector can make to decarbonisation and identify potential impact on the sector in the years to come. It starts by analysing the recent trends in coal to gas shifting trends in power generation in order to offer a perspective on the role played so far by gas to decarbonise the EU energy system. In addition, information about the presence and the costs of low-carbon gas is presented and subsequently contrasted against their prospects and drivers. Finally, relevant regulatory considerations are outlined, chiefly for those aspects more closely related to market integration.

3.1 Carbon emission reductions from coal to gas shifts

115 Until there is greater penetration of low-carbon gas, natural gas can contribute the most to decarbonisation efforts by enabling the switch from coal to gas-fired power generation. This is because the carbon-equivalent emissions at newer gas-fired plants are, by and large, up to 50% lower than at coal-fired plants for each unit of electricity generated[81].

116 In fact, if the current prevailing EU's coal-fired power generation switched to conventional gas, emission could be reduced by up to 150 $MTCO_2$ per year[82]. This is roughly the amount of the emissions produced by the EU aviation sector. Nonetheless, further system-wide emission reductions need to be achieved, for instance with a RES-E plus flexible gas-fired generation mix[83].

79 This includes Agency estimates about the use of gas in power generation, industry and households in base of combustion reactions, and estimates of methane leakages across the gas supply chain. Carbon emissions per sector are measured in detail by the EEA in its annual inventory. They totalled 3.284 Mt CO_2 equivalent in 2019, a reduction of 24% since 1990.

80 The new RED revision within the fit for 55 Legislative Package expected for the end of 2021 could position on those targets. The EC has so far committed to end subsidies to gas production and consumption by 2025. Some gas sector associations are proposing mid-term low-gas penetration targets; e.g. to cover for 11% of EU gas consumption by 2030. In addition, more and more individual companies are announcing their own specific targets.

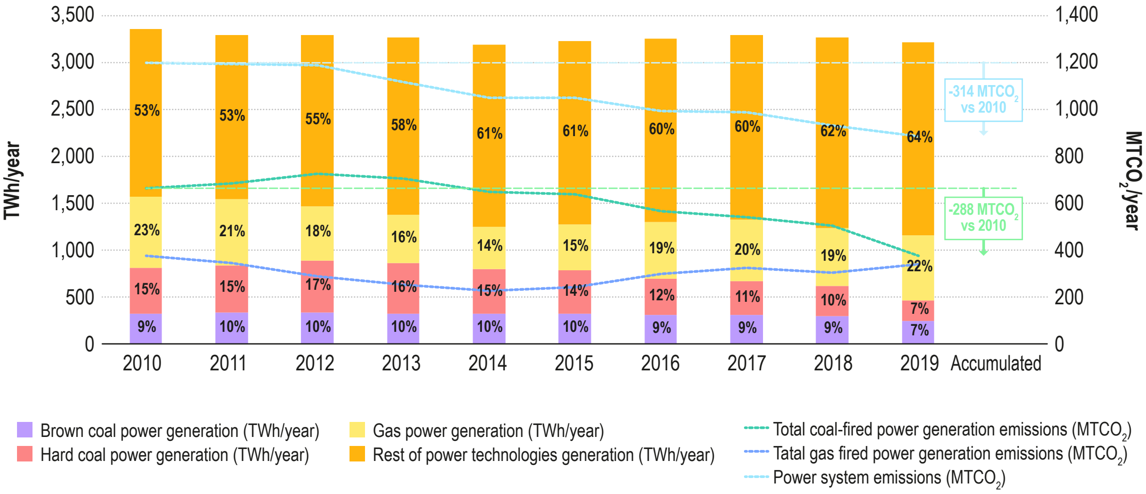
81 See IPPC estimations. Figures are contingent to the specificities of the raw input fuel and their extraction processes, as well as on the efficiencies of the transportation chain and power plants.

82 See also JRC estimations on the subject. The JRC study also models the potential price impact of coal phase outs on power marginal prices, which can total up to 10 euros/MWh in some MSs.

83 ENTSOs TYNDP scenarios foresee that RES-E will keep eroding both coal and gas shares to achieve the EU power sector carbon neutrality target in 2040. CCGT's will cover for less than 15% of power generation by then.

117 Figure 9 shows the evolution of the carbon intensity of EU power generation in the last decade, making use of the EU Environmental Energy Agency (EEA) estimates and focusing on the movement of coal and gas generation shares. It shows how the decline in coal-fired generation throughout recent years, paralleled by a rise in CCGT's and crucially RES-E production, has led to sizeable emission reductions[84].

Figure 9: Evolution of coal and gas net power generation shares in EU and the UK and effects on total power system carbon emissions – 2010–2019 – TWh/year and $MtCO_2$



Source: ACER based on Eurostat, UN Intergovernmental Panel on Climate Change and EEA data.

Note: ENTSO-E early estimates account to 24% of gas and 12% of coal share in EU's power generation mix in 2020. EU's coal installed capacity is 130 GW and CCGTs capacity accounts for around 175 GW. The emission intensity per MS is analysed in Figure v in Annex 1.

118 Estimating the exact contribution of coal-to-gas switching to the power system's decarbonisation is difficult. While the expansion of RES-E can be modelled against a counterfactual scenario where all renewables displace fossil technologies, coal and gas replace each other in accordance to their variable profitability margins, whilst both can be displaced by RES-E. Rough estimates done by solely looking at the years when coal-power generation declines were paralleled by net increases in gas-fired power production show that one fourth of the total power system emission' drops achieved throughout the 2015-2019 period could be assigned to coal to gas shifts. Those estimates need to be taken with caution, as they are dependent on the period and approach considered[85].

119 At any rate, the Paris Agreement considers coal plant phase-outs as the single most effective measure to reduce global carbon emissions. Hence, it favours that countries include in their climate actions plans ambitions for them to be in place in full by 2030. Almost all MSs as well as EnC CPs like Ukraine have committed to phase out coal plants over the coming years. However, some of the countries hosting a larger coal presence have pledged to achieve this target only by 2038 at the latest[86].

120 So far, the extent of the coal to gas shifts in power generation has been diverse in magnitude across MSs. Greece, Spain, Latvia and Portugal show the largest switches across the last two decades, but the Netherlands, Italy and the UK had started a significant transition before. Czech Republic and Poland account for the highest relative coal shares today (40% and 74% of power generation capacity respectively[87]). Figure iv in Annex 1 shows the detailed values per MS.

84 Moreover, in accordance to EEA data, EU power generation emissions have nearly halved between 2019 and 1990. The reduction has occurred in the context of lower nuclear electricity production since 2004.

85 A more precise analysis should contrast the coal and gas power-generators' bids every day, to model the actual coal-fired power production that would had entered the power pool in the absence of a rising presence of gas. Those analyses haven't been possible in this MMR edition.

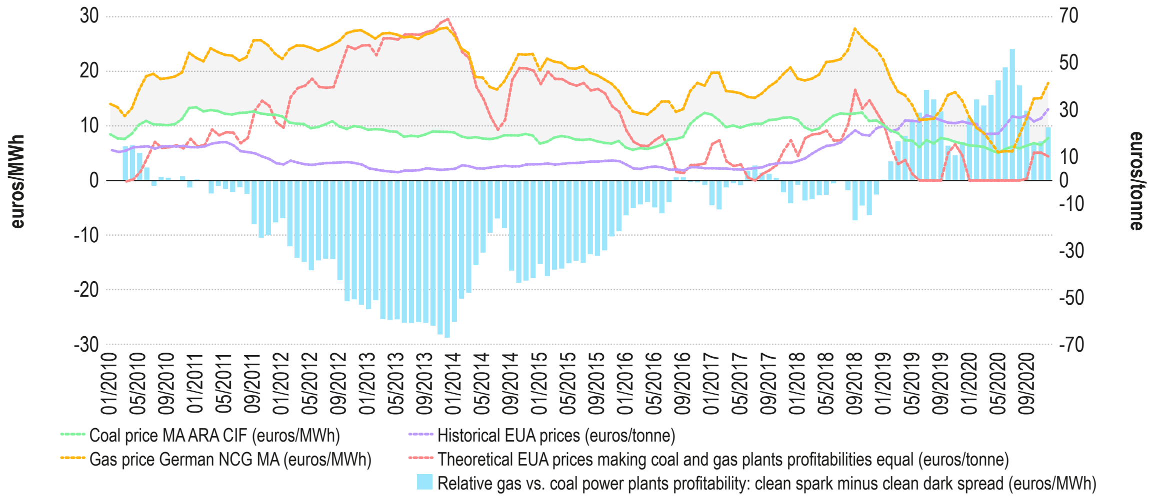
86 Seven MSs have not committed to phase-out coal by 2030: Bulgaria, Croatia, Czechia, Germany, Poland, Romania and Slovenia. As such, 52 GWs of coal-fired capacity is expected to be operational after 2030, 90% of it in Czechia, Germany and Poland. The EU Just Transition fund will mobilise up to 40 billion euros in subsidies to counterbalance the economic impacts at the regions and for the utilities operating the coal plants.

87 In Poland coal has still also a relevant share in the heating sector – i.e. up to 50%. Nonetheless, coal-fired power generation is expected to halve by 2030, as CCGTs capacity will almost triple by then.

121 Up until now, the drivers backing the EU's coal to gas shifts have been environmental – i.e. emission' limits and air quality regulations[88] – technological and decisively economic, as both technologies tend to compete to set the marginal prices in most MSs power markets.

122 The introduction of carbon emissions pricing in the framework of the EU's Emission Trading System[89] has been key in shaping coal and gas-fired power generation profitability. The emission costs determine, together with the prices of the raw input fuels and the electricity value, the margins of fossil-fuelled power plants. Figure 10 offers an overview of the gas vs coal profitability margins in view of historical EU emission allowance prices (EUAs). The rising cost of EUAs together with the dropping price of gas made gas power generation margins higher than coal ones through 2020, further assisting the switches[90].

Figure 10: EUAs price evolution and month-ahead clean spark and clean dark spreads at German coal and gas power plants – 2016–2020



Source: Reuters and ICIS Heren.

Note: The spark and dark clean spreads measure respectively the gross margin of gas and coal-fired power plants from selling electricity, deducing the input fuel and the carbon emission allowances paid to produce this electricity. Gas and coal power conversion efficiencies considered are 50% and 39% respectively.

123 Figure 10 also infers what level of EUAs pricing – assuming electricity, gas and coal price factors remain equal – would have made gas-fired power generation as economic as coal-fired one. Fixing those factors is a theoretical exercise, as the three elements are highly correlated. Emission prices over 20 euros/tonne since 2019 have sufficed to make gas margins more profitable than coal, while during the first half of the decade coal generation was more cost-effective, given the then higher gas prices and insufficiently expensive EUAs.

124 Finally, the EU efforts and contributions of shifting coal to gas need to be put in perspective at a global level. The EU accounts for 7% of the global power coal-fired emissions, with India (11%) and especially China (45%) leading in absolute terms, despite both – and many other – countries are also introducing more stringent emission reductions[91]. The further spreading of the EU's regulatory approaches, technology transfers and the use of international carbon credits (the latter two are lines of action backed by the Paris Agreement) in addition to initiatives such as carbon taxations should allow the EU to contribute to abate emissions world-wide.

88 E.g. Directive on industrial emissions integrated pollution prevention and control. Besides, the CEP introduced emission limits of 550 g of CO_2/kWh el for new power technologies to receive capacity payments since 2019. The Agency has recently issued a decision on the subject.

89 The EU Emission Trading System obliges power generators of more than 20 MW to purchase all their emission allowances since 2013, although, as an exception, 10 countries have the option to grant free allocation to power generators to help financing projects aimed at the decarbonisation of their systems. Brexit has meant that the UK will no longer be part of the EU ETS.

90 EUAs spot prices continued to climb in 2020 and reached in March 2021 a high-ever price of more than 40 euros/tonne that have maintained since. The rise has been led by the introduction of the Market Stability Reserve from 2019, adjusting downwards the number of auctioned allowances. Besides, the increasing hedging activity of utilities and financial players has supported EUAs forward prices, and subsequently spot ones; the market is anticipating a higher mid-term price environment resulting from forthcoming regulatory reforms.

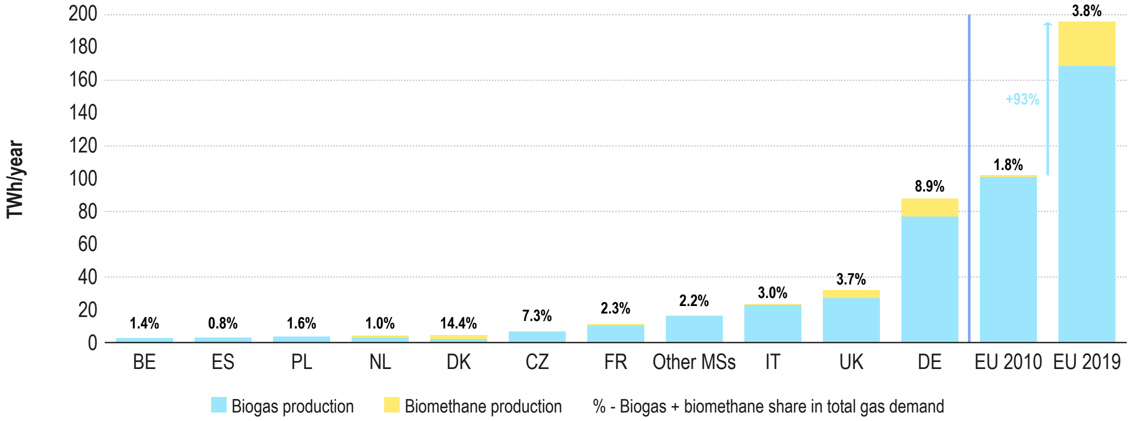
91 In accordance to IEA data, the EU power generation carbon intensity reached 270 gCO_2/kWh in 2018, while accounted 400 gCO_2/kWh in the United States, 600 gCO_2/kWh in China and over 700 gCO_2/kWh in India and Australia. Global power sector emissions declined by 3.3% in 2020 due to COVID-19 crisis, the largest fall on record. Coal covered 2% less percentage points YoY, but is still in the lead with a global share of 35%. However, global coal demand is set to rise 4.5% YoY in 2021, with 80% of that growth in Asia.

3.2 Carbon neutral gases current production and prospects

Current status

125 The presence of low-carbon gases among MSs is modest, even if Figure 11 shows how their volume has doubled in the last 10 years. Production efforts have been mainly focused on biogas and biomethane, which accounted for 15% of EU gas domestic production in 2019 (and 3.8% of consumption), making the area the world's leading producer of renewable gases.

Figure 11: Biogas and biomethane production in selected leading MSs in 2019 and for the whole EU – 2010–2019 – TWh/year and % of total gas demand relative to production



Source: ACER calculation based on Eurostat and EBA.

126 Most biogas continues to be produced and consumed close to the production site, either for heating or electricity generation, or for combined heat and power cogeneration (CHP). Germany, the UK and Italy are the frontrunners in absolute terms, while the share of biogas in final gas demand varies between MSs. Reaching 15% in Sweden and Denmark and in some 10% Germany in 2019. Section 3.3 offers further insight into the predominant biogas feedstock across MSs.

127 Upgraded biomethane volumes injected into the network account for 13% of biogas production on average across the EU, having risen 15% in 2020. The modest injections, which chiefly occur at the distribution level, are due to higher production costs, gas quality and other technical constraints. The notable exceptions are Denmark and the Netherlands, where biomethane injections exceed 50% and 30% of biogas production, respectively. France is leading in terms of setting up new biomethane facilities, whereas Germany is the second largest (world) producer after the US, with more than 10 TWh in 2019.

128 EU hydrogen production is rather moderate relative to future expectations with an estimated 340 TWh/year, less than 2% of the EU total energy intake. Most hydrogen originates from oil refinery by-products followed by steam methane reforming without CCS, and as such, significant carbon emissions are associated with its production[92]. Production chiefly takes place close to demand sites. There is still no large-scale transport infrastructure apart from a number of non-regulated distribution networks at industrial clusters in Germany, Benelux, France and the UK, the countries where hydrogen consumption is highest.

129 Electrolysers produce less than 3% of the EU's commercial hydrogen volumes, sourced with a minor input of RES-E. Germany, France and the Netherlands host most of the plants in operation. Although the total installed capacity has doubled in the course of the last four years, power to hydrogen plants totals less than 1 GW, with the largest facilities in the range of 10 MW. However; the construction of more than 3 GWs of new plants is anticipated in 2021.

92 Hydrogen production associated carbon emissions is estimated to total up to 70 to Mt CO_2 annually in the EU. The production of one grey hydrogen tonne is assessed to release 10 tonnes of carbon dioxide.

Mid-term prospects

130 Notwithstanding the modest volumes of low-carbon gas production to date, very ambitious penetration targets are foreseen for the next decades. In fact, a large quantity of mid-term plans and investment commitments were approved in 2020:

- From the policy makers' perspective, the low-carbon gas shift supports a sustainable sector that will help to assist the post-COVID-19 economic recovery by investing in high-value technologies while promoting the EU's domestic energy production[93].
- The gas industry and several energy-intensive consumers perceive overall the transition as a strategic business opportunity to uphold their relevance and diversify their revenue streams[94]. This is decisively the case for prevailing gas infrastructure owners.

131 In the area of biogas, the sector associations forecast that the EU's production will have doubled by the end of this decade and will have quadrupled by 2050, covering 25% of gaseous demand by then[95]. The ENTSOs' scenarios estimate this share between 10% and 30% by mid-century. They both foresee import potential from neighbouring countries such as Russia and Ukraine and some modest role of synthetic gas obtained from coal and biomass thermal gasification technologies.

132 Hydrogen Europe projects that hydrogen, in its diverse forms, will total 13% of the EU's gaseous energy consumption by 2030[96]. This implies that hydrogen would scale up much faster than RES-E has done in the last decades. The most favourable among the ENTSOs' scenarios estimates that hydrogen could become an as important energy carrier as methane by 2050. As for its final consumption, refineries and ammonia production would account for most of the demand in the near-term, where other industrial sectors that are hard to electrify, such as steel, iron and cement, but also power generation, space heating and road transport, would gradually gain weight.

133 Various other mid- and long-term scenarios have been projected, making use of different assumptions leading to quite diverse results[97]. These attract controversy, chiefly in terms of the evolution of costs and with regard to the scale of investments in power generation[98].

134 In any case, it is clear that hydrogen has become a central element in the plans to decarbonise the gas sector. The EC hydrogen strategy has specifically set as a clear long-term objective to endorse green hydrogen, while blue hydrogen would have a transitional short-to-mid-run role to scale up production and avoid grey hydrogen's associated emissions.

135 The EC strategy aims for at least 6 GW of electrolysers in the EU by 2024. These first-wave facilities are intended to get sourced, for the most part, from the electric grid, serving industrial clusters and replacing their current grey hydrogen supply. But the strategy further ambitions to install 34 GWs more, plus another 40 GWs in Europe's neighbourhood with export to the EU, by 2030. For the latter, agreements with North-Africa and Ukraine are being explored. These second-wave capacities would be chiefly fed by RES-E and gradually reach a broader group of clients and networks. If operated at an average load factor of 40%, their produced hydrogen could total more than 6% of the EU 2020 gas consumption by 2030[99].

93 The EC hydrogen strategy foresees investments of up to EUR 470 billion in RES generation, network adaptation and expansion of electrolysers' capacity by 2050 (i.e. 500 GW installed by then). The EU Next Generation Recovery plan as well as other national funds will mobilise relevant parts of these massive investments. Green bonds exempted of taxes are also gaining in relevance.

94 An European Clean Hydrogen Alliance was announced in March 2020 to bring together the industry stakeholders to accelerate the transition. Interestingly, the coexistence of both blue and green hydrogen as well as biogas, favours that actors with different interests support the transition.

95 See European Biogas Association statistical report.

96 See Hydrogen Europe 2030 Blueprint.

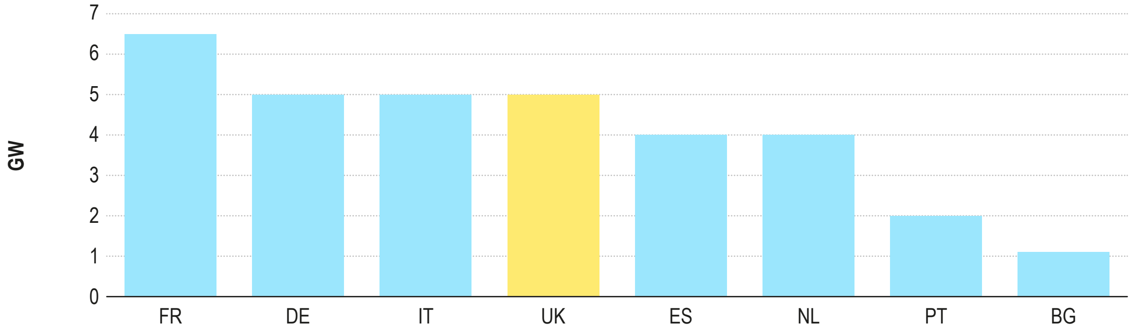
97 The JRC offers a comparison of hydrogen penetration scenarios of the EC and other research institutions.

98 Operating power-to-gas facilities at a scale large enough to replace conventional natural gas would require doubling today's EU installed power generation capacity over the next 30 years.

99 The load factors of the electrolysers would vary from up to 80% of those directly connected to the electric grid to lowest load factors of those fed by photovoltaic. See footnote 96 report for further considerations.

136 The commitments included in MSs' National Energy and Climate Plans (NECPs) as well as in the national proposals about how to invest the EU Recovery Funds back the hydrogen penetration targets mentioned above. Figure 12 offers an overview of the power to hydrogen capacity scheduled at front-running MSs by 2030. More and more projects are announced across the board, with the largest RES-E fed promotions accounting for hundreds of MWs[100].

Figure 12: Mid-term planned electrolysers' capacity by MS and UK at NECPs* – GW – 2030



Source: ACER calculation based on NECPs. The UK commitment includes blue hydrogen with CCS.

137 With regard to the role of blue hydrogen, MSs have expressed divergent views so far. The UK and the Netherlands have articulated the most ambitious and firm plans while some other MSs such as Germany consider them in more limited and transitional. Reasons include its arguably lesser sustainability, but also the fact that carbon storage attracts some public acceptance controversy, with onshore CCS sites having a lower approval rate than offshore ones[101]. In turn, global oil and gas producers are more vocally backing blue hydrogen technologies, which would better enable linking their ample fossil resources to a massive carbon-neutral output. Hydrogen transformation into easier-to-transport ammonia would facilitate their long-distance exports.

Energy Community

138 EnC CPs also have the ambition to adapt to the low-carbon gases transition. In May 2020, the EnC Secretariat launched a study to assess the potential for hydrogen in its contracting parties. The study aims at examining the readiness to produce and export hydrogen, while also identifying CPs potential demand per sector[102].

139 The analysis concludes that Ukraine has a high potential for exporting hydrogen through its current gas pipeline system. In fact, Ukraine published its own Hydrogen Roadmap in March 2021, which seeks to install 10 GW of electrolyser capacity by 2030. Most projects are aimed to get sourced by wind power production. The Ukrainian Roadmap is related to the EC hydrogen strategy, which seeks to develop strategic partnership with neighbouring MSs that could use Ukrainian hydrogen exports.

140 The EnC Secretariat analysis identified as well that Georgian, Ukrainian and Moldovan gas networks have capacity for admixing hydrogen. An incentive for using hydrogen in Serbia, Bosnia and Herzegovina and Kosovo* can possibly contribute to a more flexible management of the electric grid services, chiefly if RES-E get further expanded.

100 Hydrogen Europe maintains a registry of the ongoing and announced projects.

101 The theoretical potential for carbon storage across the EU and the UK accounts for 120 Gt CO_2, equivalent to more than thirty years of the total EU power system carbon output. In accordance to IEA data, more than 20 new carbon capture projects have been announced for commissioning in the 2020s, not only in UK but also other MSs surrounding the North Sea. Sweden and Norway have particularly large offshore carbon suitable offshore storage capabilities. Carbon transport and storage costs are assessed between 10 to 30 euros/tonne, offshore sites being the costliest.

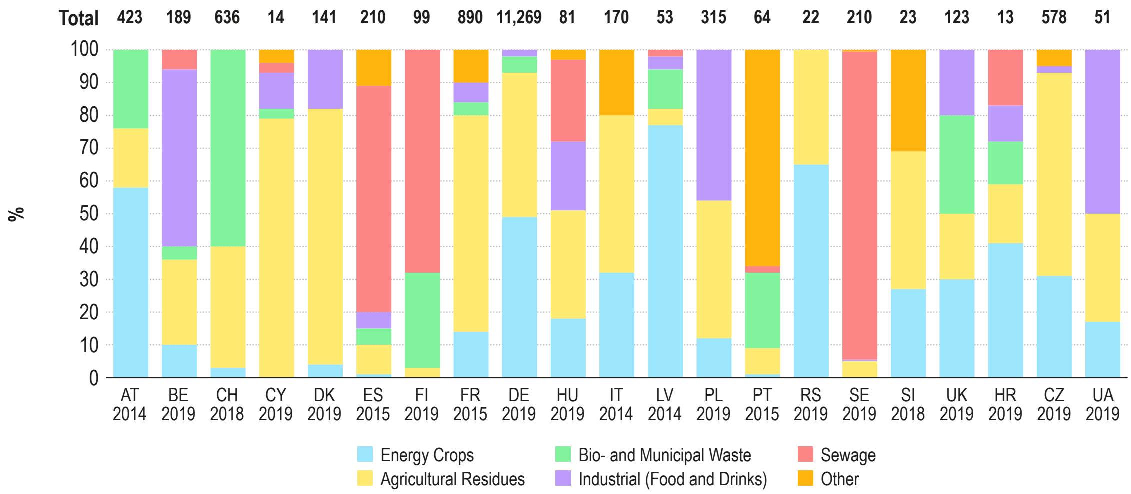
102 The results are presented in accordance to the final sector demand potential: industry, power generation and space heating, as well as revised the readiness to transport and importantly export hydrogen.

3.3 Feedstock availability

141 The availability of feedstock resources, as well as their cost relative to their energy potential, have been decisive in driving the distinct low-carbon gases adoption so far. In the years to come, their explicit emission savings potential is likely to gain further in significance.

142 Biogas has different production pathways that involve varied feedstock inputs. On average across the EU, the prevalent biogas feedstock originates from the agricultural sector, either in the form of energy crops or agrarian residues. Even so, farms manure and biowaste from households or industrials have a large penetration in certain MSs. Figure 13 shows the biogas feedstock' distribution per MS, together with the total number of biogas operational plants. Those total some 19,000 – plus 730 for biomethane – with the largest plant's capacity in the range of 50 MW (the average in less than 1 MW[103]).

Figure 13: Breakdown of feedstock resources for biogas production across MSs and number of biogas plants – 2019 and EU aggregates – 2015–2019



Source: ACER based on EBA.

Note: Regardless of the feedstock, almost all EU biogas is obtained via anaerobic fermentation technologies, with syngas produced from thermochemical conversion having a much lower presence.

143 Even if still dominant, the use of agrarian resources as feedstock of biogas is being constrained following more stringent environmental regulations that prohibit competition with food production or land use changes. As such, the emerging trend is to move away from energy crops towards agrarian residues, biowaste and farms manure[104]. In fact, no new plants have been established to solely operate using energy crops since 2017.

144 The capability of the various feedstocks to abate emissions is an increasingly relevant factor when deciding what biogas resources to uphold. The RED directive has set standardised methods to asses that contribution, with farm manure showing the highest competence[105]. The assessment makes use of the features of the raw materials in terms of the carbon that they capture and/or the fugitive emissions that they would have emitted if not processed into biogas. This is in addition to considering their production, processing, transport-distance and final use technicalities.

145 Indeed, the fugitive methane emissions associated to biogas suitable residues are a relevant element, given their large-scale potential for decarbonisation. In its annual greenhouse gas inventory, the EEA assesses that more than half of the methane emissions related to human activity originate from agriculture and farms, followed by household and industrial waste. A lot of them could produce biogas. A widespread capturing and processing of all those biodegradable resources for its conversion into biogas would deliver critical decarbonisation benefits.

103 A map of the locations and size of the plants is made available by EBA and GIE.

104 For example, Denmark has the objective of treating 50% of the country livestock manure in biogas plants in this decade.

105 See Renewables Directive, Part A Annex VI.

146 To that end, the recent EC Methane Strategy heavily endorses biogas capturing, not only for lessening the direct emissions that would otherwise escape into the atmosphere, but also to displace the consumption of conventional fuels[106]. Besides, the fermentation processes at biogas facilities produce residues that can be used as fertilizers, reducing the energy demand to produce those.

147 In the case of green hydrogen, the feedstock resource relates to the size and ease of access to RES-E generation, meaning there is benefit in placing the transformation plants at locations where water supplies, gas and electricity network, as well as if possible suitable UGSs and demand sites are concurrently easily accessible. Further coordination in planning gas and electricity networks should facilitate determining the most suitable locations. In this respect, there should be room for locational signals to promote the places where these plants contribute the most to the energy system[107].

148 In view of the twofold objective of decarbonizing the EU power sector by 2040 and expanding the electrification of the energy system, extremely ambitious plans to develop RES-E generation have been announced[108]. As an illustration, the recent EC offshore wind strategy foresees 60 GW and 300 GW of wind offshore energy by 2030 and 2050, respectively, skyrocketing from the 12 GWs installed today. All extra RES-E should assist the expanding electrification of vehicles and heating of households, as well as resource green hydrogen plants[109].

149 As a final point, the distinct availability of feedstock resources is leading MSs to support different decarbonised gas technologies. For example, in Germany and Denmark, biogas production is intended to keep growing[110], while Spanish, Italian and Portuguese NECPs chiefly back hydrogen production from cost-competitive RES-E photovoltaic, even if also from wind sources. France for example also considers nuclear power as relevant input for hydrogen production.

3.4 Decarbonised gas in the transport sector

150 Sectors outside the direct energy supply also need to contribute to achieving the EU decarbonisation targets. This is particularly the case in the transport sector, which is the second largest emissions contributor after energy supply[111]. While electric vehicles (EVs) will have the highest impact, there is also potential for gas to contribute to the sector decarbonisation via the utilisation of compressed natural gas (CNG) – which can also have a low carbon origin (bio-CNG) – and LNG.

151 The Green New Deal sets a 90% reduction of emissions in the transport sector by 2050. However, the EC Sustainable and Smart Mobility Strategy112 has identified that the use of low and zero carbon emission vehicles, which shall make this target possible, is still too low. The Mobility Strategy aims to address by developing incentives, the removal of subsidies for fossil fuels and by implementing a fair and efficient pricing for all modes of transport.

152 The targets will not be achieved by a single technology nor a single transport sector. A range of options will be required to reduce emissions. Figure 14 shows the share of emissions of each transport sector and complementarily provides a breakdown of the largest emitters in the road sector per vehicle type. It shows that while light-duty vehicles (LDVs) account for the vast majority of all road vehicles (87%)[113], heavy duty-vehicles (HDVs) account for a much higher relative level of emissions.

106 To promote the reduction of methane leakages in agriculture, the EC will develop an inventory of best practices, available technologies and innovative technologies in 2021 as part of the Methane Strategy.

107 In accordance to distinct estimates (see example), natural gas transport is from 3 to 10 times cheaper than electricity transport for energy unit and km.

108 In accordance to ENTSO's TYNDP, most electrification leaning appraisals' power production could rise by 30% in the EU by 2040 and 50% by 2050 (see footnote 83).

109 Accomplishing the mid-term targets set for EVs deployment and green hydrogen production would entail an extra 6-7% electricity supply for each by 2030 in accordance to IEA estimations. As such, there is likely to be competition between a direct use of RES-E or for using the RES-E input to source power to gas facilities.

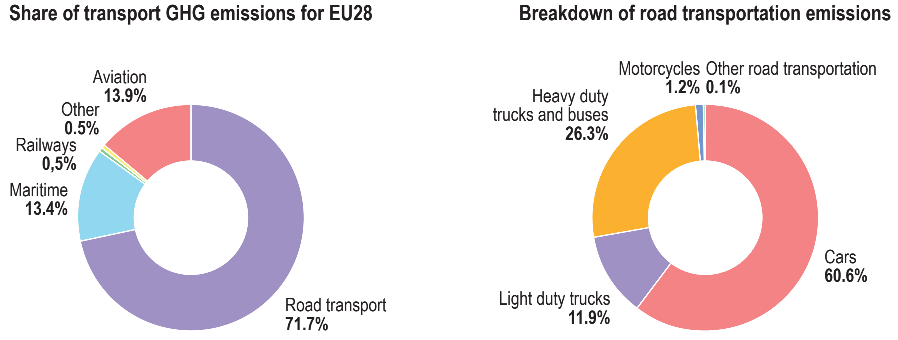
110 Power-to-gas will play a very relevant role there, as the ample wind energy potential is aimed to feed hydrogen industrial consumption points. German NECP, for example, sets the target for a combined support of nine billion euros to develop up to 10 GWs of hydrogen by 2040.

111 The transport sector is responsible of some one quarter of total EU carbon emissions, while road transport accounts for three times more than aviation and shipping segments combined. In contrast to other sectors, emissions from transport have climbed across the EU in the last decades. See EEA assessments on the subject.

112 See EC Mobility strategy.

113 See European Automobile Association 2021 report.

Figure 14: Comparison of transport sector emissions and road sector emissions split – 2019



Source: EC JRC.

Mid-term prospects

153 In accordance to most estimates, EVs will play a dominant role to decarbonise the LDVs fleet, with 30 million EVs targeted by 2030, a 30% share[114]. Natural gas could also play its part, with some projections envisaging that 10% of EU LDVs sales will be natural gas vehicles (NGVs) in 2030. However, the penetration of NGVs remains limited today. They account for less than 3% of the EU's LDV fleet, representing around 5 bcm of annual consumption. The highest NGVs presence is in Italy and Bulgaria.

154 The contribution of gas could be higher in HDVs, because they enable to drive larger distances between refuelling operations than EVs and also because the weight of the fuel deposit is lower than that of electric batteries. Today, 97.8% of all trucks in the EU run on diesel. This opens up an opportunity for gas either in compressed or liquefied form to deliver substantial emission savings. According to some estimates a target of a 30% share of CNG in buses and trucks, where electricity is still less of an option, could be achieved by 2030. According to RED estimates CNG vehicles emit 25% less carbon than diesel. But carbon reductions can reach more than 90% if low carbon gases are considered. In addition, the fuel costs for gas are currently assessed as 30% to 40% cheaper than for diesel on a per km basis, benefitting also from lower taxes. LNG is also foreseen to increase its penetration in the EU's, chiefly in the longest-range HDVs fleet. In accordance to NGVAs Europe data[115], there are already about 11.000 LNG-powered trucks on European roads today. The number is called for keep rising hand on hand with network refuelling extension and some incentives to vehicles purchase or lessened toll fees.

155 To enable fuel switching, the Mobility Strategy and the Directive for the deployment of alternative fuels require that MSs provide a minimum infrastructure for electricity, hydrogen and natural gas. The location of the existing CNG stations are made available by the EU NGV association. Italy leads with more than one thousand stations, followed by Germany and the Netherlands. A revision of the Directive is expected in 2021 in order to achieve greater harmonisation of efforts and a level playing field across the various fuels.

3.5 Production costs of renewable and low carbon gases

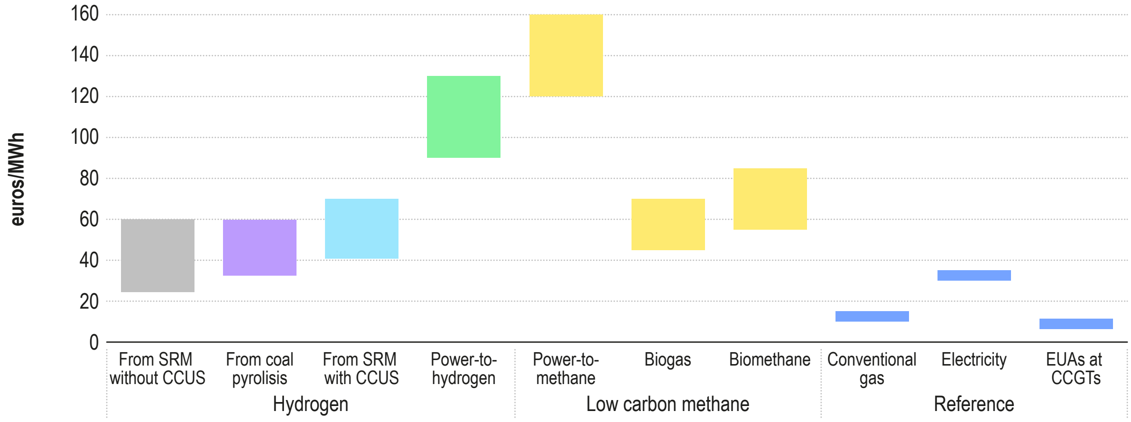
Current status

156 The competitiveness of the various carbon-neutral gas production technologies has been and will be decisive to determine their reach. Sound cost estimates are however difficult to make as they can be affected by local specificities, the plants' technicalities and the prices of raw materials. Figure 15 summarises the main technologies' cost ranges today using existing studies whilst benchmarking them against the price of conventional gas, electricity and EUA's cost to cover power production at gas-fired plants.

114 EVs are in the process of gaining traction among consumers as the variety of models available and range capability continues to increase. The redesign of electricity charging chains and also the expected reduction in battery cost is also called to increase the uptake of EVs.

115 The Natural & bio Gas Vehicle Association (NGVA Europe) promotes the use of natural and renewable gas as transport fuel. It maintains a map of fuelling stations. LNG stations total 300 in 2020, while there are some 4,000 CNG stations across the EU.

Figure 15: Illustrative overview of renewable and decarbonised gases technologies' production costs – 2020 euros/MWh



Source: ACER based on desk research of EC, OIES, IEA, Hydrogen Europe, IRENA and other studies.

Note: Conventional gas refers to the German NCG hub day-ahead price in 2020. Electricity price corresponds to German day-ahead baseload price in 2020. Emission price relate to the EUAs cost to back the generation of 1 MWh of electricity at a 50% efficiency CCGT in average in 2020.

157 Figure 15 shows how conventional natural gas sold at EU hubs averaged around 10 euros/MWh in 2020. This implies that the cost of the cheapest low-carbon gas option, biogas[116], was more than four times higher than of unabated gas. Green hydrogen accounted for at least three times the cost of electricity in energy equivalent terms.

158 The current price gaps should be put in perspective. Record low gas prices were observed in mid-2020 but have recuperated since then. Subsidies to production and consumption of gas are should terminate in this decade, which could lead to price increases. But, further than that, achieving the decarbonisation objectives to slow the climate crisis will inevitably lead to higher carbon prices and better energy efficiency in the years to come.

Mid-term prospects

159 The main factors that will drive the future price competitiveness of carbon-neutral gases relate to technological developments, economies of scale and the evolution of RES-E costs. The other crucial element in determining their affordability will be the price of carbon emissions under the EU ETS system.

160 Regarding the latter, various estimates suggest that a level of 80-100 euros per tonne of carbon dioxide would be needed to increase the attractiveness of most low-carbon gases. The EUAs' average price was around 25 euros per tonne in 2020, but a level of 40 euros per tonne has been maintained since early 2021[117]. Figure 10 presents the EUAs' price evolution in recent years, showing how they have roughly doubled since 2018.

161 In the field of biogas, production technologies are overall deemed more mature than that of other renewable gas technologies. Therefore, its potential cost reduction trajectory is seen as more limited[118]. However, the price premium of biogas against conventional natural gas is the smallest. Hence, the further scaling-up of equipment and cost reduction of the technology, together with more efficient feedstock gathering as well as, critically, the probable rise in EUAs prices can make the biogas business case more competitive in the years to come[119].

116 In turn, biogas production costs vary in accordance to the feedstock and the plant location, technology and scale. The use of waste at landfill sites followed by forestry resources are the cheapest options. See further considerations in the IEA biogas and biomethane outlook.

117 A carbon price of 100 euros/tonne would result in EUAs' costs of 35-40 euros/MWhel when generating power at CCGTs, depending of the technical features of the plants. This extra cost would close the gap between conventional gas and low-carbon gases.

118 Some studies refer that current cost could fall by 20–30% by 2050. A similar consideration is valid for grey and partially blue hydrogen production technologies.

119 See IEA estimates on the subject at footnote 116.

162 The ambition to reduce production costs is highest for green hydrogen. The fixed costs of the technology are fairly high, even if rather elastic. Therefore, scaling up equipment manufacturing should lead to significant cost reductions[120]. However, the costs of energy (RES-E for green hydrogen and natural gas for blue hydrogen) as well as the energy losses in the conversion process set some minimum variable costs for hydrogen production. In fact, notwithstanding that electrolysers' efficiencies can be moderately high in the range of 60%-70%, variable costs account for around 70% of the levelised costs.

163 A variety of studies[121] suggest that the price of green hydrogen could be reduced in the long term by 80% from a combination of cheaper electricity (estimates of 20 euros/MWh are cited, meaning half of current values), lower capex investment, increased efficiencies and longer operating hours. Some studies foresee that green hydrogen could be as price competitive as blue hydrogen by 2030, chiefly if sourced from the cheapest photovoltaic RES-E generation. Furthermore, power to gas facilities will with time factor into their business models their capability of flexibly shaping electricity demand, complementing electricity storage and transport or offering balancing services. There is also the possibility to monetise the excess of generated heat or oxygen, thereby increasing the overall efficiency of the process.

164 The charges for accessing the electricity and gas network are another critical consideration when studying the future economic feasibility of low-carbon gases. Therefore, the role of network tariffs should be subject to further analysis in light of the decarbonisation developments. Some existing natural gas networks could be retrofitted or repurposed efficiently to allow transition to low-carbon gases. A recent initiative by EU gas TSOs estimates that 75% of the future needed hydrogen network could be achieved by repurposing the exiting gas grid[122]. However, other studies foresee a much more limited scope of a future EU hydrogen network[123].

165 Significant investments will be required to promote hydrogen expansion, even if the ambition would be to prioritise networks' repurposing. A recent review of available studies done by ACER looked at the possibility of repurposing natural gas networks for pure hydrogen and came to the following conclusions:

- Investment costs for new hydrogen pipelines are 1.1 to 1.5 times higher than for natural gas.
- Investment costs to repurpose existing natural gas pipelines into pure hydrogen are three to five times lower than a new investment in pure hydrogen dedicated pipelines.
- Compressor stations for pure hydrogen are 1.4 to 1.8 times costlier than for natural gas and consume three times more power to maintain a similar energy flow.

166 These combined considerations imply that pure hydrogen transportation is two to three times costlier than natural gas transportation[124], representing approximately 10% of the final hydrogen commodity price. Section 5.4 further discusses the interoperability aspects of blending hydrogen injection into the current natural gas network.

167 Finally, the promotion of liquid and transparent organised carbon neutral gas markets can support optimising their pricing, by pulling together and enhancing competition between market players. However, these liquid hubs may still take some time to develop; local markets gathering clusters of consumption will probably emerge in initial phases, while larger cross-border transactions may take more time. As such, the low-carbon shift could be backed in the first years by bilateral contracting that distributes price and volume obligations and risks.

120 Electrolysers' fixed costs are assessed to have lessened by 60% across the last decade in accordance to IRENA and are currently in the range of 650 to 1.500 euros/kW, depending on the technology and scale. Alkaline technologies are the most cost-efficient, though proton exchange membrane technologies are closing the gap. The renewable Agency weights that a capacity factor of ten can reduce fixed costs by 50%, while a factor of one hundred lessen them by 75%. As earlier investors could face technical and scale competitive disadvantages compared to future investors, incentives are called for to ramp-up investments.

121 See also the IRENA study above or the Energy Transition group study. The IEA also estimates that green hydrogen production costs could fall by 30% in 2030.

122 Eleven TSOs published a Hydrogen Backbone Initiative in July 2020 (revised in April 20201), building hypothesis regarding cost of upgrading the gas network to accommodate hydrogen. Dedicated hydrogen pipes are expected to remain more limited, chiefly in the early phases, as demand will be met initially by close production or on site.

123 See for example this recent study from Agora Energiewende.

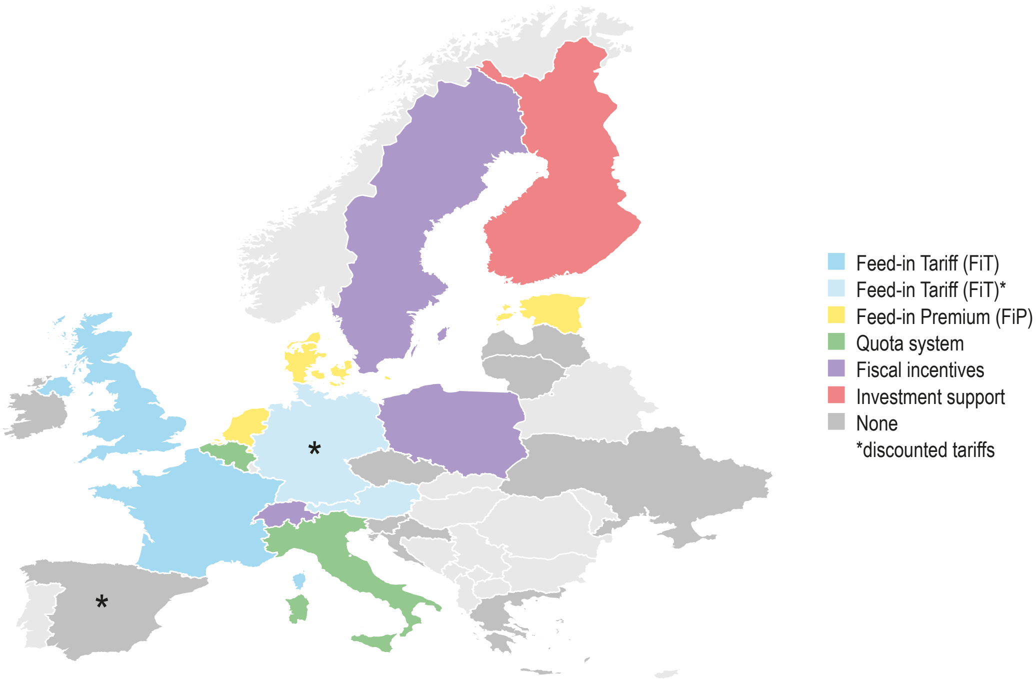
124 According to the Hydrogen Backbone initiative, the cost of transporting hydrogen ranges from 3 to 6 euros/MWh per 1000 km; see footnote 90. The estimates are caveated on the basis of the energy transmission technicalities and systems' geography. H_2 shipped overseas has to be liquefied or transported as ammonia or LOHCs. For distances under 1500 km, transporting H_2 as a gas by pipeline is likely to be the cheapest option.

3.6 Review of incentives granted to low carbon gases

168 As the production costs of low-carbon gas are considerably higher than the supply price of conventional natural gas, subsidies and ad-hoc financial support have been crucial to back their expansion so far. Incentives have been chiefly assigned to biogas and biomethane production, but the frame is expanding to include renewable hydrogen too. Without such incentives, the market for biomethane would more than likely not have developed.

169 The support measures can take different forms per jurisdiction, including favourable network access tariffs[125], ad-hoc fiscal frameworks, direct production subsidies and guarantees of origin, the latter effecting on their priority for production and carbon emission financing. Feed in tariffs are at present the most utilised support available across the EU. An overview of the distinct support policy types for biomethane is outlined in Figure 16.

Figure 16: Type of support schemes for biomethane production in MSs



Source: Renewable Gas Trade Europe[126].
*Note: *In Germany and Spain tariff discounts for the injection of biomethane into the network are granted.*

170 The administering of guarantees of origin attracts specific interest, in view of their possible further standardisation in the forthcoming RED revision, as discussed at the latest Madrid Forum[127]. It is envisaged that the RED review will provide a more comprehensive frame assisting to certify low-carbon gases across MSs, which would facilitate the recording of their penetration. This will be of particular relevance if the Directive also sets firm production targets. Next, a clearer frame should promote the transferring of the certified emission savings (either at supply or consumption level) potentially within the EU ETS.

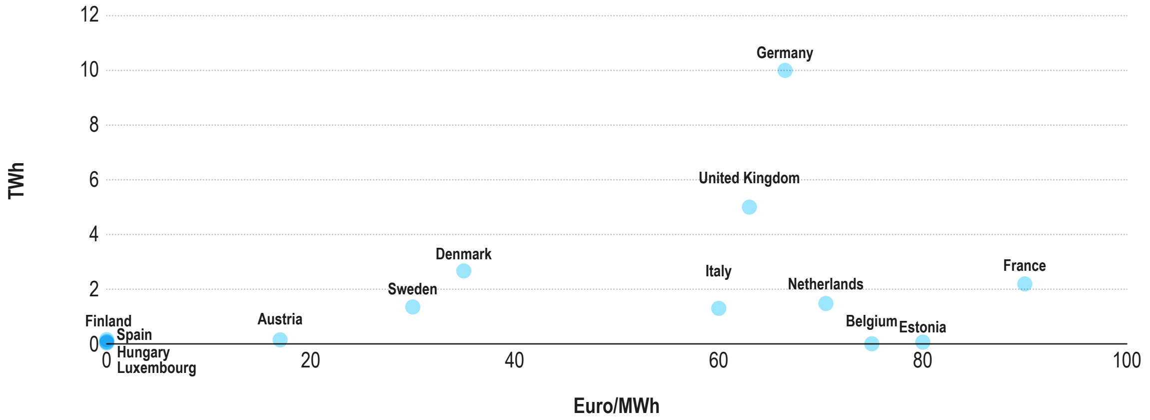
171 The effects of low-carbon gas incentives tend to be evident on their production. For example total production of biomethane is closely linked with the financial support schemes as shown in Figure 17. In some MSs, such as Germany and Italy, incentives have varied over time, moving production figures accordingly. For example in Germany, the expansion of biogas in recent years has been chiefly backed by guaranteed tariff levels and substrate bonus for energy crop, but aiming to explore a more cost-effective support mechanism, biogas plants have been invited to take part in RES auctions. The new German methodology on transmission tariffs proposes a 100% discount for biogas entry points to the network.

125 Such tariff reductions are not foreseen in the current Gas Transmission Tariffs Network Code and can therefore be incompliant. Nonetheless, tariffs' role may be subject to further analysis in the years to come in light of decarbonisation developments.

126 See REGATRACE study done for the EC in 2020 for mapping the state of play of renewable gases in Europe.

127 The viability of granting these guarantees has relied on the MS (Article 19 of RED). The revision of the RED Directive is envisaged for the second part of 2021. The EC has put it under consultation.

Figure 17: Biomethane support levels per MS vs production – TWh/year – euros/MWh



Source: Renewable Gas Trade Europe.

172 Subsidies for hydrogen production are not much developed. The RED Directive may further cover these, including an updated set of incentives to promote their use. Overall, MSs are backing research and development strategies before any larger scale uptake. Programmes mobilising hundreds of millions of euros are being announced to enable these achievements. Other elements in consideration are proposing conditions in the form of regulatory sand-boxes that preclude investors for paying access tariffs or VAT[128].

3.7 Methane leakages

173 To achieve the ambition of decarbonising the EU gas sector, the reduction of methane leakages is crucial. Methane is a more potent contributor to the greenhouse effect than carbon dioxide in the short term[129]. Therefore, undue flows can offset the benefits of natural gas relative to other fossil fuels in terms of the lower emissions generated by direct gas combustion.

174 The IEA estimates that natural gas has a lower emissions lifecycle (carbon equivalent) than coal as long as the total methane leakages are kept below 5.5% of the gas flown volume[130]. However; the exact percentage across the supply chain that serves the EU is hard to delimit, as gas outflows can amply vary per producer and supply route. Some studies estimate the average leakage for the EU in the range of 2-3%[131].

175 Methane leakages can originate at all the activities of the supply chain, from production and processing, to transmission, distribution, storage and end-use of gas[132]. The EEA estimates that, within the EU territory, transmission and distribution activities account for 70% of the total outflows. Marcogaz has specifically estimated in turn that LNG and UGS infrastructure operation accounts for less than 0.2% of EU's consumed gas.

176 All MSs and EnC CPs monitor and report their methane emissions following the guidance of the United Nations Intergovernmental Panel on Climate Change. In accordance to EEA data[133], the majority of the EU's methane emissions originate in the agriculture sector[134], while gas supply chain leakages totalled 6% in 2019. The exercise is quite challenging and a further common approach has become increasingly important to increase the exactness of the assessments[135].

128 For example in France the Jupiter project is an initiative to convert renewable power surplus into green hydrogen and storage.

129 The global warming potential of methane is assessed 25 times higher than for carbon dioxide across a 100-year period. Methane has a shorter atmospheric residence time than carbon dioxide, of around 10 years, but measured over a 20-year period, methane is up to 85 times more potent as a greenhouse gas.

130 See IEA assessment. Coal mining has also associated relevant methane emissions, chiefly at underground mines.

131 The Environmental Defense Fund tracks the aspect.

132 Some leakages are unintentional, e.g. permeable connectors, leaking valves, while others are intentional, due to the design of the equipment or processes, e.g. venting for security reasons. See Marcogaz report for the Madrid Forum on ways the EU gas industry can contribute to the reduction of methane leakages for a categorization of methane emissions by activity.

133 The EEA takes a responsible role in centralising the information at the EU level for the United Nations. See its analysis of GHG emission trends here. At the EnC, only Ukraine, sufficiently allocates leakages to specific parts of the gas chain.

134 In accordance to the EU methane strategy, 53% of anthropogenic methane emissions come from the agricultural sector, 26% from waste and 19% from energy.

135 As emissions are not straightforward to assess they can be either measured or modelled.

177 Within this ambition, the EC adopted an EU methane strategy[136] in October 2020. It aims to improve gas outflows' measurement and reporting, while also setting obligations to detect and repair leaks. Interestingly, the strategy proposes legislation to prohibit routine flaring and venting practices up to the point of production.

178 In 2019, 70% of the gas supply chain emissions within the EU territory were emitted by four countries: Germany, Italy, Romania and the UK[137]. They were mostly associated to gas transport and distribution in the former two, and to gas production in the latter two.

179 According to IEA data, the emission intensity of the EU's gas producers is significantly lower than in countries that export gas to the EU, with the exception of Norway, which is deemed a low-emission producer[138]. Although valuations are very challenging to trace and depend on several technical and transparency aspects, some estimates signal that relative leakages of selected external producers are at least three times higher. In this respect, an anticipated outcome of the EC methane strategy is to set methane supply index standards for imported gas, which could become progressively tougher over time.

180 The EU gas industry has undertaken activities to better report and mitigate the different types of methane leakages. These include using best practices and voluntary reduction targets[139]. Since 1990 to date, the leakages have been reduced by 59%, including minus 10% in the last 5 years. This has been achieved not only due to better detection and technical repair but also due to declining EU domestic production. Apart from environmental reasons, if the cost of the repair technologies to abate the leakages is competitive, there is an incentive to generate a profit[140]. The offsetting of the leakages through the ETS would further assist the financial case.

181 The technicalities of methane leakage assessments fall out of the scope of the MMR. However, it will be important to look at the market impact that a more stringent regulation on the subject may entail vis-a-vis external gas exporters in the years to come.

3.8 Regulatory framework for low carbon gases

182 The regulatory framework governing the gas decarbonisation shift must further clarify a number of interrelated aspects. The aspects will notably drive stakeholders' business models, and can be grouped into six areas:

1. Setting the technical rules that will define gas quality, blending and interoperability aspects.
2. Determining the activities and the conditions at which the market participants will be allowed to invest.
3. Determining the network access conditions for new gases; investment cost allocation and connection tariffs will be key elements for that.
4. Defining a framework to identify new network investments, be it brand-new or repurposed network, and to value the existing regulated asset base in case of transfer of assets.
5. Identifying and mobilizing ad-hoc support to the new technologies, at least in early phases.
6. Setting up market rules that promote and facilitate the access to liquid markets for producers and consumers.

183 Discussions about the best suitability of the regulatory framework are taking place in venues such as the Madrid Forum. Broad stakeholder dialogue is supported by the EC in view of the new Gas Fit for 55 Package expected by the end of 2021.

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136 See EC methane strategy as an integral part of the EU long-term climate strategy.

137 See footnote 133.

138 See IEA's methane tracker. Relevant steps are being taken in Norway to electrify the gas production platforms and limit their associated emissions.

139 In accordance to the previously referred study from Marcogaz, the median of reduction targets for methane emissions is 5.1 % per year, with differences per company and sector.

140 In accordance to some IEA and IFC estimates, it is technically viable to avoid around three quarters of the present-day global methane emissions, while 40-50% of them would be at a cost-efficient commercial value.

184 The all-embracing ambition is ensuring the decarbonisation shift in well-functioning, integrated and competitive markets, which shall ensure a level playing field between all energy carriers, in order to achieve decarbonisation at the lowest costs. It is also imperative to safeguard that the clean energy transition does not lead to market fragmentation.

185 ACER and CEER have recently proposed a number of recommendations in some of these areas, shared via related white papers[141]. The most relevant considerations related to market integration are:

- A clear separation between regulated network activities and market-based production activities; the main principles that govern the IGM today are to be maintained for low-carbon gases (i.e. unbundling, third party access, non-discrimination, monitoring and oversight)[142].
- Operate power-to-gas production facilities as a competitive activity. The plants' concessions would rather be assigned via competitive mechanisms, such as auctions. The role of TSOs/DSOs is to be limited to foster research in early phases, whereas possibly being prevented to owning or operating them. However, if no sufficient market interest is detected to invest in necessary facilities, a larger role could be assigned to TSOs under controlled conditions[143].
- Instruments other than tariffs should be used to subsidise the uptake of low-carbon gases. As a rule, separated hydrogen and methane RABs are favoured, while potential transfers of assets should be based on the regulated value at the time of transfer. The abolishment of intra-EU IP tariffs to promote decarbonisation is judged too challenging at this stage.
- The trading of low-carbon gas at organised markets need to be promoted, seeking for synergies with the current conventional gas trading platforms. Well-functioning guarantee of origins will be instrumental to promote trade. It is also important to authorise that low-carbon gas injected at the distribution level can be traded at the national virtual trading points. This could be achieved allowing a netting of the flows between the transmission and distribution levels.

186 Finally, and overall, a flexible and gradual non-regret regulatory approach is proposed. This is to better accommodate effective regulation during the early years of the market and grid development, acknowledging the uncertainties that will need to be faced. In doing that, consistent monitoring shall be promoted. Further considerations are addressed in the Recommendation section.

141 See ACER and CEER white paper, When and How to Regulate Hydrogen Networks.

142 Private business-to-business networks can be exempted from regulation, like closed distribution systems in a first phase.

143 Similar approaches have been considered for EVs recharging points and electricity storage. A hybrid possibility is that network operators become responsible for building and operating the facilities to serve the commercial petitions of those market participants having gained access capacity. If market interest is later detected they may have to divest.

Part II: The Internal Gas Market

4 Assessment of EU gas markets according to Gas Target Model metrics

187 The AGTM includes a set of indicators called market health and market participants' needs metrics that are respectively used to assess hubs' market structure and transactional activity. Their target thresholds and specific values are analysed in detail in this Chapter per hub.

4.1 Assessment of EU gas markets health and gas supply sourcing cost

188 In the context of the AGTM, the structural competition aspects of gas hubs are covered by the term market health. The related market health indicators measure the number and concentration of supply sources as well as the hubs' potential to meet demand using the supply infrastructure not controlled by the largest upstream supplier.

189 Better market health results – together with more liquid trading hubs – tend to result in lower gas supply sourcing costs[144]. As such, differences in supply costs can consequently reveal how effective the structure of a hub is in facilitating competition. Therefore, the market health assessment starts with gauging the sourcing costs prevalent at individual EU gas wholesale markets in 2020.

Gas sourcing cost

190 The cost of the gas that market participants purchase within a given MS can vary per company and period. This can be due to the contracts and hedging strategies employed by market participants as well as the gas supply origins. To estimate an average yearly theoretical gas supply price, ACER uses a methodology that considers three main types of gas sourcing costs based on the following: i) an explicit basket of hub products (in markets with sufficient forward products transactional activity), ii) declared cross-border imports and iii) domestic production prices[145].

191 For 2020, the assessment shows that the average gas supply sourcing costs fell by more than 4 euros/MWh in comparison to 2019 in the majority of MSs. Section 2.1.3. presents the key drivers behind the price reduction. The decrease in sourcing costs resulted in a substantially lower gas import bill for the EU, which according to EC estimates totalled 36.5 billion euros, a reduction of some 40% from 59.4 billion in 2019[146]. The magnitude of this saving, i.e. 23 billion euros last year, underlines the importance of a well-functioning EU gas market and the benefits it can bring to consumers.

192 Despite the 40% reduction, gas sourcing prices did not reduce in unison or to the same extent across all MSs. In addition, price differences also may have appeared between the distinct sourcing mechanisms within a country. The record price reductions of hub prompt products during the second and third quarters of 2020 were not matched by the actual supply price of those LTCs that still preserve in their formulas larger price-indexations either to oil or to mid and long curve hub products. At markets where the oil-price indexation of LTCs is still dominant, the sourcing cost gap against the TTF-based benchmark tended to be bigger[147].

144 Sourcing costs are also affected by factors other than upstream competition and liquidity. For example, lower prices are observed occasionally at MSs with prevailing oil-indexations under certain favourable conditions, even if they are not that competitive.

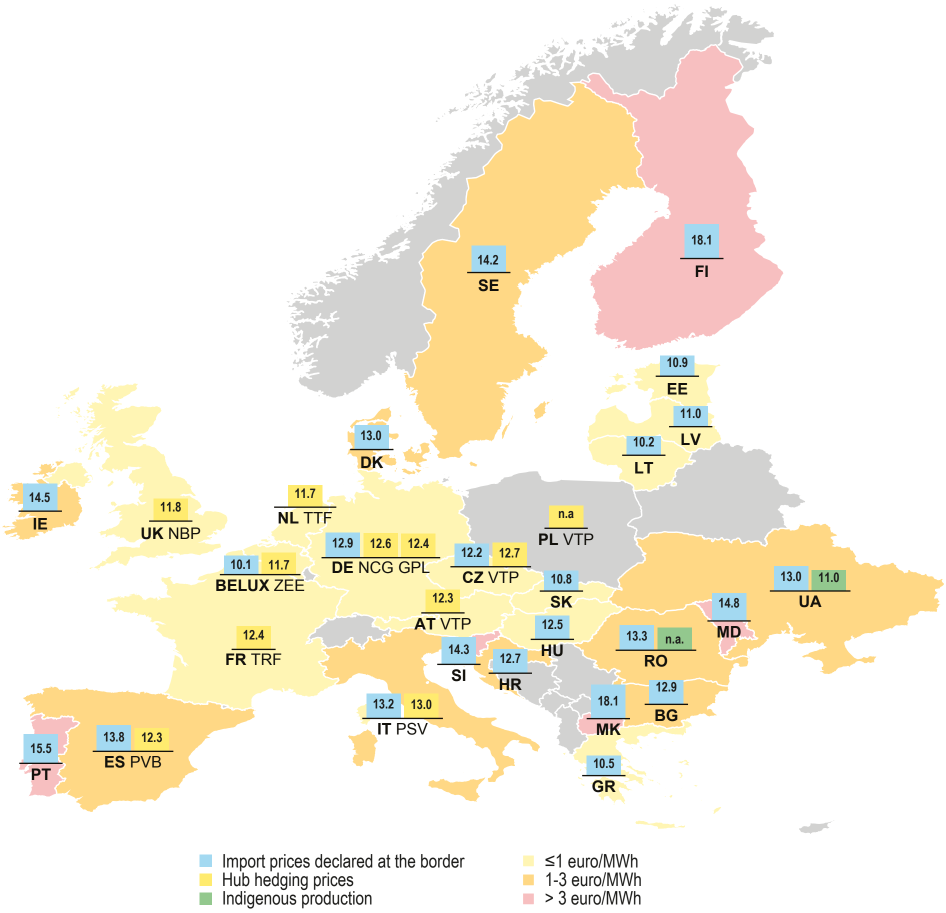
145 See MMR 2015, Annex 6 for details on the general methodology and specific data used for selected MSs.

146 See the EC quarterly gas market monitoring report for more details.

147 The prices of oil-indexed LTCs, as well as the prices of LTCs indexed to forward hub products tend to diverge more with the prices of prompt hub products in periods of hub prompt price volatility, as the former do not necessarily respond to short-term gas market developments. For similar reasons, the rapid hub prompt price recovery observed from autumn 2020, once LNG started to sway away into Asia, was sharper than of more stable LTCs prices. Nonetheless, the rise was not enough to fully counterbalance the yearly dominant picture.

193 Figure 18 shows the estimates for the distinct types of sourcing costs. Supply costs in most EnC CPs continue to be higher than in MSs, as a result of less favourable LTCs and lower upstream supply competition. The notable exception is Ukraine, also by far the largest gas market in the Energy Community, whose prices are becoming more correlated to EU hubs and where average price levels last year were in the same range as those in Italy and Spain.

Figure 18: 2020 estimated average suppliers' gas sourcing costs by MS and EnC CP and delta with TTF hub hedging prices – euros/MWh



Source: ACER calculation based on Eurostat Comext, ICIS and NRAs from both MSs and EnC CPs.
Note: Import prices for AT, NL, FR and PL could not be assessed.

194 Overall, gas prices in individual MSs are determined by a combination of factors. The level of competition and availability of suppliers' is key, but also crucial are the gas sourcing mechanisms, the degree of hub functionality and the transportation costs. All those factors result in a combination of marginal supply and market opportunity pricing that determine the final gas costs[148].

195 In addition, the exact role of each supply origin can vary per market and period. For example, the abundance of LNG available to EU gas markets during the first and second quarter of 2020 was a price disciplining factor in many markets as it enhanced supply options. However, this role faded in the autumn because of a reduction in volumes of LNG available to the EU market (see section 2.2.3 for further details).

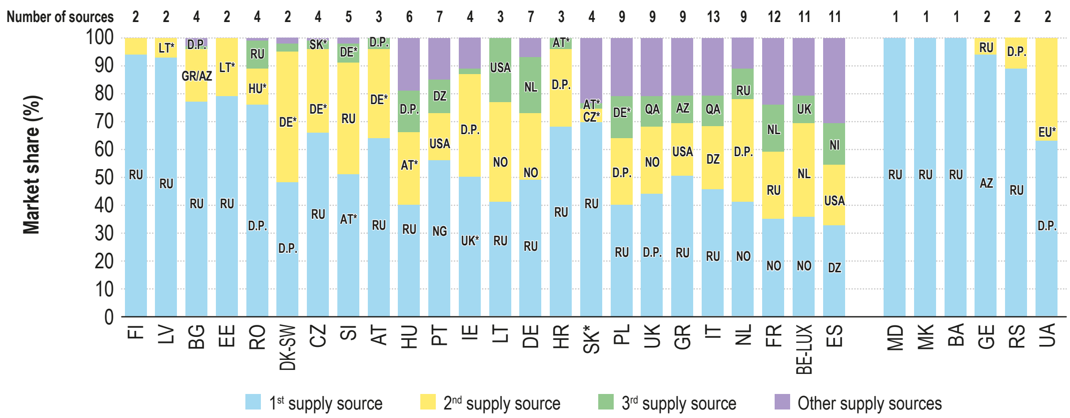
148 In practice, determining the exact impact of the various supply sources, including the most expensive one, on the price formation in individual gas markets is not straightforward as its importance may vary between gas hubs and time. For example, spot imports from Austria into Italy have traditionally played a role in price formation at the Italian PSV hub. However; with the Italian market increasingly relying on LNG and the start of deliveries from TAP this role has started to fade. Other examples per MS are provided in Chapter 3 of MMR 2019.

Number of sources of gas supply

196 As discussed in Section 2.1.2, gas supply rebalances resulted in some changes to the supply shares' of the geographical origins of gas in some MSs. Russian, Norwegian and Algerian pipeline supplies as well as liquefied gas imports maintained a dissimilar presence across the various EU regions, shaped by geographic and contractual reasons. In 2020, the supply share of LNG increased in most coastal MSs. This was due to the availability and lower cost of LNG across the year. Conversely, the supply share of gas produced in the EU decreased. Finally, the share of EU gas hubs – included in the assessment as an independent origin for those hubs with sufficiently high liquidity – has increased, as suppliers use hubs more and more as direct sourcing options. This has also been the case in Ukraine for some years.

197 Figure 19 examines the supply share in gas markets of MSs per country of gas supply origin for 2020. A more granular examination, for example at quarterly level, would reveal some differences due to the replacement between LNG and pipeline supplies discussed in Section 2.2.3.

Figure 19: Estimated number and diversity of supply sources in terms of the geographical origin of gas in selected MSs and EnC CPs – 2020 – % of actual volumes purchased[149]



Source: ACER calculation based on Eurostat Comext and EnC Secretariat data.

Note: D.P stands for domestic production (if over 0.5% of gas demand). The asterisk refers to MSs with liquid hubs where gas is declared to have been purchased. For the Danish-Swedish market, the share of domestic production also includes the Norwegian offshore fields that are part of the Danish upstream network. For Ukraine, the number of supply sources is likely higher than 2, based on the assumption that gas is sourced at various EU hubs, but could not be estimated more precisely. The values for EE, NL, AT, FR, DE and SK could not be estimated yet due to unavailability of Eurostat Comext data and correspond to 2019.

198 As of the end of 2019, no MS relies solely on a single gas supply source origin150. However, various EnC CPs continue to remain fully reliant on one external supplier. Markets with access to LNG tend to have the highest number of supply origins, the largest of which boast 10 or more distinct sources. Azerbaijan has been a new source origin for the EU since late 2020, after the first gas deliveries across TAP started to reach Bulgaria and Greece in Q4 2020 (see paragraph 74 for further details).

149 The metric looks at the geographical origin of the sourced gas and not at the number of distinct interconnection capabilities. Both figures may differ for selected MSs.

150 Until 2019 the Finnish market was fully supplied by Russian gas, but Balticconnector ended this dependence.

4.2 Assessment of EU gas hubs well-functionality degree

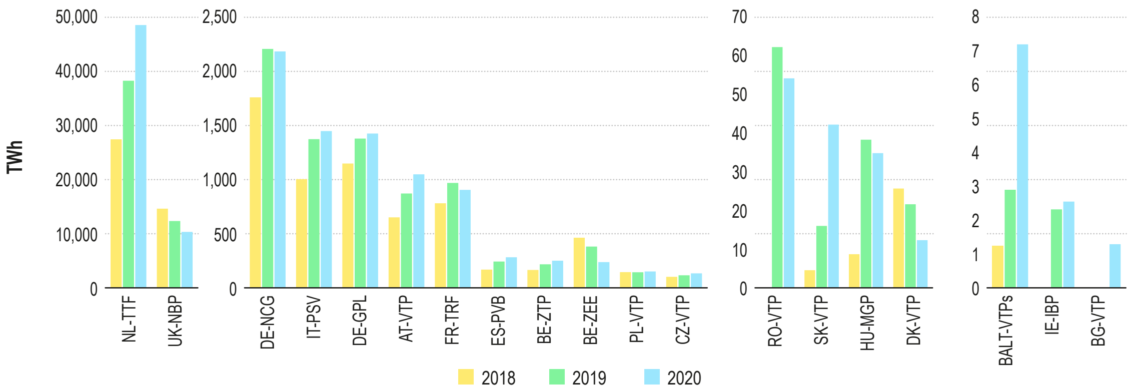
4.2.1 Overview of trading activity at EU gas hubs

199 Gas traded at the EU and UK hubs increased by 14% in 2020 compared to 2019, setting a new historical record. The volume of gas traded at transparently organised markets was more than 13 times higher than the combined gas consumption of the EU and the UK in 2020. The expansion of gas trading in the IGM has continued in recent years, with trading volumes increasing each year over the last decade, except in 2013 and 2017.

200 The increases were driven by harmonised structural changes to the IGM design and the related changes in long-term gas supply contracting practices. In 2020, the record price volatility caused by COVID-19 triggered further hedging activity from market participants.

201 In addition, the growing attractiveness of the TTF hub to hedge continental forward volumes as well as to increasingly arbitrage global LNG supplies has been crucial. The Dutch TTF hub was (as was the case in 2019) responsible for the vast majority of the EU growth YoY and now accounts for the majority of gas volumes traded in the EU. Aggregated traded volumes at other EU hubs also increased YoY, however analysis shows that such increases were not uniform across the EU hubs. Some EU hubs reported less trading activity than in the previous year. Figure 20 shows the traded volumes at EU and the UK hubs from 2018 to 2020.

Figure 20: Traded volumes at EU and the UK hubs – 2018 to 2020 – TWh/year (four scales)



Source: ACER based on REMIT, Trayport and exchange operators data.

202 Gas trades at Europe's oldest hub, the British NBP, continued to decline for the sixth year in a row in 2020. The decline has mainly been caused by the emergence of TTF as the EU reference forward market venue. This was a role that was previously held by NBP. The closely linked, sterling-denominated, Belgian ZEE hub has also reported declining volumes over several years, in line with NBP. In 2020, its volumes were down by close to 40% YoY. The greater reduction in comparison to NBP in recent years has been partly driven by the expiration of the legacy capacity contracts on the IUK interconnector that links the two hubs, limiting price arbitrage trade. In addition, the Belgian virtual ZTP hub has successfully attracted national gas trade.

203 Other hubs where trade volumes declined YoY were the French TRF and the Hungarian MGP. A reduction in trade at the TRF was driven by lower gas demand as well as narrower summer/winter seasonal spreads, an important trade driver for the market. At the MGP, after the exponential growth seen in 2019, traded volumes stabilised at a slightly lower level in 2020, with lower hub sourcing demand from Romanian and Ukrainian shippers seen as relevant factors. However, volumes were much higher than in 2018. Section 4.3.1 presents a case study that analyses the drivers of progression of the Hungarian hub in recent years.

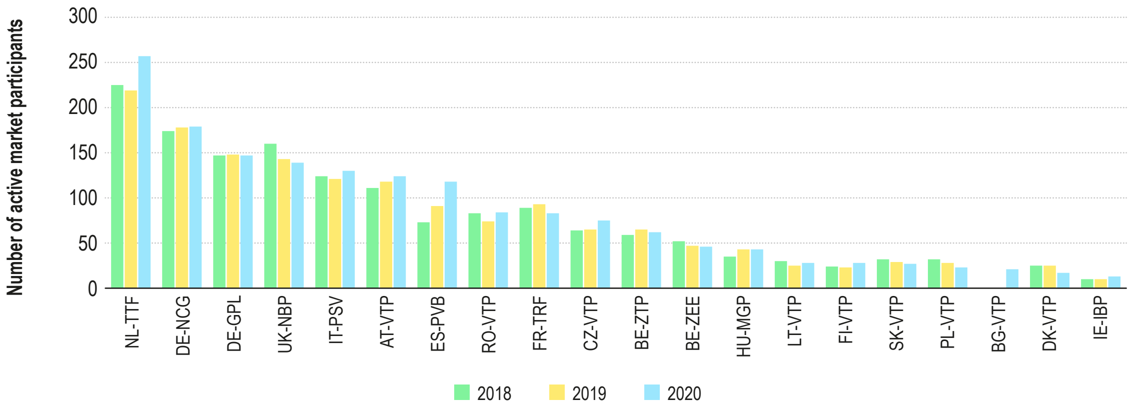
204 Traded volumes showed two-digit increases in the Austrian VTP, Spanish PVB, and the Czech and Slovak hubs. In Germany and at the Italian PSV, volumes rose more moderately. Against the backdrop of falling demand in 2020, the increase in traded volumes at all these hubs proves that the hub sourcing model has become integral to the IGM.

205 Among the group of illiquid hubs, which attracted no or very limited transparent hub trade in previous years, there were some positive developments in 2020. While traded volumes remained comparatively limited, liquidity in the Baltic region was enhanced by the inclusion of products delivering at the Finnish hub to the regional GET Baltic exchange. In addition, the merger of the Estonian and Latvian hubs also enhanced liquidity. In the SSE region, the recently launched Balkan Gas Hub exchange, which offers products for delivery at the Bulgarian VTP, increased its volumes throughout the year.

206 Looking forward, there are positive signs of development for some illiquid hubs in 2021: the Iberian exchange Mibgas commenced offering products for delivery at the Portuguese VTP[151] in Q1 2021, while the delayed launch of a gas trading platform in Greece is scheduled to become operational before the end of 2021[152].

207 Liquidity and competition of individual hubs are driven by, among other factors, the number of total active participants, benchmarked in Figure 21. The hub with the largest number of active market participants in 2020 was TTF, followed by the two German hubs, NCG and GPL. The Spanish PVB recorded the highest relative growth in the number of active market participants (+30%), while in absolute terms the highest increase was at TTF. There were noticeably fewer market participants active at the French, Danish and Polish hubs compared with 2019. In the case of the Polish hub, the pool of active counterparties narrowed for the second consecutive year in a row. This could reflect the impact of the provisions governing underground storage use, which have attracted discussion in recent years.

Figure 21: Estimated number of active market participants – 2018–2020



Source: ACER estimate based on REMIT data.

Note: Estimated based on registered users with at least one trade of standard contract for delivery at relevant VTP during the year.

Overview of trading activity in the Energy Community

208 Among EnC CPs, Ukraine remained the most ambitious and advanced in its efforts to develop a trading gas hub. While the situation in other EnC CPs did not progress significantly, Ukraine enacted positive regulatory changes in 2020 that contributed to increasing traded volumes and an increase in the number of market participants at the hub. In 2020, traded volumes at the Ukrainian UEEX exchange increased to 2 bcm – from just 0.3 bcm in 2019. In addition, the number of market participants doubled in this period. Most of the liquidity is concentrated on front month products, but the introduction of the day-ahead product trading season from February 2021 will enable more flexible trade.

209 The Ukrainian gas market has a variety of characteristics that support the liquidity of its hub. They include substantial gas consumption and production, plentiful and competitively priced UGS capacity and large IPs connecting the country with several EU gas hubs. Liquidity has also been reinforced since the Ukrainian incumbent, Naftogaz, started actively trading at the exchange and was followed to the venue by gas distribution companies. This step was related to the further deregulation of the gas sector and the lifting of Naftogaz's obligations to supply consumers at regulated prices[153].

151 See more details in Iberian exchange Mibgas.

152 See further considerations in this article.

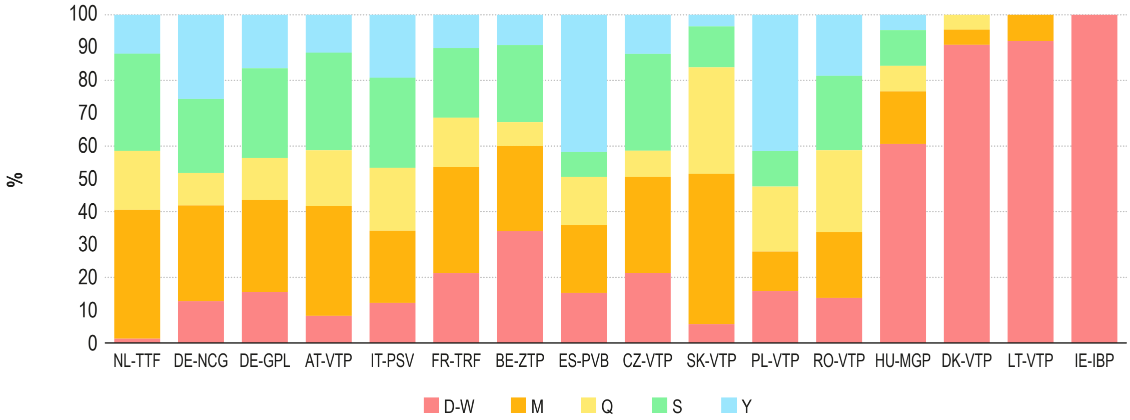
153 Since August 2020, Naftogaz is no longer obligated to sell gas at regulated prices to retail companies for the purpose of supplying households. However, the obligation to supply gas at regulated prices to district heating companies remained until May 2021.

210 Market design changes related to the implementation of the EU gas network codes have also supported the development of hub trading. The most influential have been the allocation of IP capacities in line with the CAM NC and the adoption of new transmission tariffs based on certain provisions of the TAR NC. The implementation of a daily balancing regime has also contributed to an increase in market liquidity, as the network users have the opportunity to trade in order to settle their imbalances before the TSO activates balancing services[154].

4.2.2 Breakdown of traded volumes per hub product

211 Figure 22 shows the relative importance of the different types of products traded by market participants at EU hubs in 2020 according to volumes traded.

Figure 22: Breakdown of traded volumes per product type at EU hubs – 2020 – % of traded volumes



Source: ACER estimate based on REMIT data.

Note: Product acronyms stand for: Y years, S seasons, Q quarters, M months, D-W refer to day-ahead and within-day.

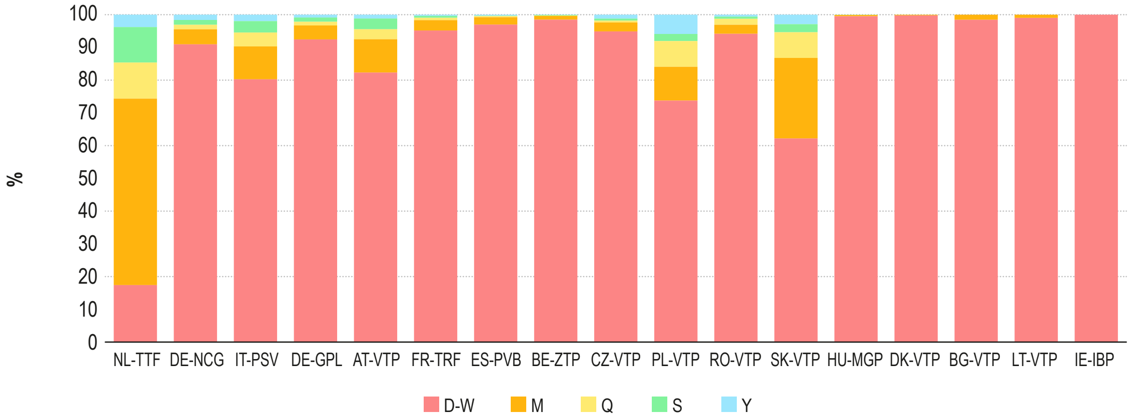
212 The relative share of spot products differs in relation to the hub forward liquidity depth. Day-ahead and within-day products make up relatively the smallest share of overall traded volumes at the TTF hub while their share at the advanced category hubs ranges from 10% to 25%. Spot products cover for most traded volumes at selected emerging and incipient category hubs.

213 On EU average, the contracts for monthly and seasonal delivery represent the largest share of traded volumes. Yearly contracts have a large share at the Spanish and Polish hubs, a result of local market specificities and legal obligations, but make up a relatively smaller share of traded volumes elsewhere. Furthermore, yearly products are not particularly liquid at those hubs, but are rather transacted in big volumes on a limited number of occasions.

214 Complementarily, Figure 23 shows the relative importance of the different types of products by number of trades. It shows that, with the exception of TTF, market participants trade most frequently spot products, although as analysed, these products represent a relatively small share of the total traded volumes.

154 In addition to balancing services, tolerance levels are still used, which to a certain extent hinders the continuous increase in liquidity.

Figure 23: Breakdown of trades per product type at EU hubs – 2020 – % of total number of trades



Source: ACER estimate based on REMIT data.

Note: Product acronyms stand for: Y years, S seasons, Q quarters, M months, D-W refer to day-ahead and within-day.

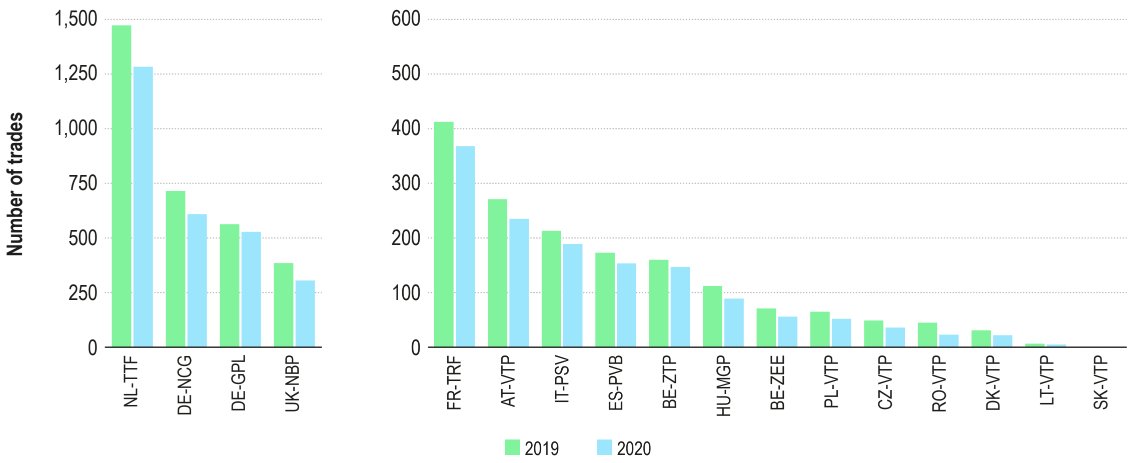
4.2.3 Liquidity and competition at spot and forward markets

215 This section analyses the liquidity and the competitiveness of EU gas hubs based on the results of the AGTM hub well-functionality' metrics[155]. First, hub's spot markets are analysed, followed by an overview of results related to hubs' forward markets.

Spot markets

216 The results of the AGTM metrics indicate that liquidity decreased slightly at many EU hubs' spot markets in 2020 compared to 2019. In contrast, liquidity increased in the French, Polish, Czech and Romanian hubs, and also the Belgian ZTP. The average outcome was partly a consequence of the lower gas demand caused by COVID-19, as spot markets – the last traded timeframe before delivery – are very responsive to actual demand changes. TTF performed best at all of the measured dimensions, including the tightest average bid-ask spread and the highest trading frequency. Other EU hubs with strong spot market performance in 2020 included both German hubs and the French TRF.

Figure 24: Spot markets trading frequency – average weekday number of trades of the DA product (two scales) – 2020 and 2019



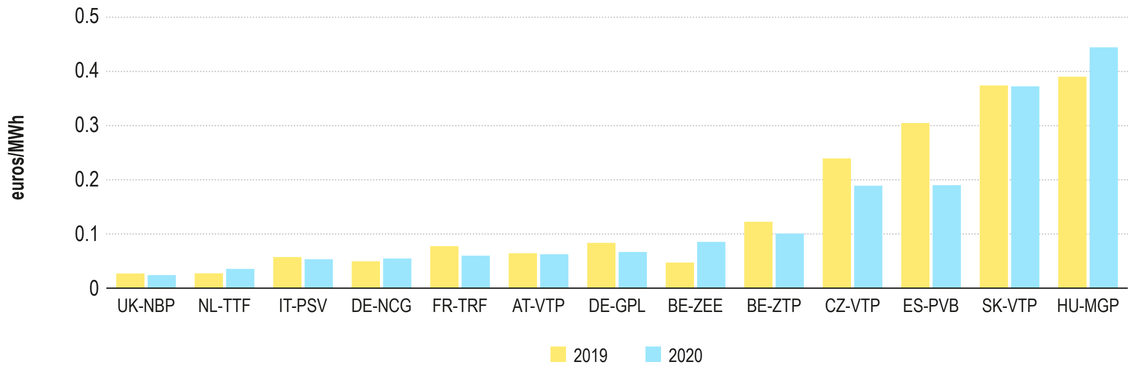
Source: ACER calculation based on REMIT.

155 Liquidity has been assessed with indicators measuring products trading frequency and bid-ask spread; and hubs trading horizon, amongst others. Competition has been gauged with an indicator measuring the concentration of market participants' in volumes of concluded trades in different timeframes.

217 Some changes in spot trade were regulatory-driven. The implementation of gas network codes continues to have a positive impact on hub trading activity as Section 5.3 analyses. In the specific case of Romania, a gas release programme was implemented mid-year, forcing gas producers to offer 40% of their production on a centralised market platform, while suppliers were obligated to bid on the platform. Although the release programme has had a positive impact on he Romanian spot market volume, some market participants have criticised it, including due to burdensome reporting obligations[156].

218 Figure 25 shows the evolution of the spot bid-ask spreads in absolute terms, i.e. measured in euros across EU hub spot markets. The price gap between the average buys and spot offers noticeably narrowed at the Spanish, Czech, French, Belgian ZTP, and German GPL hubs. When expressed as a percentage of the final gas selling price, the bid ask spread increased. This is due to the overall price reduction observed in 2020 already discussed in Section 2.1.3.

Figure 25: Bid-ask spread of EU hubs spot markets – 2019 and 2020 – % of DA bid price

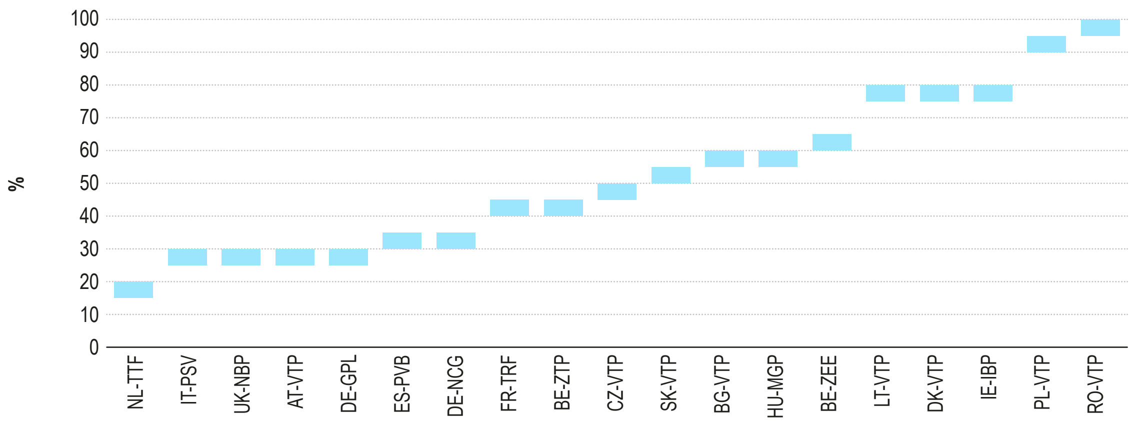


Source: ACER calculation based on ICIS data.

Note: The bid-ask spread is the difference between the prices available in the order book for an immediate sale (offer) and an immediate purchase (bid) of a physically settled gas product. The size of the bid-offer spread is a measure of transaction costs and of liquidity. The lower the bid-ask spread, the lower the transaction costs and the higher the liquidity.

219 The concentration of spot traded volumes remained consistent with preceding years. In general, a correlation between liquidity levels and concentration was observed, with the most liquid spot hubs exhibiting the lowest combined market share of the major three market players as shown in Figure 26.

Figure 26: Spot market concentration – 2020 – CR3 % for concluded DA trades



Source: ACER calculation based on REMIT.

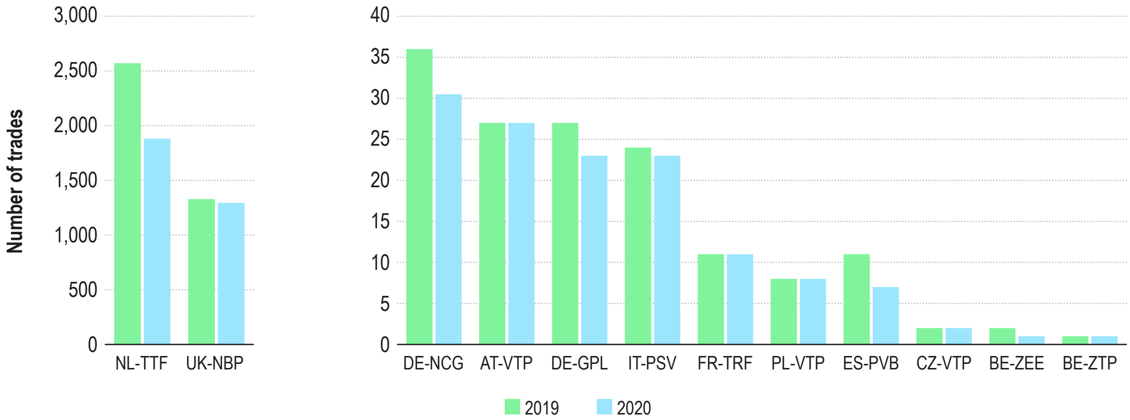
Note: CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest.

156 See some considerations in this ICIS press article.

Forward markets

220 Liquid forward markets are scarcer than spot ones. Most of the EU's gas forward and futures trading activity has been concentrated at the TTF hub for some years, a trend that continued in 2020. The trading activity of the month-ahead product, used as benchmark to assess the AGTM metrics, increased by more than a third at the TTF hub YoY, while it decreased, from already modest levels, at the other analysed EU forward hubs.

Figure 27: Forward markets trading frequency – 2020 and 2019 – average weekday number of trades of the MA product (two scales)



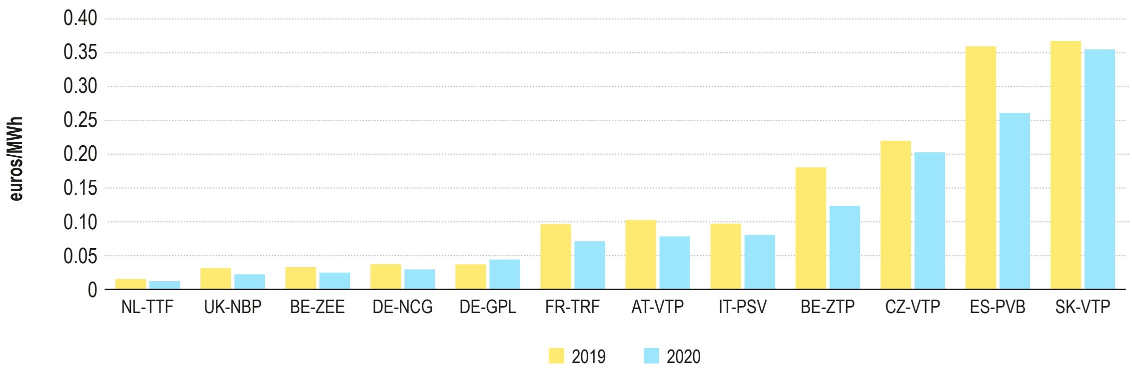
Source: ACER calculation based on REMIT data.

221 Despite their possible physical exposure in other markets, traders and shippers throughout Europe clearly favour TTF as the venue for taking forward positions due to its much higher liquidity that extends to products delivering several years ahead. However, such hedging strategies are possible due to the high levels of price correlation and price convergence of EU hubs' spot prices.

222 Outside of the TTF hub, trade of forward products is driven by local market dynamics and often influenced by gas storage changing aspects. For instance, according to market intelligence reports, liquidity of forward products tends to be higher in months when UGS capacity auctions take place at the French TRF, while the Czech's hub forward liquidity was boosted when Ukraine enacted a storage warehousing regime to attract EU shippers. The Czech hub acted as a proxy market to hedge those stored volumes.

223 Measured in absolute terms, the bid ask spread of the month ahead product also narrowed YoY at all of the assessed hubs except in the German GPL as analysed in Figure 28.

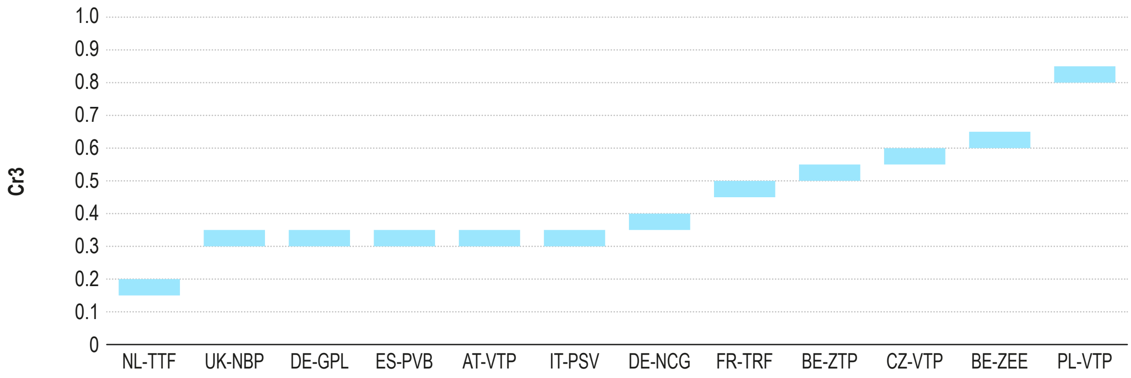
Figure 28: Bid-ask spread of EU hubs forward markets – 2019 and 2020 – % of MA bid price



Source: ACER calculation based on ICIS data.

224 With regard to forwards trade, concentration remained in line with levels observed in preceding years. Forwards' concentration shows slightly higher values than spot ones although the case is country specific.

Figure 29: Forward market concentration – 2020 – CR3 % shown as a range for concluded MA trades

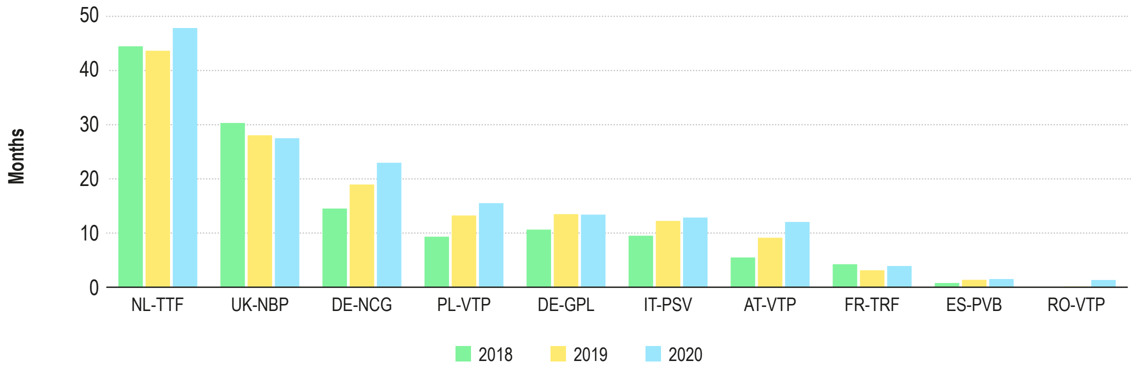


Source: ACER estimate based on REMIT data.

Note: Based on the market for the month-ahead product. CR3 measures the market share of the three largest market participants. The graph either shows the assessed CR3 for the buy or sell side, whichever was highest.

225 The trading horizon measures how far into the future traders can hedge their positions at the individual hubs, considering a sufficient threshold on average trades. Like in previous years, the forward trading horizons were largest at the two established hubs.

Figure 30: Hubs trading horizon – 2018 to 2020 – average horizon in months for minimum 8 trades



Source: ACER estimate based on REMIT data.

4.3 Gas hub categorisation

226 Figure iii in the Executive Summary shows a ranking of EU gas hubs based on the results of the AGTM market participant's needs metrics. The ranking remains unchanged in 2020 compared to the 2019 classification. While the analyses throughout Section 4.2. reveal some changes in liquidity at selected hubs, none of them were of a magnitude that would warrant a change in the functionality ranking.

227 TTF in the Netherlands and NBP in the UK continue as the only hubs in the established category. Even though liquidity at the two hubs continued to diverge in 2020, with TTF traded volumes again growing strongly and NBP recording a sixth straight year of decline (see Figure 20), the liquidity of the forward markets at TTF and NBP remain at a significantly higher level than at other EU hubs.

228 TTF has been growing by virtue of establishing itself as the preeminent hub for those either hedging exposure or seeking exposure to the EU gas markets and therefore attracting the bulk of forward trading activity in the EU. NBP, on the other hand, has seen its attractiveness diminish due to several factors, including the regulatory uncertainty created by Brexit. Furthermore, NBP was always compromised in its role as the EU's preeminent hub by the use of a different currency and by its relatively limited interconnectivity with the rest of the IGM.

229 The advanced hubs are a level below TTF and NBP in terms of hub functioning. They are characterised by a similarly liquid and competitive spot markets as those of the established hubs (with results that are to a large extent in line with the AGTM benchmarks) but also by forward markets where, when compared with the two established hubs, trade is less frequent, smaller in volume and with a shorter time horizon. The current group of advanced hubs are also similar in that they either have large domestic demand, are crossed by important gas transit routes or both. However, it should be noted that not all gas wholesale markets with large transit routes and domestic demand also host advanced hubs as is the case in Poland or Romania.

230 Liquidity at emerging hubs is at a lower level than at advanced hubs in terms of frequency and volumes of trade, which tend to be limited to spot markets. The current group of emerging hubs is small, yet appears to share some characteristics: comparatively limited interconnectivity with the rest of the IGM; support for national gas exchanges, limited or no multilateral OTC market; and medium-large demand.

231 The illiquid category includes both hubs where some trading of standard gas products on organised market venues took place in 2020 (e.g. hubs in the Baltics, Slovakia, Ireland, Romania and Bulgaria) and hubs where no standard gas products trades were reported for the year[157] (e.g. in Portugal, Greece, Slovenia and Croatia). In terms of hub functioning, the former sub-group shares several characteristics, such as high concentration and very limited gas traded volumes.

232 Most hubs in the illiquid category have comparatively low domestic gas consumption (except Romania) as well as limited transit volumes (except Slovakia and to a lesser extent Romania and Bulgaria) and limited interconnectivity with the rest of the IGM (except Slovakia and Slovenia).

4.3.1 Case study: Hungarian gas hub recent developments

233 The case study below discusses the broader market developments and the regulatory provisions that have backed the liquidity and competitiveness progression of the Hungarian gas hub in recent years. The case has been developed by the Hungarian NRA MEKH[158]. To make the exercise further wide-ranging, a couple of external stakeholders have been interviewed to provide views about the hub growth drivers, and the challenges and hurdles ahead.

234 The findings of the case are of particular interest to other markets in the region that are facing and seeking similar developments.

Introduction

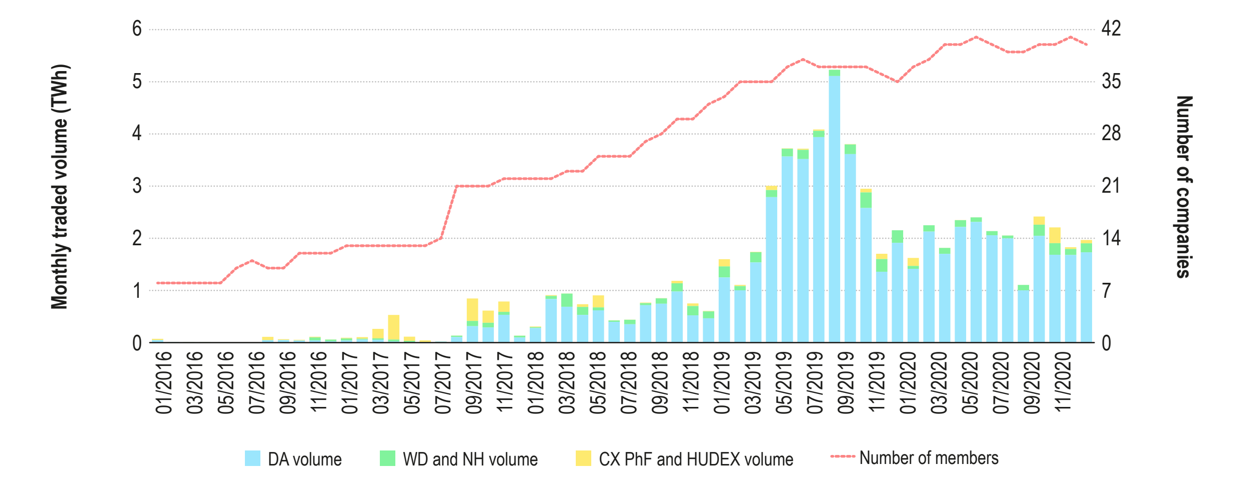
To assist the functionality of its virtual trading point – implemented in 2010 – the Hungarian NRA directed the Hungarian TSO to establish CEEGEX[159], an organised gas exchange in 2013. The gas volumes traded at the exchange remained modest in the initial years. However, sustained by the drivers discussed throughout this case study – and the introduction of the euro in 2018 – liquidity has increased, peaking in 2019. Spot products still constitute the big bulk of the traded volumes, even though curve products such as balance-of-month, seasonal and yearly contracts have been available since 2019.

157 This does not preclude the possibility that some non-standard gas contracts were traded bilaterally or that the TSO traded with market participants on gas balancing platforms.

158 An expanded analysis of the main drivers of liquidity development in the Hungarian gas hub has been published by MEKH.

159 Central Eastern European Gas Exchange.

Figure a: Hungarian gas hub liquidity evolution – TWh/month and number of companies



Source: MEKH based on CEEGEX, HUDEX.

The combined analyses and metrics discussed in Chapter 4 show the gradual upgrading of the Hungarian hub functionality. Since 2019, the market qualifies as an emerging hub, an upgrade from the previous incipient status160.

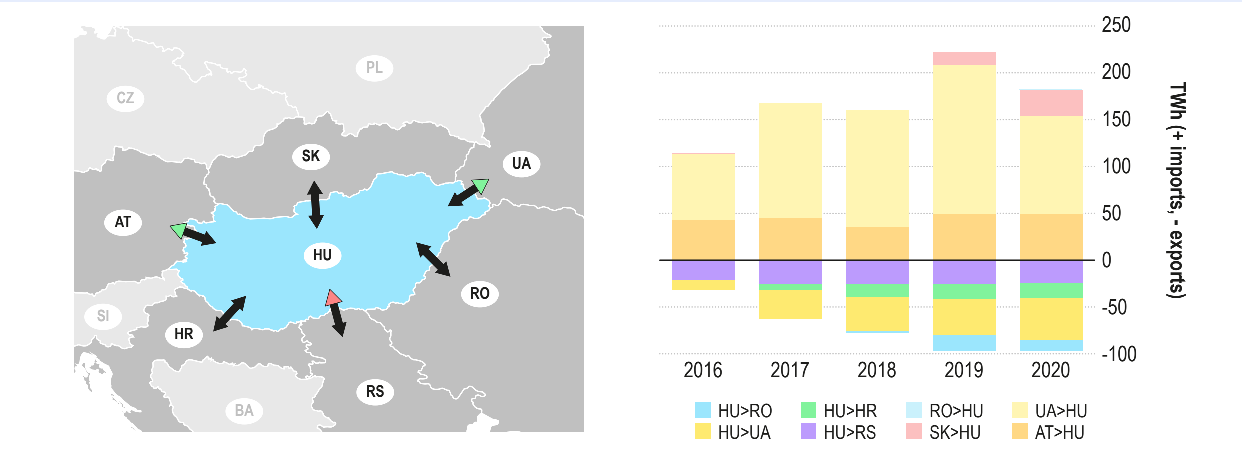
i. Drivers supporting the hub liquidity

The key preconditions assisting the development of the Hungarian hub have been the enhancement of its physical interconnectivity and the adoption of market oriented regulations. Beyond that, specific external factors such as the rising transits across the country have contributed to the hub's liquidity growth.

a. Infrastructure expansion and enhanced regional supply role

Figure b offers an overview of the Hungarian gas market interconnections and the evolution of the cross-border flow nominations since 2017. The market is now linked to six neighbouring markets, while a couple of new interconnection projects are under consideration.

Figure b: Overview of Hungarian market cross-border IPs and trade nominations – TWh/year



Source: MEKH based on FGSZ.

Note: The red arrow refers to reverse capacity expected from October 2021. The green refers to reverse interruptible projects[161]. In the figure to the right, positive values refer to import nominations into Hungary and negative to export nominations from Hungary.

160 See at Figure i an analysis of EU gas hubs categorization in accordance to their functionality degree. Emerging hubs refer to those "improving hubs although from a lower base, taking advantage of enhanced interconnectivity and regulatory interventions"

161 An incremental capacity auction was held in 2020, testing the interest for firm export capacity to Austria, but the economic test was unsuccessful. The decision to upgrade the current reverse capacities to firm is under consideration. Gas can be delivered from Hungary to Austria via Slovakia.

Traditionally, Hungary has imported gas for domestic consumption from Ukraine and Austria, while Russian transits to Serbia and Bosnia and Hercegovina were separated from the domestic transmission system.

Since 2016, a series of events have enhanced the utilisation of the country interconnectors for export and complementarily have resulted in a higher interest of foreign companies, as well as some domestic market players, to source and trade gas at the Hungarian hub.

1. Gas exports from Hungary into Ukraine have emerged following the rising interest of Ukrainian suppliers to acquire gas at EU hubs, as well as from EU shippers' interest to make use of the country's large UGS sites. Section 2.2.4 has discussed the favourable conditions to do so.

2. Since 2017 Gazprom has favoured to deliver gas to Croatia via Hungary, instead of via Austria and Slovenia, following some contractual and tariff revisions.

3. Flows into Romania have increased since 2018 due to a more beneficial price spread positions.[162]

Increasing gas purchases at the Austrian VTP with destiny to Ukraine resulted in persistent congestion on the Austrian-Hungarian link. At the end of 2019, more gas also entered Hungary directly from Slovakia. This was due to the uncertainties about the continuation of the transit of Russian gas through Ukraine.

MEKH has assessed the significance of this enhancing regional supply role and the associated higher presence of foreign companies in boosting the liquidity at the hub by dividing the active hub traders into three groups:

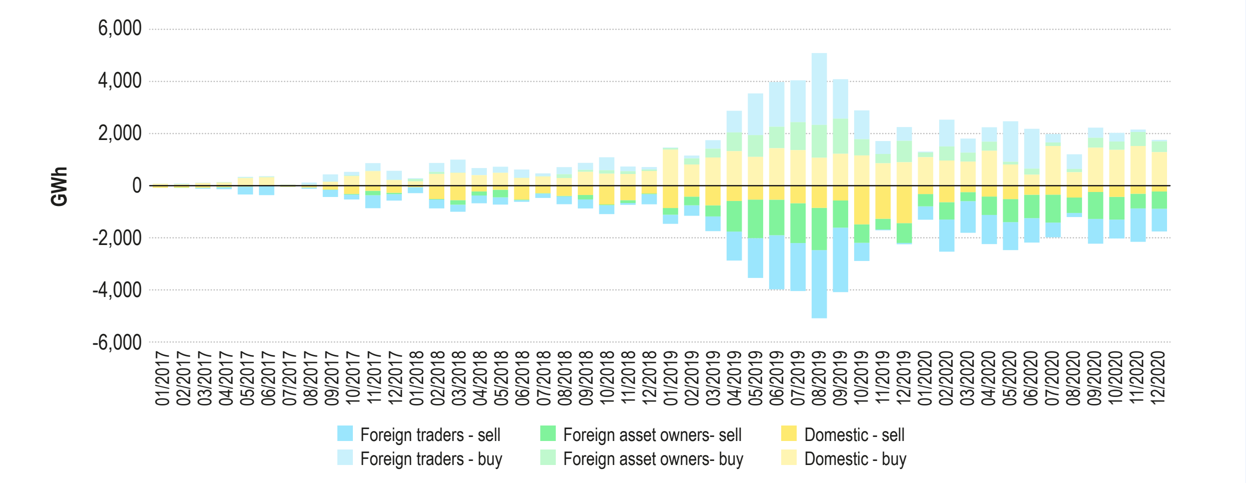
1. Domestic companies are those with significant operations in Hungary: power plant owners, industrial companies, retailers, and the TSO.

2. Foreign asset owners include regional utilities and other regional companies owning physical assets (e.g. network).

3. The third group is composed of international trading companies without significant footholds in the neighbouring countries.

Figure c tracks the trades of each of those categories. It shows how, since 2019, foreign companies have made a remarkable contribution to the liquidity expansion. Interestingly, those foreign companies are active on both sides of the market. Further than that, as the exchange has become more liquid, domestic companies also increased their purchase at the exchange, even if their activity has remained more limited on the sell side.

Figure c: Turnover of domestic and foreign companies at CEEGEX



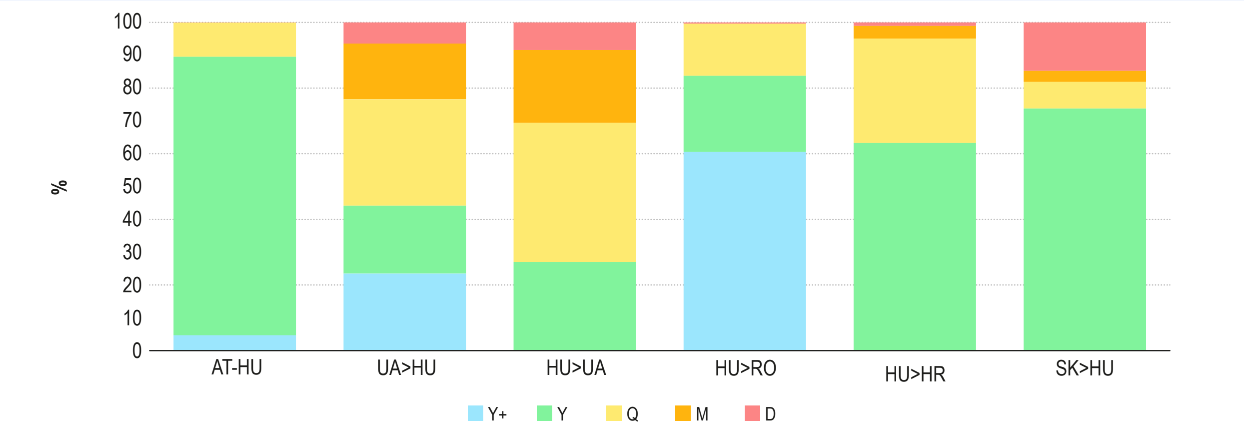
Source: MEKH based on CEEGEX data.

162 Among the reasons: a new turnover tax and special selling obligations imposed on Romanian gas producers and traders since January 2019, resulting in higher Romanian prices.

b. Market rules and NCs implementation

The implementation of the CAM NC in 2015 has facilitated access to the hub and the associated transactions. Beyond the virtual trading point, a comprehensive entry–exit system has been in place. Today, and in accordance with CAM NC, standard bundled capacity products are marketed at the EU cross-border IPs, whereas at least 10% of these available capacities are reserved for short-term products. Although congestion can still occur[163] at the most demanded IPs bordering Austria and Romania, the larger availability of short-term products has provided shippers enough flexibility to manage their portfolios. The introduction of CMP UIOLI in October 2020 has also contributed. Figure d offers an overview of the dominant capacity products per duration at the IPs.

Figure d: Breakdown of capacity bookings at the Hungarian cross-border points



Source: MEKHS based on FGSZ.

The implementation of the tariff network code has also supported cross-border trading activity. Increasing transit flows enabled to reduce total tariff levels. A postage stamp methodology was implemented in 2005. Since then the entry-exit split became more even in several steps (from 80/20 to 40/60). Multipliers for non-yearly capacity products were also reduced; the multiplier for daily product dropped from 3.05 in 2016 to 1.9 in 2020. Lower tariff levels and more favourable pricing of short-term products supported cross-border trade and reinforced transit flows through the country. The ACER revision of the Hungarian new reference price methodology (RPM) offers further details on the subject[164].

Finally, the implementation of the balancing network code since 2015 has incentivised short-term transactions at the exchange between the network users that seek to balance their positions. Complementarily, it has also promoted the residual balancing actions from the system operator.

- Regarding the network users' activity, modest transactions occurred in the first years, as the information about their within-day positions was scarce. Therefore, the NRA set the small adjustment in the calculation of the imbalance charge at 1%, that being usually cost-competitive against the trades' bid-ask spread; as a result, users typically settled their imbalances with the TSO. Subsequent IT development improved the information provision for traders. Then, from January 2020, the small adjustment was increased to 6%: this boosted intraday trading[165].

- Regarding the TSO balancing actions, and in line with the merit order set by the BAL NC, standard short-term products got priority. Today, most balancing transactions take place on the within-day market. The ACER balancing implementation reports track the evolution and role of TSOs showing how, in 2020, TSO's interventions were 13% lower than in 2019.

The availability of more flexible storage services may have also played a role in hub development. Hungary has ample UGS capacities (69.6 TWh) while the UGS operator offers a range of flexible services. Although the regulated UGS fee has remained flat since 2017, the UGS operator can provide a 30-40% discount.

163 See the detailed analysis on the latest ACER congestion monitoring report. Some legacy unbundled capacity contracts at the Austrian and Romania borders hindered the more efficient utilisation of the IPs. In order to facilitate a better matching, interruptible capacities were also marketed at these points. In addition, the congestion management procedure firm day-ahead use it or lose was introduced from October 2020.

164 See ACER Analysis of the Consultation Document for Hungary.

165 As an illustration, the share of trades involving the TSO declined from 70% in 2019 to 50% in 2020.

235 ACER has discussed the considerations expressed in the case study with relevant stakeholders active in the Hungarian gas market. They offered additional expert views about the drivers described in the case study and highlighted the challenges that could still hinder the further development of the Hungarian hub.

236 The stakeholders consulted recognise an enhanced Hungarian market role for sourcing and transiting regional supply, backed by the recent infrastructure expansion, together with the implementation of NCs have assisted the hub's liquidity growth in recent years. However, the general perception is that the Hungarian hub forward liquidity is still very limited. The exchange is chiefly a spot physical trading venue, while the opportunities to hedge forward prices and do financial trade are very narrow.

237 It is perceived that its ability to attract and manage the sourcing of gas transited abroad, particularly to Ukraine, will be a key factor that will determine the actual role that the Hungarian hub will play in the future. Most of the sourced gas is now hedged at other more liquid forward hubs, such as at the adjacent Austrian VTP[166] or contracted directly OTC. In this context, the Hungarian exchange now serves to balance and optimise those contracts in the spot timeframe. A larger forward liquidity at the Hungarian hub could enhance its hedging and supply significance at regional level.

238 To enhance the forward liquidity of the Hungarian hub, it would be beneficial to promote enhanced forward trading activity of the main national suppliers. However, the presence of these companies remains quite limited, due to their preference for OTC bilateral supply contracts. The designation of the Hungarian incumbent supplier (MFGK) as CEEGEX market maker is a positive step in enabling forward liquidity market enhancements.

239 Reducing the persistent congestion at the Austrian border would also assist the Hungarian hub progression, according to stakeholders. The implementation of the CAM and TAR NCs and the introduction of UIOLI congestion mechanisms represent supportive regulatory steps in that direction. As referred in the case study, further new infrastructure has however not been supported by market tests, as the sector perceives that in the long run the current congestion could decrease because of the use of alternative routes[167].

166 The month-ahead product tends to set the reference of the supply contracts, attracting most of the trade and hedge interest. While some Ukrainian shippers may be directly sourcing there, the big bulk of the activity is deemed to be carried by EU shippers that then deliver the gas to Ukrainian counterparts.

167 For example Gazprom has expressed its preference to deliver its supply LTCs to Hungary from Serbia across the forthcoming Balkan Stream, what could release up to 2 bcm/year of contracted capacity at the Austrian-Hungarian border. Also the somehow competing interconnection capacities of Ukraine with Poland and Slovakia could expand in the years to come.

5 Impact of gas network codes on market functioning

240 This Chapter looks at the market effects brought about by the implementation of the gas network codes and Commission Guidelines in recent years[168]. The analysis is structured in four different subsections that look at each individual code, even though the effects of their gradual implementation are interrelated. In addition, a clear identification of the codes' market outcomes cannot always be clearly established. This is due to, among reasons, non-regulatory changes to market conditions, differences in implantation of the codes per MS[169] as well as the continuing effects of prevailing LTCs.

241 All EU network codes are applicable in the EnC CPs. However, their implementation only commenced in 2020, with Ukraine being the most advanced. Therefore, the market effects have only been assessed to a limited extent for the EnC for 2020.

5.1 CAM NC effects

242 The CAM NC code was introduced to govern how shippers access cross-zonal transportation capacity. The code has increased the transparency, predictability and standardisation of the allocation of capacity at IPs[170], with the objective of increasing the competition in and integration of the IGM. Among other regulatory changes, the CAM NC established the use of market-based auctions of primarily bundled products of standardised duration, managed through centralised booking platforms[171].

243 Most CAM NC provisions have been mandatory since November 2015, with additional provisions coming into force in 2017, following an amendment to the CAM NC. The amendment was introduced to improve some aspects and to add the so-called incremental capacity process[172]. Some MSs implemented a large number of the CAM NC provisions before the abovementioned dates.

5.1.1 Expiration and replacement of legacy transportation contracts

244 To assess to what extent the CAM NC implementation has contributed to increasing competition and market integration, the legacy of the pre-CAM period, which comprises both capacity and commodity long-term contracts, needs to be taken into account. As Figure 31 shows, at the EU scale, the IP capacity bookings that shippers had made before the CAM NC came into force are gradually expiring. Nonetheless, at the end of 2020 they still accounted for more booked capacity than was booked through the CAM auctions[173].

168 The gas network codes and guidelines are comprised by the congestion management procedures guidelines (CMP GL), which sets out rules for identifying and alleviating contractual congestion at interconnection points; by the capacity allocation mechanisms network code (CAM NC), which sets out rules for allocation of transportation capacity rights at interconnection points; the interoperability network code (INT NC), which sets out rules for harmonisation of interconnection agreements between adjacent TSOs; the tariff network code (TAR NC), which sets out the process and rules for setting tariffs of transmission networks; and the balancing network code (BAL NC) that sets out the rules for balancing gas networks.

169 The implementation of the NCs brought a helpful degree of harmonization of rules across the IGM. While, the regulatory regimes of some frontrunner MSs were well aligned with EU NCs, they implied a substantial policy change in others. This adds some extra challenge in terms of ascribing the NC's market outcomes.

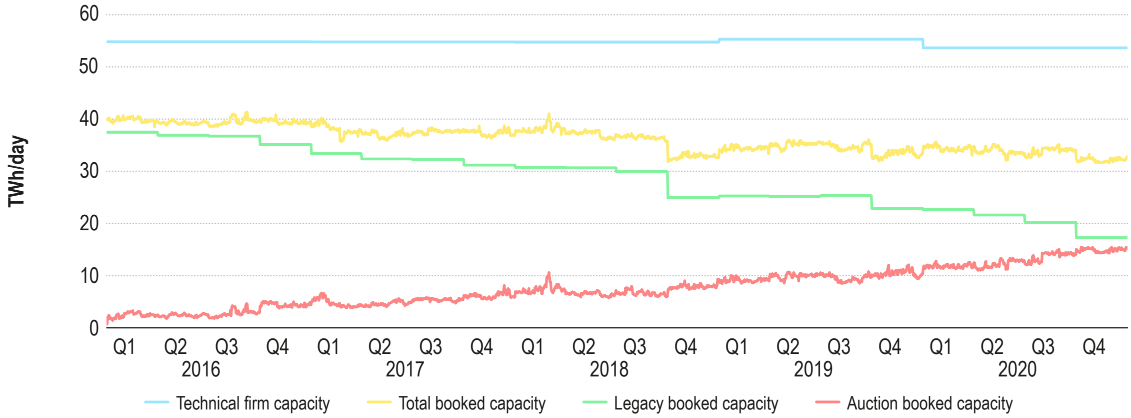
170 The CAM NC applies to all intra-EU interconnection points and may also apply to entry points from and exit points to third countries, subject to the decision of the relevant national regulatory authority. It does not apply to exit points to end consumers and distribution networks, entry points from LNG terminals and production facilities, and entry points from or exit points to storage facilities.

171 Before the implementation of the CAM NC, capacity was allocated via varying procedures, arguably not that market-based as auctions, which in some cases gave priority to the incumbent. The CAM NC also overcame difficulties created by lack of standardization of units.

172 The amended CAM NC includes rules for determining and marketing incremental capacity. It also contains provisions for a capacity conversion service of unbundled capacity products as well as for harmonising the main terms and conditions for bundled capacity products. New requirements for offering interruptible capacity and new auction dates and rules for long-term capacity products were also introduced.

173 The situation may be even less favourable at some non-CAM relevant points, although it could not be analysed in a similar way due to a lower level of transparency.

Figure 31: Evolution of booked capacity at EU CAM interconnection points: total, legacy and CAM auction booked capacity – MWh/day – 2016–2020

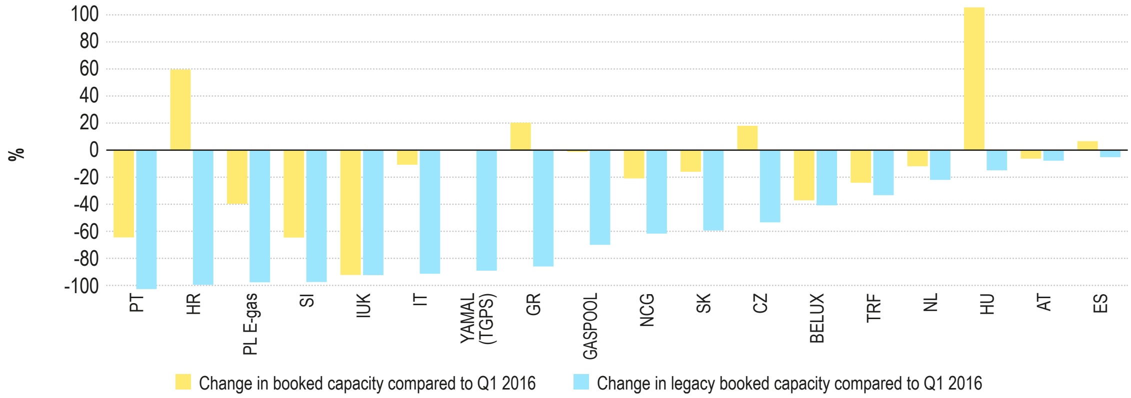


Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA data.

Note: The figure includes data for the CAM relevant IPs that have been in operation throughout the monitored period and excludes IPs that have ceased to be bookable points without a successor (e.g. Liaison Nord-Sud in France, Julianadorp the Netherlands, etc.). Interconnectors linking zones to LNG regasification facilities are out of scope of the CAM NC and are therefore not included in this assessment. Interconnectors with 3rd countries are included if they have been designated as CAM points by the relevant authorities.

245 Aggregated EU cross-zonal booked capacity was in decline up to the end of 2018. However, the cross-zonal booked capacity has remained relatively stable since then. On average, expiring legacy transportation bookings have been replaced at a relatively high rate, despite some clear differences among systems, as Figure 32 shows.

Figure 32: Estimated change in total and legacy cross-border booked capacity between Q1 2016 and Q4 2020 at EU CAM IPs of selected market areas – % of capacity in place in Q1 2016 that expired



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA.

Note: See Figure 31 considerations that also apply here. The left column refers to the total booked capacity variation and the right column to the percentage of legacy contracts that expired, both for the IP-sides relative to the market area.

246 By the end of 2020, some legacy long-term capacity contracts had expired in all of the assessed transmission systems. In the Spanish[174] and Austrian market areas, the expired capacity represented a small share of the total long-term capacities booked in Q1 2016. However, at the Portuguese, Croatian, Polish, Slovenian and Italian transmission systems, the drop was significant.

247 Although a relatively high proportion of the expired LTCs have been replaced with CAM auctioned products, not all were. As a result, the total volume of contracted capacity has decreased since 2016 in most market zones. In the Hungarian and Czech zones, enhancements have been made to their transit capacities and overall role in recent years and there has consequently been an increase in overall booking levels in 2020 compared with 2016. Conversely, in some MSs, for example in Slovenia, the low replacement of legacy transportation contracts may be linked with loss of their transit role to a competing route.

174 However, since January 2021 more than 90% of the prevailing long-term contracted capacity from Spain into Portugal has expired.

248 The likelihood that cross-zonal bookings will further increase in the future is overall small. This is due to the uncertainty surrounding future gas demand linked to a gradual shift into decarbonised gas mainly from domestic production, which will partly limit cross zonal gas trade. A higher reliance on LNG imports compared to pipeline gas supply imports has been seen in recent years in zones such as Portugal, Belux and the French TRF and is expected to continue in the future.

249 With regard to individual IPs, legacy capacity at some interconnections has already fully expired, while prevailing contracts are only set to expire in the coming decades at others. Figure iii in the Executive Summary has shown the evolution of past and future aggregated bookings on the EU average, listing the legacy contracts' expiration dates at selected key interconnection points.

250 By the end of 2020, a number of significant legacy contract expirations had taken place. For instance, at the IUK interconnector that links the UK and BELUX markets, most legacy capacity expired at the end of the 2017/2018 gas year. Likewise, almost all legacy contracts expired on the IP that links the Italian and Austrian markets, on the Italian side, by the end of the gas year 2018/2019. By the second quarter of 2020, all LTCs expired between the German Gaspool market and the Yamal transit system in Poland. Gas shippers have responded differently to these contracts expirations. Considerations for these three example are outlined below.

251 In the case of IUK, the expired capacity has not been replaced on a long-term basis. Instead, shippers have booked capacity for shorter durations, although mostly via the Implicit Allocation Mechanism and not via the CAM auction mechanism[175]. As shown in Figure 33, the booking pattern that has emerged in this interconnector is seasonal, with shippers acquiring rights to flow gas from the UK in summer and into the UK in winter.

Figure 33: Booking patterns post legacy transportation contract expiration – IUK – 2018–2020

Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA.

252 While the impact of the shift has been notable on the actual IUK's use, it has not had a discernible impact on market price convergence so far. The difference in the spot price of gas between the two markets (UK and BeLux) has remained, on average, narrow, with no increase in the frequency of days with high spreads. Broad accessibility to similarly competitive supply sources, such as LNG and Norwegian supplies, has favoured the NBP-ZEE price convergence, despite the lower use of the direct IUK link. However, such a specific outcome may not follow important expirations elsewhere, as will be discussed further below when referring to the role of tariffs – and sunk LTC costs – on price formation.

175 IUK related capacity has remained on offer via CAM auctions on the PRISMA platform.

253 In the cases of the Italian–Austrian interconnector and the Yamal interconnector to Germany, the replacement of the expiring capacity has been larger. In the case of the former, the legacy contract on the Austrian side will fully expire only in 2023, so shippers have been replacing the mismatching capacity on the Italian side, although only on a year ahead basis.

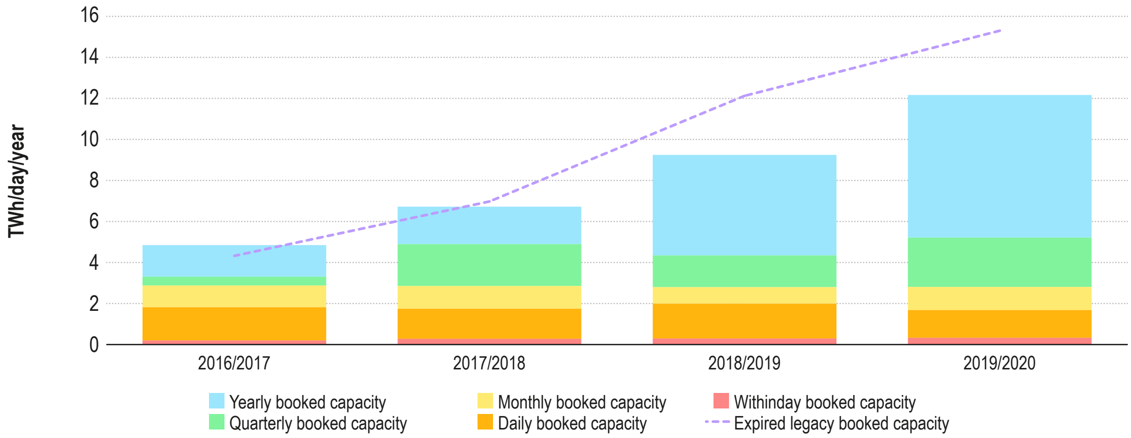
254 At Yamal, the legacy contract expiration (which coincided neither with the gas year nor the calendar year) was surrounded with uncertainty about its replacement. However, shippers have so far booked a portfolio of products that have effectively replaced the contract. Nonetheless, and similarly to the Italian case, they were only willing to book on a year ahead basis. This cautious booking pattern of acquiring capacity at most on a year ahead basis is becoming an overall dominant trend, with a few exceptions, as described in the next section.

5.1.2 Gas transportation capacity booking trends since CAM implementation

255 The CAM NC standardised capacity auction schedule has provided shippers with better predictability of when and under what conditions transportation capacity is available. As shown in Figure 34, there was immediate demand for shorter-term products (i.e. within day, day-ahead and month-ahead) which enable better profiling of bookings according to shorter-term flow needs. However, the volumes booked with monthly products or less have remained at a similar level since then.

256 On the other hand, longer duration products, i.e. quarterly and yearly products, attracted relatively less interest in the first years after the implementation of CAM NC. However, in 2019 and 2020, they became the products with which the majority of new transportation capacity was booked.

Figure 34: Gas capacity booking trends - breakdown of CAM booked transportation capacity and expired legacy booked capacity – TWh/day yearly average – 2016–2020



Source: ACER estimate based on ENTSOG, PRISMA, RBP and GSA.

Note: See Figure 31 considerations that also apply here.

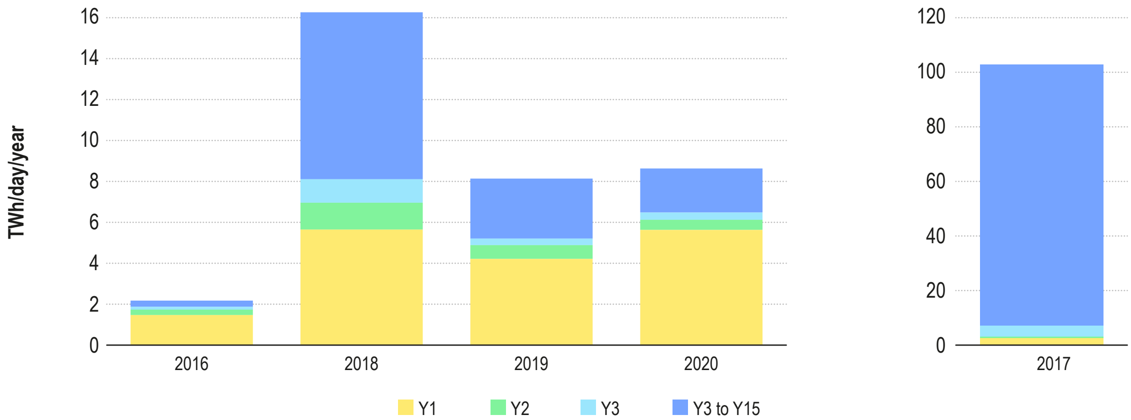
257 The increased frequency of the offer of quarterly products and timing the auction closer to delivery for the yearly product[176] provide an explanation for the increased attraction of quarterly and yearly products. These are regulatory in nature as both are recent amendments to the CAM NC. As discussed in the Recommendations section, the sector is also considering if further flexibility could be implemented in new code revisions[177]. In addition, the increased transparency regarding the future level of tariffs resulting from the implementation of the TAR NC has also contributed to the increased attractiveness. Finally, quarterly and yearly products have lower tariff multipliers that make these products more cost-competitive – see further consideration in Section 5.2.

176 The session of the yearly capacity auction was moved from March to July in order to bring it closer to the start of the gas year. This theoretically means network users have better forecasts of their needs when entering the auctions as well as more reliable information regarding future tariff levels.

177 As said, ACER and ENTSOG are working on issuing some proposals on the subject, exploring them via an open public consultation. Higher flexibility has been also solicited by EFET via the FUNC Platform.

258 As indicated, the first gas year following the yearly capacity products' auction is the most demanded one, as shown in Figure 35. The exception were the auctions that took place in 2017, when shippers booked substantial volumes of new and additional year ahead capacity at several IPs, some up to 2039. These bookings were on the whole related to the need to secure supplies from Nord stream 2 pipeline across the EU. They include IPs in Germany, Czechia, and Slovakia.

Figure 35: Yearly gas capacity product booking trends – two scales – 2016–2020



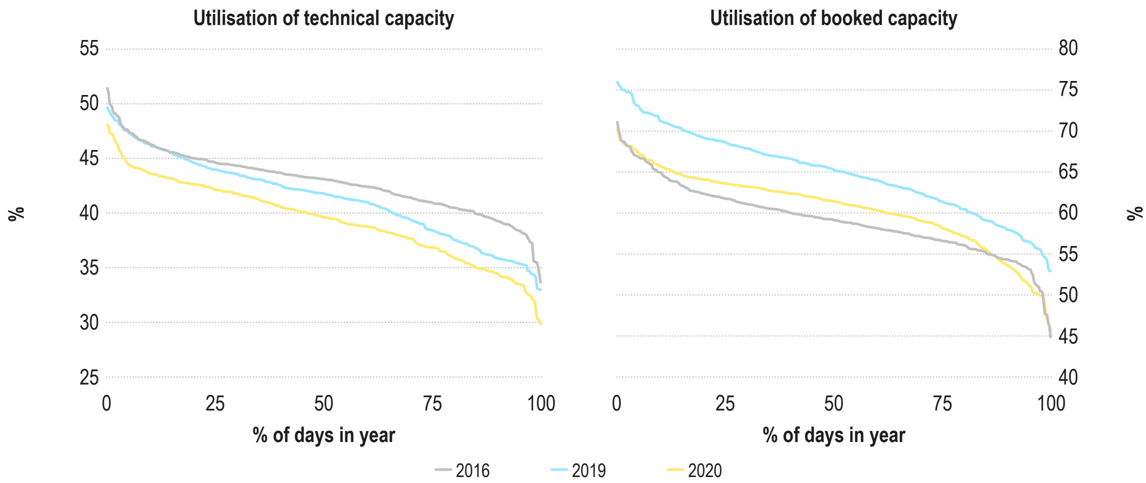
Source: ACER estimate based on PRISMA, RBP and GSA data.

Note: the year on the horizontal axis is related to the date of the auction not the date of delivery.

5.1.3 Utilisation of cross border capacity in the internal gas market

259 While the primary cross-border interconnection capacities were initially built to enable and secure gas supplies at individual MSs, the cross-zonal interconnection possibilities have expanded since in order to further promote competition between different supply origins. This integrated network is now the backbone of the IGM. This is an important context to bear in mind when interpreting the statistics of Figure 36, which shows the average utilisation of all EU interconnection points.

Figure 36: Shippers' utilisation of technical (left) and booked (right) capacity at EU interconnection points – 2016, 2019 and 2020



Source: ACER estimate based on ENTSOG data.

Note: the horizontal axis represents days of a given year, ordered from highest to lowest value.

260 From an EU-wide aggregate perspective, two interlinked trends are manifest when assessing the IPs utilisation: the utilisation of technical capacity has decreased in recent years, while the relative utilisation of booked capacity has increased.

261 The reduction in gas demand across the last couple of years only partially explains the decreased use ratio of technical capacity. The reduction is not due to an increase in available technical capacity (as for the purpose of this analysis, only IPs that have been in operation from the beginning of the observed period have been included). Rather, a crucial factor behind the reduced demand has been the switching from pipeline to LNG supply since the end of 2018.

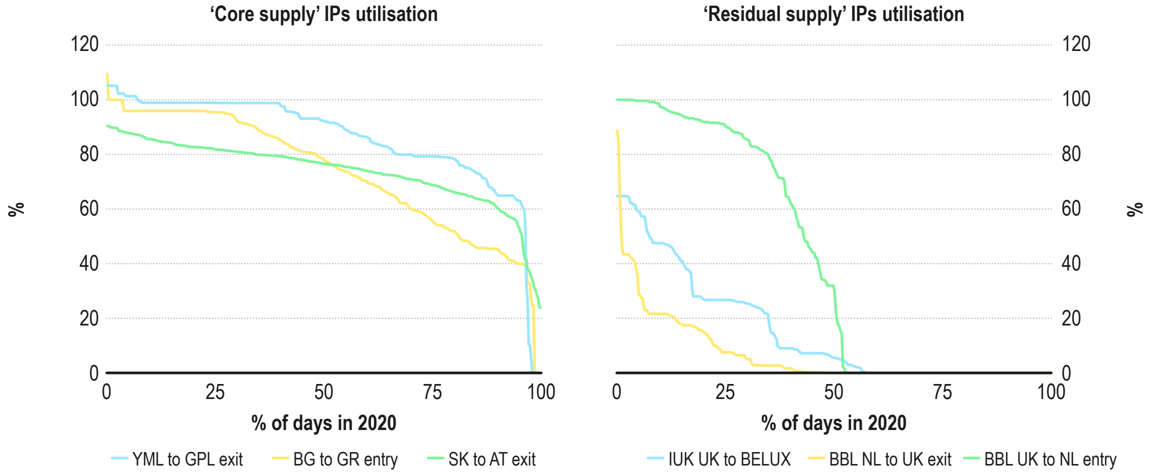
262 The increase in the use of booked capacity, a measure of how effectively shippers use their acquired capacity, is explained by an enhanced profiling of booking needs. By better combining a portfolio of long and short-term products, shippers have been able to further match their seasonal supply requirements. In addition, they have better factored into their bookings hub price signals, rather than chiefly securing capacity long term to cover peak demand, as was the more dominant case in the past.

263 Enhanced capacity profiling is a stated goal facilitated by the CAM NC. The CAM NC promotes the use of IPs by those network users that can generate the highest value in the market, which in turn impacts positively on the transparency and efficiency of the price formation in the IGM.

264 When analysing individual cases, the IPs utilisation ratios are quite diverse. They vary from what could be described as continuous, high utilisation to a variable, demand responsive one (the latter includes also very sporadic, limited utilisation and even no utilization at all).

265 These utilisation patterns show the dominant supply function that the individual IPs perform. This role can range from facilitating core, baseload supply (even to several market zones) to easing competing supply and assisting price arbitrage or even only idly guaranteeing a level of security of supply. Figure 37 shows the utilisation patterns at two types of IPs in 2020: 'core supply IPs' and 'residual supply IPs'. The first group encompasses Yamal, Kipi and Baumgarten IPs, while the second examines the use of the interconnectors between the UK and the Continent. Despite the dominant supply function, individual shippers active in a given IP may have slightly diverse roles as well.

Figure 37: Shippers' utilisation of technical capacity at selected interconnection points – 2020



Source: ACER estimate based on ENTSOG data.

Note: the horizontal axis represents days of a given year, ordered from highest to lowest value.

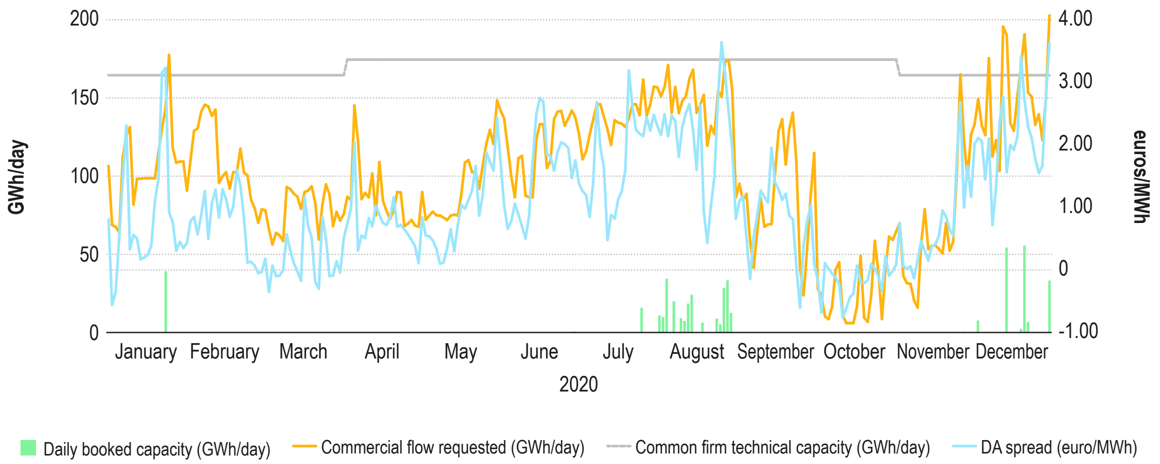
266 Several factors influence the utilisation of IPs. Such factors include the demand of the accessed market, the existence of competing supply routes and their concentration, the prevalence of LTCs and the cost of the different capacity products. In addition, and particularly for those more dynamically used, the relative position of the interconnected hubs' price spreads and the transportation tariffs is determinant. The listed factors tend to also be co-dependent. For example, transportation tariffs influence price spreads while the combination of the two influences network users booking behaviour, particularly for short term products.

267 The utilisation of the IPs included in the 'core supply' category was not visibly diminished by the expiration of some legacy transportation contracts. While gas commodity long-term contracts and related supply obligations have backed for years their high utilisation, the lesser availability of competing supply routes have as well contributed to such an outcome. However, this is starting to change. As outlined in Section 2.2.1, TAP has commenced the diversification of supplies into Greece, Bulgaria and Italy, while Gazprom, the main Yamal network user, is likely to divert part of their bookings and flows to Nordstream 2.

268 The IPs within the 'residual supply' group have been utilised for several years with a rather different pattern. In fact, the 'residual supply' group was barely utilised for almost half of the days in 2020. This was due to limited hub price arbitrage opportunities. However, their utilisation is now more oriented to service seasonal flow patterns partly related to storage. Despite being infrequently utilised, it is important to note that the tariff for their use tends to be used as a ceiling to the price spread between the markets they connect, as will be discussed in Section 5.2.

269 Many IPs show utilisation patterns that combine elements of the two types of categories described above. A portion of their capacity is utilised in a baseload fashion, while another portion is utilised in a variable way that is responsive to hub price signals. An example is shown in Figure 38, which illustrates the aggregate utilisation of the VIP Pirineos in the direction from France to Spain against the price difference between the French TRF hub and the Spanish PVB[178].

Figure 38: FR to ES commercial flow, daily booked capacity and technical capacity (left axis) and day ahead TRF-PVB price spread – 2020



Source: ACER estimate based on ENTSOG data.

270 Commercial flows are price responsive, in the sense that higher hub spreads tend to trigger higher flows. Approximately 30% more of the VIP capacity was used on average on days with a substantial price difference (e.g. in excess of 1 euro/MWh) than on days with a moderate price difference (lower than 0.5 euro/MWh). Part of this capacity was acquired new with day-ahead products, with the likely impact of limiting the growth of the price difference and thus contributing to market price integration.

271 Given the referred continued gradual expiration of legacy contracts and the shippers focus on short term market optimisation, the trend of growing utilisation of booked capacity is likely to reinforce. The utilisation of technical capacity, however, may fluctuate in the near future in line with shippers' arbitrage between LNG and pipeline supply, with IPs' tariffs playing a crucial role.

178 While the analysis focuses on this IP direction, the reverse flow is equally price responsive. In fact, across the year 2020 the physical dominant direction of the flow changed in response to price signals making the Spanish PVB more cost competitive.

CAM NC implementation progression at EnC CPs

272 In a related development, the first auctions of standardised IPs capacity between Ukraine and neighbouring MSs, as well as between Ukraine and Moldova, were organised in July 2020. At the Hungarian border, the capacities are offered at the RBP booking platform, while at the Polish border, at the GSA one. What is more, all these cross-border capacities are now managed as VIPs[179]. All the products offered relate to unbundled capacity. Most bookings relate to monthly firm or interruptible capacity so far, whereas products for longer duration have been allocated only in few cases.

273 Finally, the Ukrainian TSO announced some maintenance works at the Budince IP, for a duration of several weeks in the summer of 2020. This reduced the firm capacity from Slovakia to Ukraine by about 40%, prompting shippers to rebook part of these capacities at Velke Kapusany in the reverse direction. The repairs prompted divergent views between the adjacent TSOs about how to better manage the firm capacity at the larger Velke Kapushany IP, which flows gas from Ukraine into Slovakia. The situation also revealed some regulatory discrepancies. While both jurisdictions are bound to apply the same EU acquis, their current regulatory frameworks partly diverge, a.o. due to the voluntary implementation of the network codes at the IPs of EU MSs with CPs. The Slovakian and Ukrainian TSOs and NRAs engaged in an informal dialogue facilitated by ACER and EnC to gather views on improving capacity availability at the border, and ACER and the Energy Community Secretariat have run a consultation on the broader issue of improving capacity availability at IPs between MSs and CPs to get stakeholders' views on the issue.

5.2 TAR NC effects

274 This section first summarises the main provisions of the Tariff Network Code and infers possible market effects related to the code's implementation. It includes an overview of the levels of the tariff multipliers applied to short-term capacity products, offering some considerations about their market effects. The section concludes with an analysis of the relative position of price spreads and short-term transportation tariffs for selected hub pairs.

275 While the focus of Section 5.1 is on the trends at and links between IP capacity bookings and cross-border gas flows, transportation tariffs are a crucial factor in shaping both. This is because IPs' tariffs set the cost for the right to transport gas between gas market areas, unlike in the IEM where electricity flows are implicitly allocated following market coupling results. Furthermore, MSs' domestic production covers, on average, less than 20% of EU's gas demand. EU gas supplies are principally imported from external producers and then transported across zones, incurring shipping costs that are inherent in the final gas price formation[180].

5.2.1 New RPMs effects on cross-border tariff levels and prices

276 The TAR NC established a number of criteria for setting gas transportation tariffs in a more transparent, cost-reflective and harmonised manner. The code's transparency provisions, which have been gradually implemented since 2017, have assisted to better reproduce and forecast tariffs, hence enabling network users to build their capacity portfolios with more certainty[181].

277 In addition to enhancing transparency, the TAR NC has compelled MSs to revise and make fully compatible with the code's requirements the reference price methodologies (RPMs) that are used to set the tariffs at the individual gas networks. The new RPMs must charge all gas network users in a cost reflective manner, avoiding undue cross-subsidation. Since 2019, the Agency has gradually examined each of the newly proposed RPMs, to evaluate if, amongst other things, they distort cross-border gas trade or include elements of cross-subsidisation.

179 Between Ukraine and Hungary, merging the previous separated IPs of Beregovo and Beregdaróc and in the case of the Polish-Ukrainian border, merging Hermanowize and Drozdowicze.

180 Usually, the gas supply prices in an entry/exit zone are set by summing the gas commodity cost to the transportation costs, even if in some cases transport tariffs are not fully included in the final gas supply prices. Transportation cost can represent from 3% to 10% of final gas price depending on the route length and tariffs.

181 The code requires publishing the reserve price of capacity products before the organisation of capacity auctions. Before the TAR NC implementation, the yearly capacity tariffs and the short-term multipliers were published in various MSs only after the yearly transportation capacity auctions were carried out.

278 The implementation of the new RPMs, which started at the end of 2019 and should gradually conclude by the end of 2022[182], is linked to relevant changes in the tariff levels of selected gas systems. The changes have resulted either from the use of a distinct tariff methodology and/or different cost-drivers, a modified entry-exit split[183] or from the implementation of adjustments[184]. Besides, the values of the regulatory asset bases and/or the demand scenarios considered in the tariff period may have varied, altering the revenue recovery targeted for each individual point and hence its tariff level. All the cross-border tariffs applicable at European IPs for the year 2021 are shown in Figure vi of Annex 1.

279 The MMR 2019 outlined an overview of the new RPMs following the TAR NC implementation. Complementarily, the Report gauged the variations that will occur at the tariffs of cross-border IPs and domestic exit points[185]. While in a slight majority of cases, the new RPMs – together with the RAB and new demand factors – led to increases in the tariffs of the exit side of cross-border IPs as well as at domestic exit points, the situation is country specific.

280 For example, the IPs exit-side's tariffs from Germany into the French and Swiss market zones have risen by two-digits on average since January 2020, once the new RPM was implemented. The tariffs on the IP exit-side from Poland and the Netherlands into Germany have shown similar increases since then. In the case of Germany, most IP entry-side' tariffs have also increased, whereas the country's domestic exits have slightly fallen (on average -6%). Two-digit domestic exit tariff' decreases (around -20%) have occurred in Greece and in Portugal since January 2020 and October 2019 respectively[186] and will occur in Austria and Spain from 2021, once their new RPMs get implemented.

281 Higher cross-border exit tariffs generally tend to increase the transportation costs for exporting gas, either acquired in or transited across the VTP. Conversely, lower IPs entry-side tariffs tend to incentivise accessing a MS's VTPs. The choice of lowering entry tariffs tends to seek for an overall lower hub price formation and/or the promotion of gas transits. The latter purpose is more notable where supply-route competition exists between nearby gas systems. Both effects can be fair outcomes of the newly adopted RPMs as long as the TAR NC principles are maintained, including the use of consistent cost-drivers.

282 For example, the IP entry-side's tariffs to access Italy or Portugal, as also will apply to Austria next year, have all decreased by more than 20% promoting lower hub sourcing costs. Also with this aftermath as well as to further promote gas transits, the IP entry-side's tariffs in Hungary have significantly dropped since 2019 (about -20%, although in this case before the TAR NC implementation, see case study in section 4.3.1) as the tariffs in Slovenia and Slovakia will do from 2022 onwards.

283 Assessing the impact of IP tariff changes on the hubs' price levels, IPs utilisation and the capacity booking strategies of network users is complex. This difficulty originates from a combination of factors:

- While all the changes of transport tariffs' are relevant as they can rebalance the supply competition among gas transport routes[187], the changes in the marginal supply routes are of particular significance. This is because the gas flown across these routes tends to discipline price formation at the hub.
- Complementarily, individual IPs perform dissimilar supply roles as discussed in the section above, which range from baseload gas sourcing to arbitraging hub price differentials. The effects of the IP tariffs' variations on utilisation will be more marked on the latter than on the former.

182 The new RPMs, in accordance with TAR NC principles, shall enter into force for the first new tariff-period after May 2019.

183 The split determines the relative weight of revenue recovery taking place at entries or exits. It must make use of specific cost drivers, aiming to safeguard the cost-reflectivity principle. 50/50 is seen as the theoretical benchmark in the NC and has turned in the most common practice.

184 While The TAR NC establishes that the same RPM should be applied to all network points in an entry-exit zone, considering specific cost drivers, it offers some discretion to pursue a better operation of the network. Adjustments are allowed, for example, to stimulate pipeline to pipeline competition. The adjustments are equalisation – i.e. removing tariff differentials to some or all points within a homogeneous group of points to reduce their variance –, rescaling – i.e. adjusting all entry and/or all exit points tariffs by multiplying their values by a constant (or by adding a constant factor) - and benchmarking – i.e. adjusting the tariff at a given entry or exit point so that the resulting values meet the competitive level of references prices.

185 See MMR 2019 Figure 36 and Figure 37, data also accessible at the MMR data portal CHEST. The postage-stamp has been the prevailing methodology, followed by capacity weighted distance (CWD).

186 In Portugal, alongside the implementation of the new RPM, the total allowed revenues decreased by 21.2% in the gas year 2019-2020.

187 Therefore, the tariff changes in one route need to be contrasted against the use of other supply options.

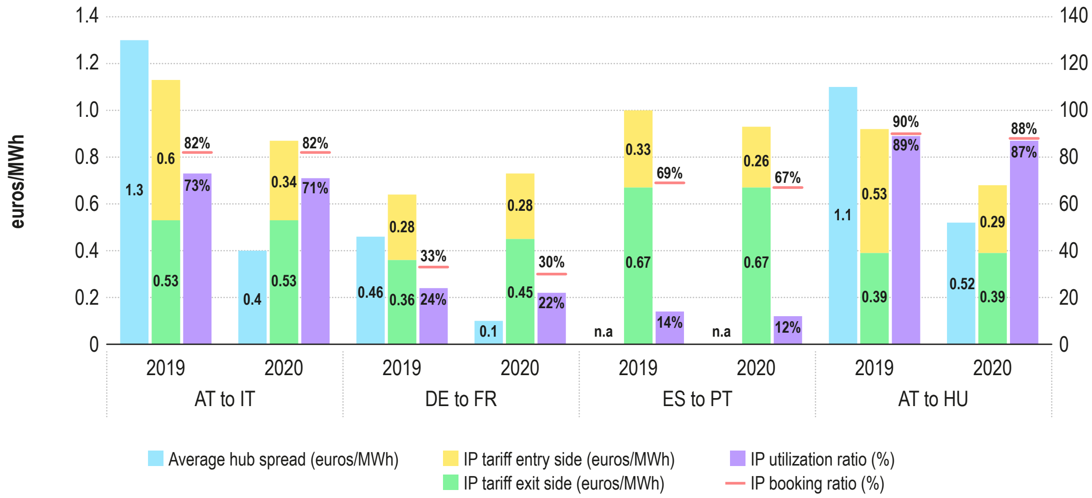
- In most gas systems, floating tariffs are applied[188]. However, some systems still maintain fixed tariff systems (e.g. Slovakia, Czechia). Regarding the latter, the transport cost of existing contracts may not change after the new RPMs get implemented.

- The implementation calendar of the new RPMs is gradual. By the end of 2020, just half of the MSs had implemented the new methodologies[189].

- Finally, the level of tariff multipliers can partly offset the tariff variations, as will be discussed in the subsection below.

284 Furthermore, the market impact due the IP tariffs' changes in 2020 is to be assessed in the specific market context described in Chapter 2. While tariff variations have been of distinct magnitude, the level of price convergence between market areas was overall reinforced YoY. Convergence has in fact increased between markets where tariffs rose, for example the case of France and Germany, as shown in Figure 39. The figure shows the evolution of the tariffs between selected market areas where new RPMs have been implemented and compares them against the hub price spreads and the IPs booking and utilisation levels.

Figure 39: Overview of the evolution of transportation tariffs, price spreads and IP booking and utilization ratios at selected hub pairs following new RPMs implementation – 2019 and 2020



Source: ACER based on ENTSOG TP and ICIS Heren.

Note: In Germany, Italy and Portugal the new RPM tariffs were in January 2020 and in Portugal in October 2019. In Hungary a tariff revision took place at the end of 2019 although the new RPM haven't been implemented yet. In France the new RPM was implemented on April 2020, but the cross-border IP tariffs will be updated on October 2020, to coincide with the CAM auction calendar. In Austria and Spain the new RPMs will enter into force in January and September 2021 respectively. The price convergence refers to the month-ahead product except for the Austrian-Hungary example that refers to the day-ahead hub product.

285 Figure 40 shows how the price convergence between the Italian and the Austrian hubs has significantly improved YoY. Convergence has been assisted by the tariff decreases at the Italian entry-side since January 2020. Yet, the utilisation of the Austrian-Italian IP corridor was lower in 2020 than in 2019. Moreover, the booking and use ratios of the Spanish-Portuguese VIP were lower in 2020, despite the fact that the tariff at the Portuguese IP entry-side has decreased by 20% with the newly implemented RPM (a similar 20% drop will occur from October 2021 on the Spanish exit-side). In the case of the interconnection between Austria and Hungary, the utilisation and booking ratios have been maintained at rather high levels. The tariff decrease at the Hungarian entry side is deemed to have assisted price convergence, as the case study in Section 4.3.1 has discussed.

188 Floating tariffs entail that the reserve price is derived using the RPM for every tariff period, while fixed tariffs are maintained over multiple tariff periods possibly adjusted to annual inflation.

189 See a detailed implementation calendar at the Agency Report on the application of reference price methodologies in Member States.

286 In addition to the plausible effects caused by tariff revisions, the lower utilization ratios in all the IPs shown in Figure 39 are explained by a higher reliance on LNG imports and/or UGS withdrawals throughout 2020. Besides, amplified supply options may have also contributed; e.g. larger flows into Hungary from Slovakia or Romania YoY or shippers discounting that TAP flows will reach Italy from 2021. In addition, the lowered demand induced by COVID-19 also reduced import needs and put downward pressure on prices. The latter overall contributed to enhance hub price convergence, as discussed in Section 2.1.3.

287 Future editions of the MMR will continue to analyse the tariff revision effects for more market areas, once the new RPMs get more extensively implemented.

5.2.2 Effects of short-term tariff multipliers

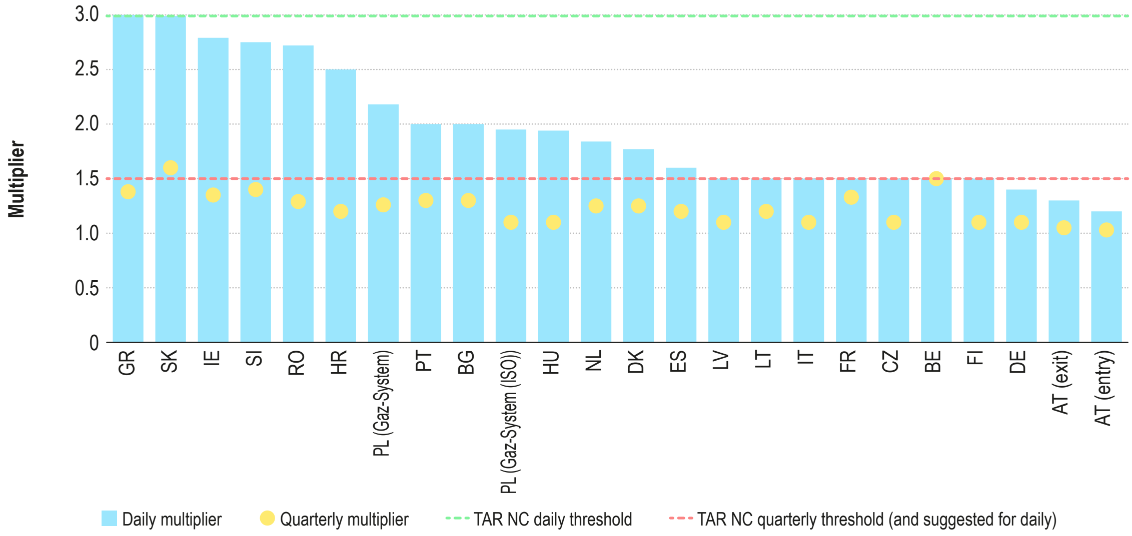
288 Another relevant element in the scope of the TAR NC that has an impact on hub price convergence is the level of the tariff multipliers applied to the capacity products of shorter-term duration.

289 The TAR NC sets a maximum cap of 3 for the multipliers applicable at shortest-term capacity products[190] (daily and within-day) and a limit of 1.5 for quarterly and monthly ones. In addition, the TAR NC recommends that the exact same multiplier is applied to all the entry or exit IP sides of a market area. The code states that the multiplier cap for daily and within-day products shall be reduced to 1.5 in 2023 if ACER issued a recommendation in this direction, after having assessed the potential impacts that this limitation could cause on shippers' booking behaviour, hub price convergence and revenue recovery.

290 At the end of 2020, ACER ran a public consultation to evaluate the gas stakeholders' positions on the subject. While ACER decided not to prescribe a cap of 1.5 for short-term multipliers in terms of the Article 13 of the TAR NC, ACER committed to issuing a specific Recommendation on the subject by mid-2021 that clarifies the topic in more detail[191].

291 Figure 40 summarises the level of the tariff multipliers for the day-ahead and quarterly products proposed in the new RPMs. It shows that in all markets, multiplier values of a maximum of 3 have been set for daily products (in some markets they reached more than 5 before the TAR NC). However, in various instances daily multipliers keep exceeding the 1.5 threshold. Overall, price convergence tends to worsen between markets that apply higher short-term multipliers, although the absolute level of tariffs and other competition and supply diversification aspects are equally relevant.

Figure 40: Overview of the daily and quarterly capacity products' multipliers set in the new RPMs following TAR NC implementation



Source: ACER based on NRAs and TSOs.

Note: The entry into force of the new multipliers is linked to the new RPMs implementation date, which ranges from the end of 2019 to the end of 2022 per individual MS.

190 In duly justified cases, they may be less than 1, but higher than 0, or higher than 3.

191 The public consultation led to an overall identification of lower multipliers as a theoretically relevant factor to enhance hubs' price convergence. However, equally important to the multipliers were the absolute reference tariffs. As the analyses and position have not been able to mark out mathematically the specific effects' of tariff multipliers, the Agency called for caution when setting a 1.5. cap for short-term multipliers.

292 The decision about the most effective level of short-term tariff multipliers is multidimensional and relates to the distinct characteristics of the markets and of individual IPs.

293 Multipliers can affect the interconnectors' utilisation, the hub price convergence levels and the revenue recovery in various ways, creating equilibriums between network users' capacity profiling strategies and revenue recovery consolidation aspects.

294 Transportation tariffs tend to add up to the cost of the commodity to set the final gas price levels at individual markets. In this respect, relatively high multipliers applied to newly contracted short-term capacity would result in higher tariff levels and hub spreads for shorter-term products. In addition, they could deter network users from dynamically booking short-term capacities to arbitrage hub positions or for balancing purposes[192].

295 On the other hand, relatively high multipliers provide an extra incentive to acquire yearly bookings. That approach rewards the shippers that can guarantee longer capacity commitments, which is positive to secure TSOs' revenue recovery.

296 As such, for NRAs setting multipliers relates to an equilibrium between ensuring revenue recovery, promoting cross-border trade and, last but not least, maintaining cost-reflectivity. In essence, this balance is based on seeking the optimal share of revenue to be recovered from users holding short-term or long-term capacity products. Low short-term multipliers can be considered as a way to foster competition and to incentivise more dynamic booking strategies. However, too low multipliers can reduce the revenue recovery on short term products, leading to an increase in yearly capacity tariffs which in turn can disincentive long-term bookings.

297 For the individual shippers and traders, once the multipliers have been set, the profiling of capacity products turns eventually into a cost optimization issue. They take their decision in view of their market strategies but also the dissimilar supply roles of the IPs that they book. For example, theoretically, a short-term tariff multiplier of two implies that a shipper that booked a yearly capacity product and used only half of its total capacity rights would have a similar final total expenditure as the shipper that covered its capacity needs fully matching its flow needs with day-ahead products. For the former, the extra capacity could serve the over-contracted shipper to perform price arbitrage – if considering the excess of capacity as a sunk cost – while the latter shipper could get better flexibility to optimise its portfolio, even with a potential higher risk to secure capacity.

298 Therefore, in practice gas shippers use different booking strategies taking into account their supply and demand portfolios, the market dynamics and the tariffs of distinct capacity products. For example, shippers tend to secure a certain minimum amount of capacity with yearly capacity products while they may cover the seasonal and short-term variations with short-term ones. If the shipper needs to secure capacity at an IP that is core to maintain a baseload supply it will opt for longer duration products. If it uses the IP to optimise price arbitrage positions it will book shorter-term one more frequently and as such the impact of the multipliers will be higher.

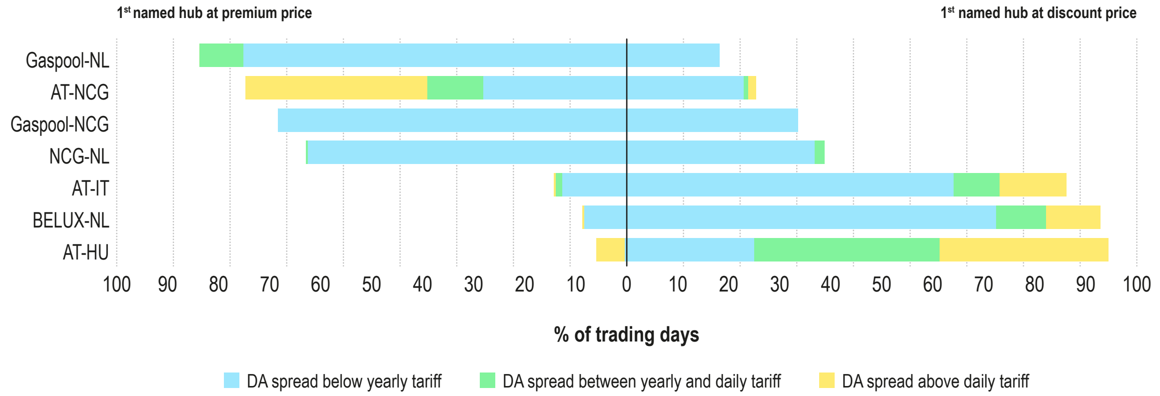
5.2.3 Impact of gas transportation tariffs on hub price spreads

299 Cross-border transportation tariffs represent an important reference for gas prices and hub price spreads formation. Between liquid, neighbouring hubs with sufficient available cross-border capacity, a price difference close to or above the tariff in the same timeframe represents a market arbitrage opportunity that would trigger shippers interest to book transportation capacity.

300 Figure 41 shows the spot price spread levels relative to the transportation tariffs of yearly and daily capacity products for a selection of adjacent hub pairs. It reveals that between most hubs, spot price spreads are regularly below both daily transportation tariffs and yearly transportation tariffs, especially between NWE hubs.

192 For example, in Central Europe, the relative high day-ahead tariff multipliers could have partly deterred the attractiveness of using the EU gas stock in Ukraine (attracted by favourable conditions, see Section 2.2.4) to further arbitrage spot prices.

Figure 41: Day-ahead price spreads relative to reserve daily and yearly transportation tariffs for a selection of neighbouring EU hubs – 2020 – % of trading days within given price spread range



Source: ACER calculation based on ICIS and hub operators' data for prices and ENTSOG TP for transportation tariffs.

301 An important reason that may lead to the difference in the price of gas exceeding transportation tariffs between gas markets is unavailability of transportation capacity due to either physical or contractual congestion. This is the situation between the German NCG and the Austrian VTP hub or between the Austrian and Hungarian hubs for a significant number of days (see the yellow segment of the column). Other factors that may decouple hub price formation refer to possible barriers to market entry or low hub liquidity and competition.

302 As outlined in Section 2.1.4, the price convergence between neighbouring hubs notably improved in 2020 in comparison to 2019. As a result, across 2020, there were also fewer instances of hub price spreads in excess of connecting transportation capacity tariffs. As mentioned, the overall lower demand and the high levels of gas in storage facilities minimised the need for prices to rise over tariffs to attract additional flows from neighbouring markets.

5.3 BAL NC effects

303 For safety and operational reasons, gas transmission networks must be kept in balance. This entails that the volume of gas withdrawn from the network match that injected into it. This is required in order to keep the network at the correct pressure. However, unlike in electricity networks, where load and supply need to be continuously balanced to prevent a critical change in frequency which could cause an outage, gas networks can handle moderate differences between inputs and offtakes for a limited amount of time[193].

304 Imbalances occur when, in a given time period[194], gas network users collectively supply either insufficient or excess gas volume relative to that withdrawn from the system (be it for consumption, storage, or transport to adjacent systems). Similarly, a network user is out of balance if his portfolio is out of balance i.e. if his withdrawals from the system (towards its customers at the distribution level, to CCGT, etc.) are either greater or below what he has injected into the system.

305 The BAL NC sets out rules for creating a market-based balancing regime by, amongst other things: giving the main balancing responsibility to individual network users; requiring that TSOs procure products for balancing from the market; and by enabling network users to trade imbalances on a non-discriminatory basis. The desired outcome is that network users are primarily responsible for balancing both their position and, as a consequence, for the overall system position, leaving the TSOs with a small, but crucial, residual balancing role. Before the BAL NC came into force, there were a variety of different gas balancing systems in the EU, with some systems already applying market-based regimes, and others giving neither the tools nor the opportunity to network users to contribute to system balance.

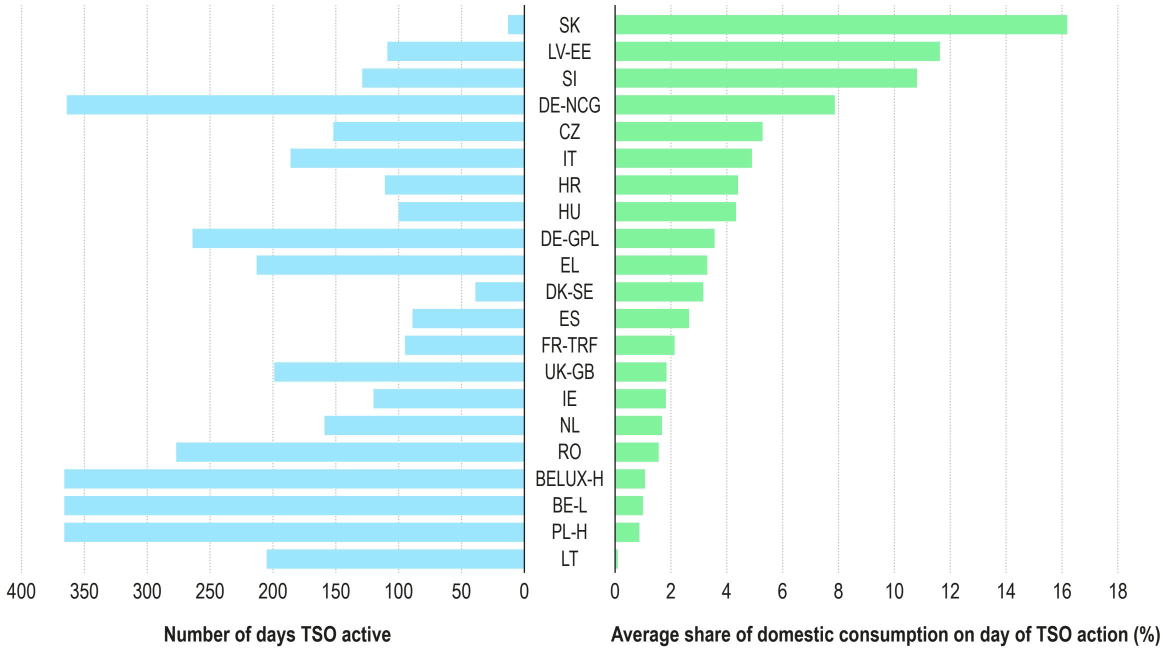
193 This flexibility, sometimes called linepack flexibility, depends on the physical characteristics of a network which determines how large and for how long, discrepancies between input and output can occur without compromising neither the safety nor the efficient operation of the network. Linepack is the amount of gas within the system at any time.

194 The balancing network code has established the gas day as the relevant time period.

306 There is noteworthy variation between market zones in terms of how often TSOs needed to trigger balancing actions. This is illustrated in Figure 42 that shows the number of days TSOs took balancing actions and the average size of those interventions relative to domestic demand on the day the balancing action was taken. For example, in GY 2019/2020, while the Slovak TSO only actively intervened to balance the system on a limited number of days, the TSOs and market area managers of the NCG, PL-H, BELUX-H and BE-L systems[195] triggered balancing actions on every day[196] of the 2019/2020 gas year.

307 However, while informative about the variation in the TSOs residual balancing role across different balancing systems, such an illustration is not conclusive. The extent to which a balancing system is facilitating the development of gas wholesale market liquidity is dependant, amongst other things, on the incentives and tools (e.g. accurate and timely information about the system's and their own balance) presented to network users. For instance, the use of flexibility services and arrangements that allow for ex-post trading of imbalances[197] diminishes network users' incentives to take action to balance their positions, including by trading at the hub, thereby reducing liquidity.

Figure 42: Number of days and average relative magnitude of TSO balancing intervention – selected balancing zones – GY 2019/2020



Source: ACER calculation based on TSO and MAM data compiled by ENTSOG.

Note: The average TSOs balancing action volume is calculated relative to domestic demand for days when a balancing action was taken.

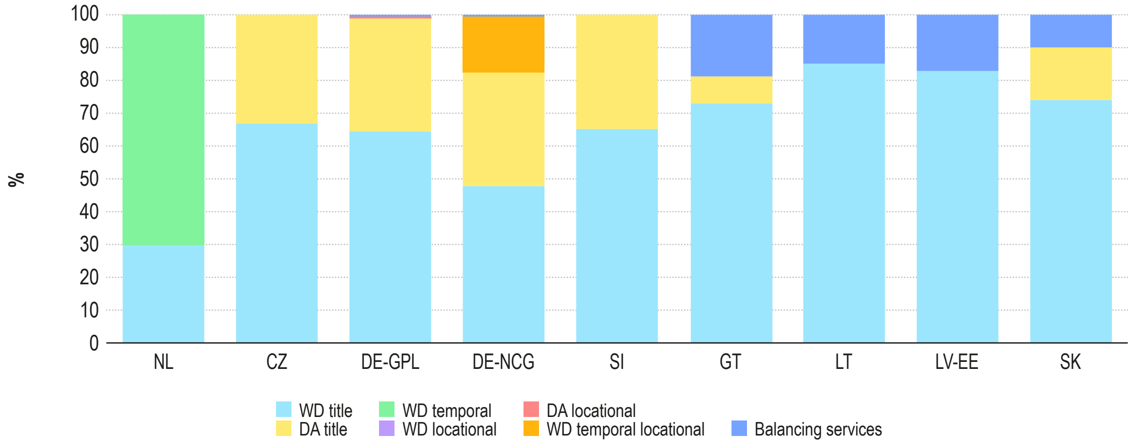
195 For instance, in the case of the Belux-H and Belux-L zone, such outcomes are a consequence of the balancing regime design. The imbalance associated with the aggregated commercial position arising on one day is corrected early in the following day by a balancing action to offset the previous days' imbalance. Similarly in the case of PL-H, the balancing policy applied seeks to remedy the aggregate commercial balance of network users from the previous day and so one action per day is taken in the within day title market to offset the previous day's imbalance.

196 According to ACER's fifth Balancing Report: "Several zones indicate that balancing actions are taken on every day. Whilst this should not necessarily be automatically considered to be a poor outcome such instances warrant consideration. Actions on every day may be a natural consequence of the regime design rather than as an absolute requirement to take actions because of the state of the system. Additionally TSO actions taken every day have a merit in so far as they generate market based transactions that might help ensure that the cashout prices are set by reference to a value associated with short term flexibility value on the day."

197 For instance, flexibility services in France and the Czech Republic, ex-post imbalance trading in Lithuania. Since the BAL NC establishes the gas day as the relevant balancing interval, ex-post imbalance trade is not formally compliant.

308 In order to stimulate the functioning of the wholesale market, the BAL NC requires TSOs to procure volumes needed for balancing purposes according to a merit order that favours trading platforms above balancing platforms and balancing services; and title products above temporal and locational products. This should enhance hub liquidity and lead to a fairer formation of imbalance prices charges. The within-day title product offered on trading platforms is placed highest in the merit order according to the BAL NC, and the majority of TSOs were able to procure all necessary balancing volumes using such a product in the monitored period. However, some TSOs used also other products and services for their balancing actions as Figure 43 shows.

Figure 43: Breakdown of TSOs balancing volumes according to products used – selected balancing zones – GY 2019/2020



Source: ACER calculation based on TSO and MAM data compiled by ENTSOG.

309 Even among the TSOs that had not exclusively used the WD title product as a source of balancing volumes, the WD title product accounted for the majority of TSOs procured balancing volumes, with the exception of the Dutch market area and the German NCG. The Dutch zone stood out for the TSO's reliance on the WD temporal product as the main source of procuring balancing volumes, which can be explained by the specific balancing regime that focuses on near continuous rather than end of the day system balance.

5.3.1 Assessment of the impacts of NCs on gas-fired power plants operation and possible regulatory options

310 Gas-fired power plant operators are distinctive participants in the EU internal energy market, because they operate in both its gas and electricity segments. CCGTs operators provide flexible power supply and at the same time they act as price-responsive gas consumers.

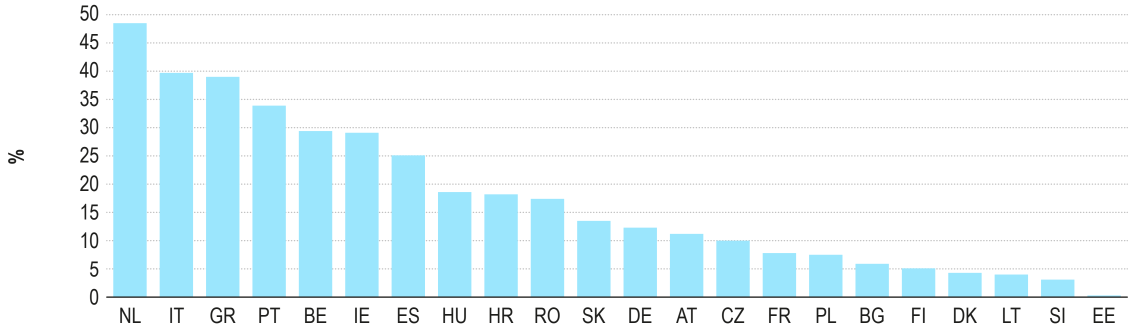
311 As the operation of CCGTs is inherently difficult to forecast, but also because the gas-fired plants can be ramped-up faster than other power generation technologies, CCGTs operation tends to be short-term oriented. In this regard, the liquidity expansion of EU spot gas markets in recent years, a goal supported by the gas NCs, has assisted their more efficient operation.

312 In the opinion of consulted market participants[198], gas NCs have addressed to an extent some past risks associated with the short-term operation of CCGTs. For instance, the neutrality rules of the BAL NC and the establishment of a quota for short-term IP capacity in the CAM NC are seen as positive achievements.

313 The benefits that the implementation of NCs provisions have rendered on the electricity side are however more challenging to assess. A higher impact in terms of lower electricity clearing prices can be expected where and when gas fired power plants more frequently set the marginal electricity price. Figure 44 infers the significance of gas-fired generation across the power systems of MSs.

198 ACER interviewed various CCGT operators and energy traders to seek views on the impacts of gas NCs on gas-fired power plants operation.

Figure 44: Median share of electricity load fulfilled by gas-fired power generation – 2020 – % of total power generation in the national system



Source: ACER based on ENTSO-E.

314 The general drive to decarbonise the EU economy and the ESI ambitions will greatly impact the operation of gas and electricity systems in the years to come. Ample phase-outs of coal-fired power plants are foreseen in parallel to a massive rise in RES-E penetration. Furthermore, some parts of that new RES-E are foreseen to produce renewable gases. This developments will pose challenges that will make it necessary to reconsider the interaction between gas and electricity markets.

315 Importantly, the growth in intermittent RES-E generation is expected to increase the complexity of ensuring the adequacy between net available generation and the net load levels in EU power systems. This challenge has been identified by both NRAs and TSOs[199]. Gas fired power plants are called to play an important role in balancing the intermittency of RES-E, together with other flexibility tools such as demand side response and storage.

316 Given the coming challenges, it is important to assess if the current regulatory framework applied to gas-fired power plants will be fit-for-purpose. Adjusting the regulation that will govern the integration of gas and electricity markets' will require an alignment of some of the regulatory provisions that govern the access to infrastructure. However, the physical differences between the two sectors should also be taken into consideration.

317 Gas infrastructure offers greater flexibility than electricity infrastructure due to the more ample gas storage capacities (in particular for seasonal storage) and the availability of a larger gas network linepack. Gas regulation should hence promote the use of this larger flexibility to also contribute to the balancing of the electricity system. However, on the electricity side, the regulation has to carefully consider the physical constraints.

318 Gas infrastructure costs consist predominantly of capex. For that reason, TSOs tend to collect most of their revenue through capacity tariffs and tend to promote the booking of longer-term capacity products. However, gas-fired power operators are inherently prone to book short-term capacities because for them it is difficult to predict the plants' load factors over long periods. Some MSs have implemented Capacity Remuneration Mechanisms (CRMs) – a temporary measure introduced to remunerate electricity capacity resources (e.g. generators, demand-response or storage units) for security of supply services. CRMs can be introduced or maintained only if a resource adequacy concern has been identified that a market-based solution cannot address, to the extent and duration necessary to solve the problem[200]. In the specific case of gas-fired power plants, CRMs are in some instances necessary to reconcile the gap between the uncertainty and variability of their operation and the fixed costs they incur, including costs related to gas network capacities.

199 See for example the ACER Decision on the Methodology for the European resource adequacy assessment and the ENTSO-E revision of its existing adequacy methodology.

200 See the latest MMR Electricity Wholesale Volume for more details about CRMs.

Possible regulatory options to increase the flexibility of gas-fired electricity generation

319 Hub liquidity in a number of EU gas markets remains limited. Furthermore, while spot markets' liquidity is generally higher compared with forward markets' liquidity, transactions in the former are generally focused on the day-ahead product (see section 4.2.3 for an assessment of liquidity of EU gas hubs). Bar a few exceptions, within-day products liquidity remains limited at EU gas hubs. This situation hampers a more efficient operation of gas-fired power plants, whose consumptions are difficult to predict even day-ahead.

320 In those markets with more limited spot liquidity, operators of gas fired power plants have fewer options to back their positions, which can create larger imbalance charges. This setting tends to particularly penalise smaller players with narrower transmission capacities and consumers' portfolios. NRAs should therefore as a rule seek to expand the within-day liquidity of gas markets.

321 Furthermore, gas-fired power plants are better operated when they can make the use of the supply flexibilities offered by the gas system. For that reason, NRAs and TSOs should favour daily balancing regimes that limit as much as possible any unnecessary constraints. For instance, the implementation of within-day balancing obligations should strictly reflect an actual physical constraint that cannot be neglected to ensure the integrity of the network (e.g. a limited linepack).

322 In that regard, and to the extent possible, NRAs and TSOs should assess the feasibility to choose a market-based approach instead of using within-day balancing obligations. TSOs can for instance trade temporal or locational products (as stated in the article 9 of the BAL NC) to manage their linepack. The market liquidity for such products should obviously have to be assessed to avoid any abuse of market power.

323 As it is difficult to predict the load factor of gas-fired power plants, NRAs and TSOs should evaluate the possibility of further increasing the flexibility of the capacity allocation mechanisms in view of allowing shorter-term bookings. This applies both at domestic delivery points and at cross-border IPs.

324 Complementarily, CCGT operators will book short-term capacity products only if tariffs are competitive enough. NRAs could for instance assess the possibility to adjust the tariffs applied to short-term delivery capacities at the connections with gas-fired power plants, as long as this is done on a non-discriminatory basis – the same set of multipliers applied at IPs could be used. Moreover, CCGT operators should benefit from a tariff discount if their delivery capacities are not firm and they should not contribute to gas security of supply charges if they can be interrupted.

325 NRAs and ACER should submit these considerations to a careful CBA, as they could have some adverse impacts. For example, more dynamic gas fired power plants' load factors could increase the balancing costs for TSOs (e.g. by making TSOs' linepack management more complex) and ultimately network users. Besides, granting the possibility to gas fired power plant operators to further profile their capacities could induce rises in the tariffs of other capacity products (more profiled and optimised bookings would reduce the total amount of booked capacity, while the TSOs' costs would remain stable).

5.4 Interoperability NC effects

326 The interoperability network code (INT NC)[201] enables the harmonisation of the operational and data-exchange procedures that assist TSOs to manage gas systems in a coordinated and effective manner. The code has been fundamental for the IGM construction. By addressing aspects such as gas quality, odourisation, nomination units and several other technical features it has facilitated unrestricted gas flows and efficient cross-border trading in the EU.

327 The INT NC provisions may have to be reviewed as the EU gas network prepares to accommodate the integration of increasing quantities of low-carbon gases, such as biomethane and hydrogen admixtures into natural gas. The ability to integrate these gases without hampering trade will be determined by the technical features as well as the procedural rules that the INT NC oversees.

201 Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules.

328 While the current gas network and most end-use appliances can accommodate biomethane without major technical adjustments, the readiness of the current gas network to integrate hydrogen admixtures is more under discussion, given more divergent physical properties of both. The calorific value of hydrogen is about three times higher than of natural gas expressed in MJ per kg (i.e. 140 MJ/kg for hydrogen and 55 MJ/kg for methane), while the density of hydrogen is nine times lower expressed in kg per m^3 (i.e. 0.09 kg/m^3 for hydrogen vs 0.8 kg/m^3 for methane). These combined features entail that the energy density of hydrogen – measured in kWh/m^3 - is three times lower for hydrogen than for methane (3 kWh/m^3 vs 11 kWh/m^3 for methane). However, at the operational pressures of gas network, the volumetric flow of hydrogen is around three times larger than the natural gas flow rate. These combined features entail that a quite similar energy quantity could be transported. With respect to combustion at final consumption points, the Wobbe Indexes of both gas and hydrogen are as such rather closely assimilated after factoring their specific gravities[202]. This entails that both fuels (and their mixes) could be in the range of being substitutable. However, hydrogen has a higher flammability range and a faster burning velocity, so most end-use appliances would need some adaptation[203].

329 The different properties of hydrogen and gas imply that the existing gas networks and end-use equipment can in general only accept hydrogen up to a certain limit today. In fact, over a certain threshold of hydrogen admixture, the cost and technical challenges of network adaptation would result in increased network costs. A reference of 10% admixture is commonly used204; however, the exact quantity can vary among and within MSs in accordance to the technical features of their networks and final end-user industries and appliances.

330 ACER has recently published a report[205] about the current possibilities for admixing hydrogen at gas transmission networks, based on information proved by NRAs. In most MSs (65%), TSOs do not accept the injection of hydrogen into the transport grid, while Austria, France, Germany, Latvia, the Slovak Republic, Spain and Sweden accept it under certain conditions and thresholds. Figure 45 shows the hydrogen admixture maximum limits, subject to technical concerns clarified in the dedicated ACER report.

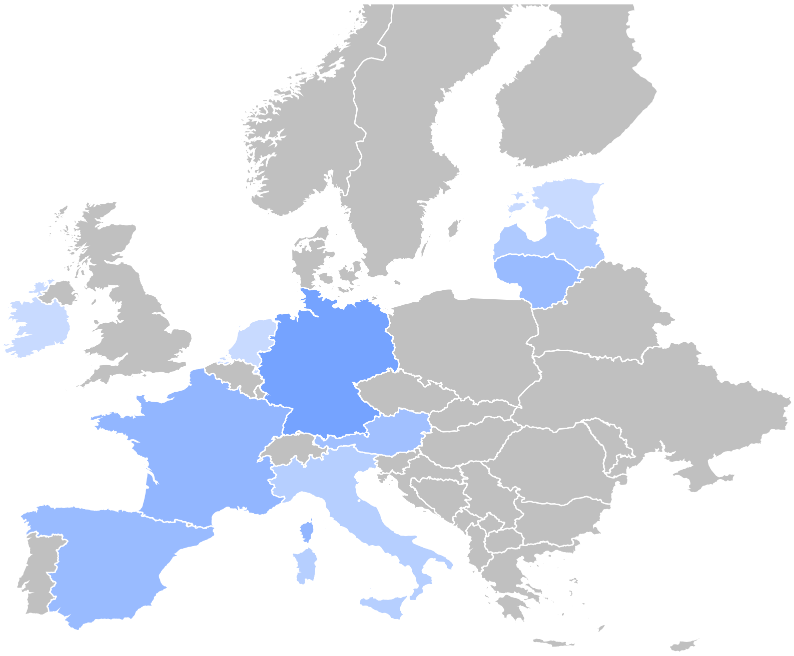
202 The Wobbe Index is the representation of the heating value of the gas arriving from the line to the burner, which is proportional to its flow volume per time. Complementarily, the flow velocity is affected by specific gravity of each of the gases, circa nine times lower for hydrogen. As a result, natural gas, hydrogen and their blends account for rather compatible Wobbe Index values.

203 The industry and end-user associations are calling for clarifications to make equipment hydrogen ready. This applies for example to gas turbines ready for conversion into hydrogen or industrial and domestic boilers. Some consumers are more sensitive to hydrogen quality impacts than others; some large industrial sectors vocally underlie the risk associated to fluctuating gas qualities.

204 See Marcogaz overview of test and regulatory limits for hydrogen admission into existing gas network.

205 See ACER Report on Hydrogen, Biomethane and Related Network Adaptations

Figure 45: Hydrogen acceptance in MSs gas systems and blending thresholds – %



Source: ACER based on NRAs and TSOs input.

Note: The blending thresholds limits apply to some sections under technical constraints; e.g. no sensitive customer connected. See detailed considerations on the ACER report.

331 A more harmonised technical framework for carbon neutral gases needs to be developed. This technical framework will need to be applicable both at national and European level. Its primary aim shall be that the new injections neither limit trade nor unduly impact on final consumers, for example in aspects such as the suitability of their appliances. The discussion involves the interactions between distribution and transmission network. Distribution segments accommodating decentralised production and serving separately associated demand may be subject to ad-hoc solutions206.

332 The gas Industry and relevant standardisation associations are holding discussions on the possible technical standards to apply to low-carbon gas production and hydrogen handling. They take place for example at the Prime Movers Technical Forum207. The exercise is to some extent similar to the past discussions about the gas quality of conventional natural gas coming from dissimilar supply origins.

333 The European Committee for Standardisation (CEN) received a mandate to set the acceptable ranges of gas parameters at EU gas systems, which will include carbon neutral gases. The INT NC requests individual national systems to comply with certain gas quality ranges, while it leaves it to adjacent TSOs solve potential conflict situations of distinct qualities via technical cooperation208, which also applies to gas odourising practices. More precise technical decisions are needed with the overarching aim of keep guarantying market integration – that also assists SoS – while accommodating carbon neutral gas flows.

206 While widespread standardised criteria guarantee a broader acceptance of low carbon gases and gives security to final users, there seem to be some trade-offs with more flexible specific ad-hoc solution, which could turn more cost-effective. Some degree of CBAs are considered to evaluate decisions.

207 The Prime Movers technical forum brings together industry representatives as well as regulators and consumer association to seek consensus on neutral gases quality management principles.

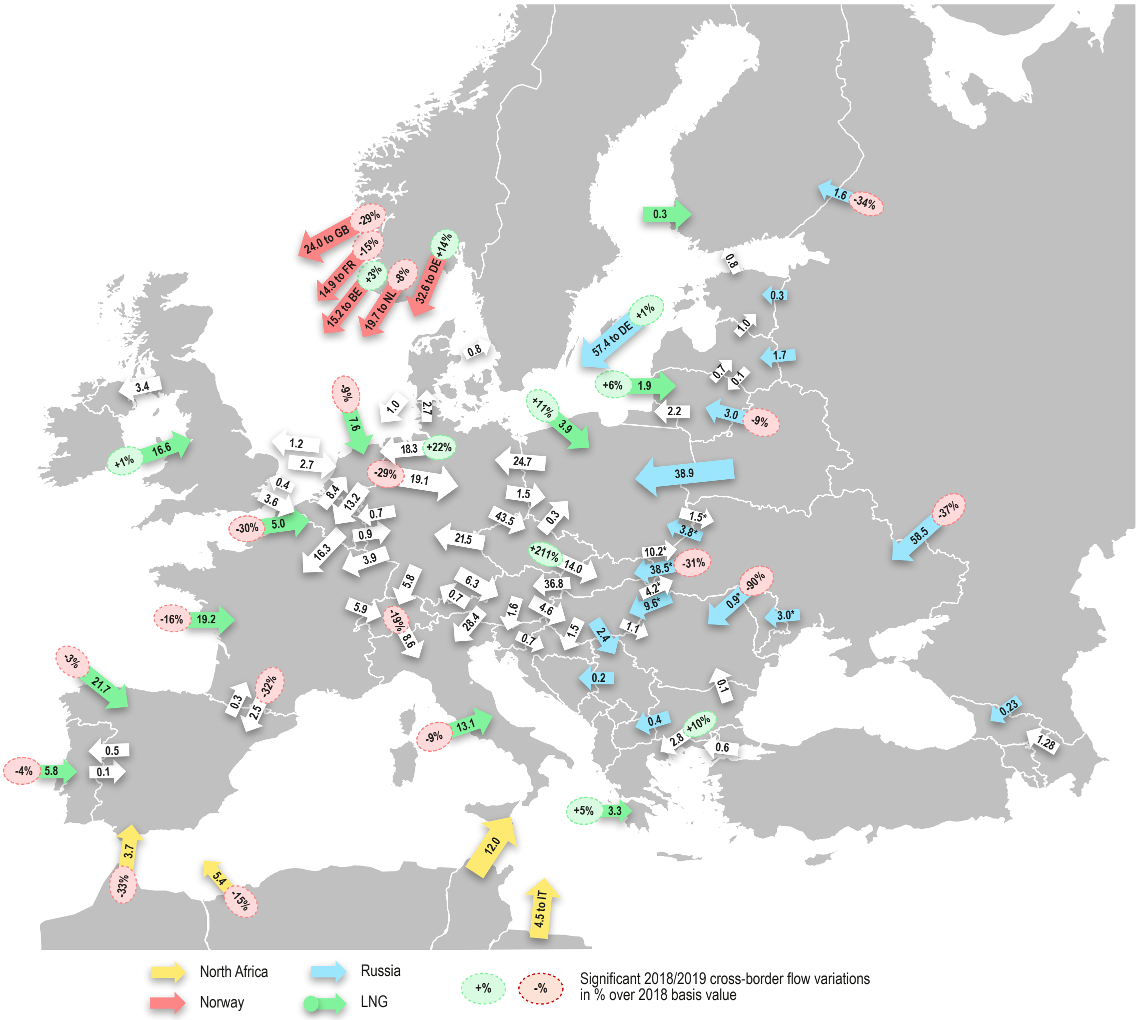
208 The IO NC request TSOs to publish with a frequency of at least once per hour, the Wobbe-index and gross calorific value for gas at all physical interconnection points. Besides, ENTSOG publishes long-term gas quality monitoring outlooks to identify gas quality parameters trends.

Energy community interconnection agreements and cam implementation progression

334 The proper implementation of the INT NC is also crucial for integrating the gas markets of the EnC CPs, both among themselves and with neighbouring MSs. Despite the lack of binding applicability of the interoperability network code at the IPs between CPs and MSs, a few voluntary interconnection agreements have been implemented between Ukraine and Serbia and its neighbouring MSs. The efforts to put into service virtual reverse flows have been of particular interest. The interconnection agreements are to a great extent in line with the INT NC provisions, even if some specific aspects related to gas quality monitoring and data exchange have not been implemented in full.

Annex 1: Back-up figures

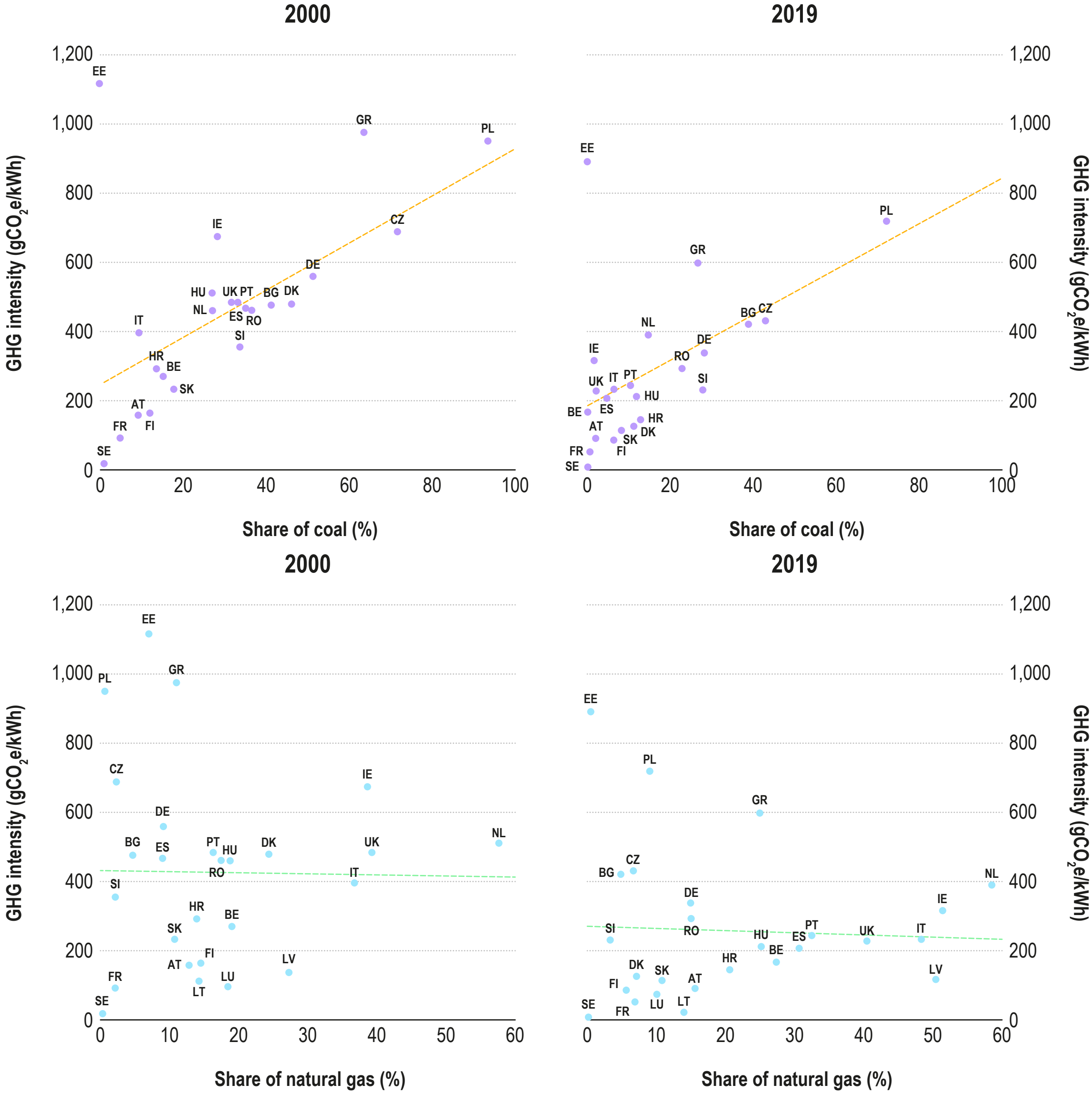
Figure iv: EU and EnC cross-border gas flows – 2020 – bcm/year



Source: ACER calculation based on IEA and ENTSOG (2020).

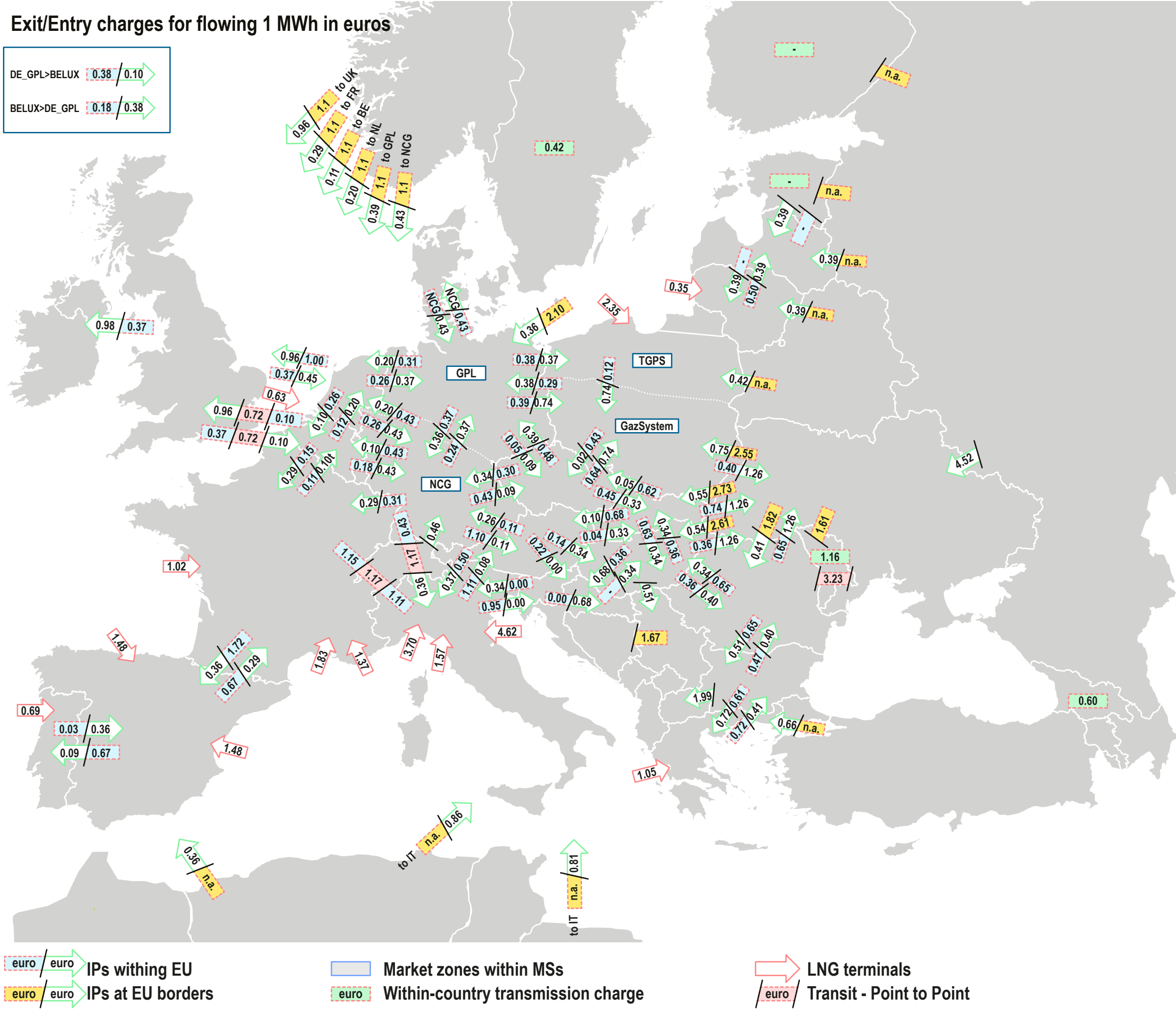
Note: The domestic production of MSs is not included. The reported Norwegian flows into Denmark originate from offshore fields that are connected to the Danish system. The flows into and from Ukraine correspond to nominations received by the TSO.

Figure v: Coal to gas shifts in power generation across MSs – 2000–2020 – % of yearly power production



Source: ACER calculation based on ENTSOG, CEER and individual TSOs (2020).
Note: Estonia still holds a sizeable share of oil-shale power generation.

Figure vi: Comparison of average gas cross-border transportation tariffs and LNG system access costs – April 2021 – euros/MWh



Source: ACER calculation based on ENTSOG, CEER and individual TSOs (2021).

Note: For cross-border IPs, the map displays 20210 exit/entry charges in euros/MWh for the yearly product. See MMR 2016 annex 1 for further clarifications. For LNG terminals the tariff refer to 2020, the figure considers the costs derived from the bundled service (unloading + storage + regasification) of a 1,000 GWh LNG cargo, which regasifies the whole amount in a period of 15 days, plus the entry tariffs from the LNG terminal into the transportation network. Nord Stream tariff is an educated guess on the basis of market intelligence reports assessments. In Poland, the tariffs referring to Yamal will be shown in blue colour. Besides physical flow between the Yamal Pipeline (TGPS) and the Polish VTP (Gaz-System) a backhaul reverse flow is possible. Some tariff values, in red, need to be updated.