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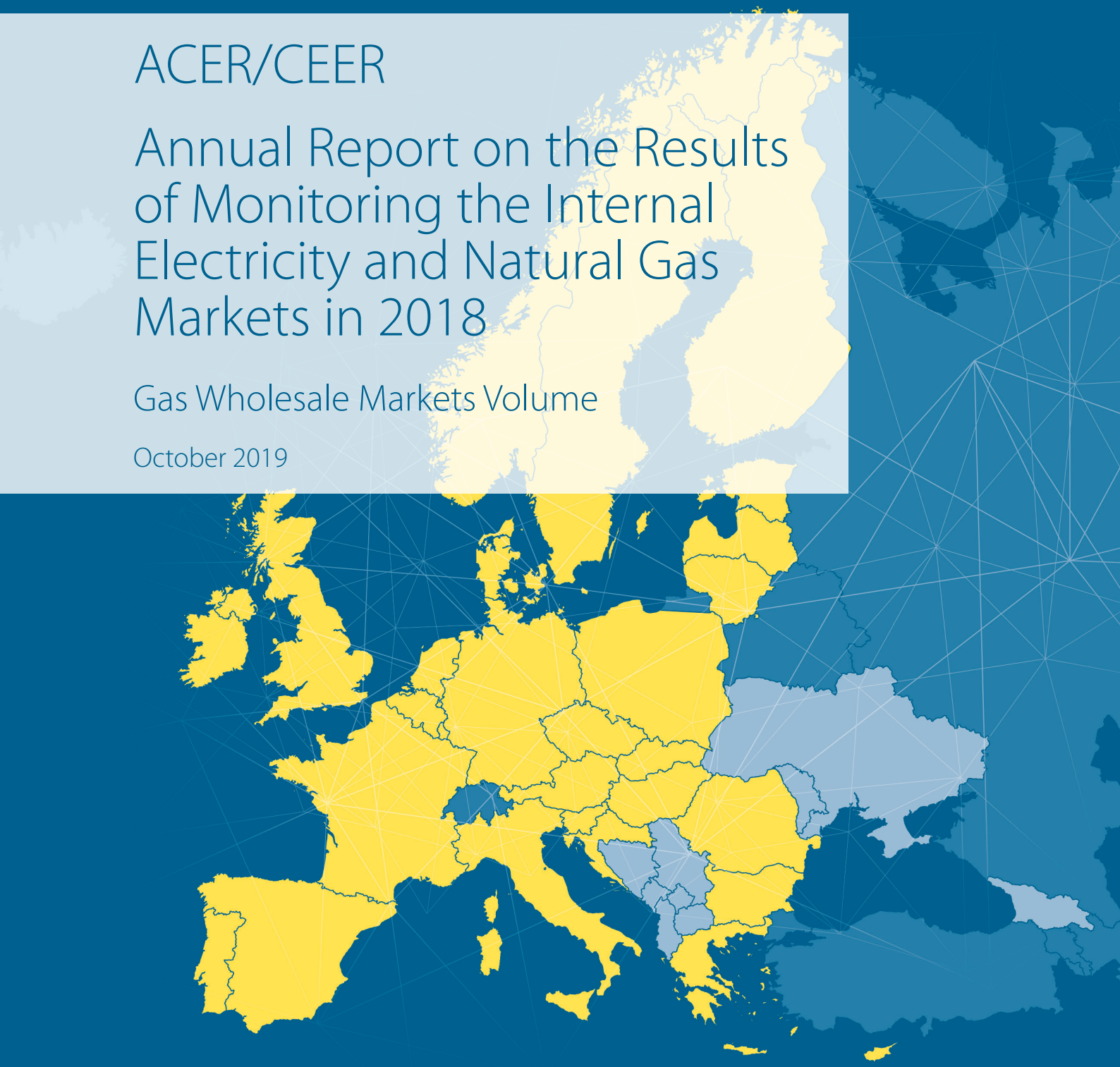
Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2018

Gas Wholesale Markets Volume

October 2019



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The support of the Energy Community Secretariat in coordinating the collection and in analysing the information related to the Energy Community Contracting Parties is gratefully acknowledged.

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Executive Summary

Internal Gas Market

1 **The EU is becoming more dependent on gas imports** as domestic gas production continues to decline (-6.5% compared to 2017). This decrease was offset by LNG (+10%) and increased pipeline imports, mainly from Russia. In 2018, the EU imported 77% of its consumed gas (+2.1% compared to 2017). Biogas production represents still a small share of the total EU consumption (4%).

2 **Gas demand decreased** by 3.7% in 2018, mainly due to weather conditions and lower gas-fired power generation. In an environment of relatively stable household and industrial gas consumption, the evolution of gas demand is becoming more subject to the dynamics of profitability of gas-fired versus coal-fired power generation.

3 **Gas has become a global commodity. Gas prices in the EU are increasingly influenced by global dynamics** and are increasingly interdependent with prices of other global energy commodities. In 2018, for example, the EU gas prices sharply increased during most of 2018 linked to high LNG demand in East Asia and rapidly decreased in autumn 2018 and in the first half of 2019 due to lower than expected demand from China.

4 **LNG and UGS are more and more used as short-term flexibility tools, enabling shippers to balance portfolios and hedge prices on shorter horizons.** The profitability of UGSs increased by the end of the storage year 2018/19 in the most liquid hubs with storage injections starting already in the winter season, taking advantage of lower gas prices. The uncertainty over the Ukrainian transit contracts after 2019 was also a contributing factor. Although the sustainability of this increased profitability is to be tested in the future, the utilisation of UGS and LNG shows that their role is increasingly based on international market dynamics, in addition to their typical SoS role.

5 **European gas supply costs have converged to a significant extent, bringing tangible benefits to consumers.**

- **Differences in gas supply sourcing costs across MSs are today in most cases below 1 euro/MWh.** Just three years ago, differences of more than 5 euros/MWh were still common. Without the gas market reforms (European and national) and infrastructure developments, most consumers would still be paying a premium simply for not being properly linked to the more competitive wholesale markets of the Union. Most supply contracts are now hub-price-linked and only in a few MSs, where oil-linked contracts are still dominant, price convergence shows a distinct pattern.

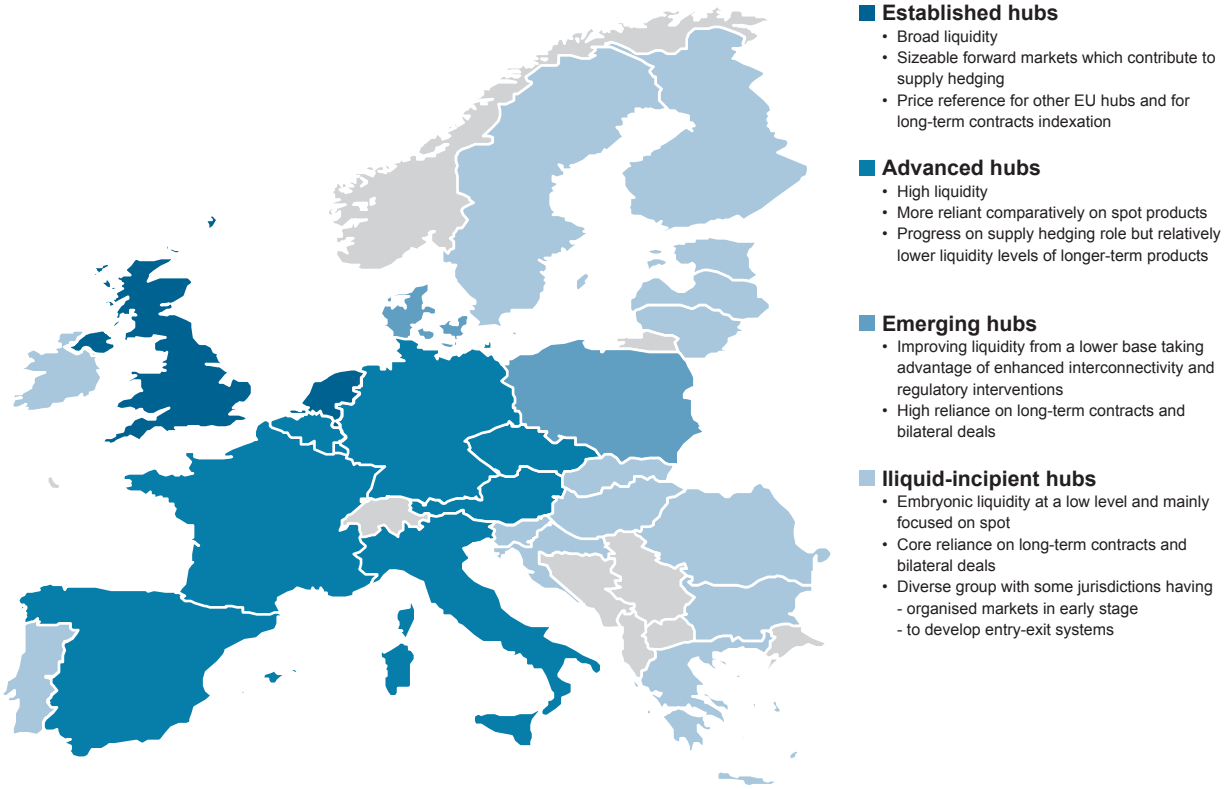
- **Gas hubs in NWE registered some of the highest price convergence levels in the EU to date.** Hub spreads between TTF and the NWE hubs were below 1 euro/MWh for 90% of days. Price integration in the Central and Eastern Europe (CEE) and Mediterranean regions also has improved in recent years. In addition, convergence amongst markets within a given region is usually higher than between markets of different regions.

6 **Gas producers play an increasing role in the European gas market and are moving downstream.** In addition to their rising market share in overall volumes of gas supplied to the EU, producers are increasing their trading activities in MSs, via centralised platforms or via their own trading platforms. Producers are also increasing their bookings of transportation capacity at the interconnector points (IPs) located within the EU, especially of capacity products in the medium-term to long-term timeframe.

Gas Target Model

7 **Gas wholesale markets are generally functioning better, but the gap between better functioning hubs and those without transparent trading venues continues to increase.** Figure i presents a classification of gas hubs based on ACER Gas Target Model (AGTM) metrics[1]. While there are notable positive developments in, *inter alia*, Spain, Italy and Austria, quite a few market areas still have weak or no hub dynamics. In these markets a trading venue with a transparent price mechanism is either absent or not visible during many trading days of the year. These MSs continue to fall behind better performers and will find it harder to catch up. As such, they should take further steps towards implementing the Third Energy Package and/or the AGTM. The Energy Community Contracting Parties (EnC CPs) still show very limited hub trading activity.

Figure i: Ranking of EU hubs based on monitoring results – 2018



Source: ACER calculation based on AGTM metric results.

8 **Market concentration of supply sources is still high in many MSs.** The markets with the most diverse portfolio of suppliers are those in NWE and those with access to LNG. Almost all MSs have access to three different supply sources and while most have sufficient residual supply import capacities, few reach a healthy level of supply source market diversification. Only the wholesale markets in Belux, France, the Netherlands and the UK meet the AGTM thresholds of a diverse and not concentrated market while Italy, Ireland and Spain are close.

9 **In 2018, 76% of EU gas supplies were priced with a hub price reference and the total EU hub-traded volumes increased by 7% compared to 2017.** 90% of this increase is due to the 25% growth of the traded volumes at TTF, the biggest gas hub in EU. More than half of all EU gas volume is traded at TTF. Volumes traded at the EU's two biggest hubs, TTF and NBP, are ten times higher than the other hubs of NWE and one hundred times higher than less liquid hubs.

1 The ACER Gas Target model (AGTM) is a model for the internal gas market (IGM) developed by the Agency, NRAs and gas sector's stakeholders. In order to assess the gap between gas hubs' status and the targeted performance, the AGTM is complemented by a set of indicators, the so-called "market health" metrics and the "market participants' needs" metrics. The results of the market health metrics indicate whether gas wholesale markets are structurally competitive, resilient and exhibit a sufficient degree of diversity of supply; and the results of market participant's needs metrics indicate how liquid their gas hubs are.

10 **2018 saw higher spot price volatility.** This was a short-term factor that influenced hub trading more than last year, following a year of relative low volatility. Volatility was driven by, *inter alia*, extreme weather conditions, global LNG dynamics and relative loss of flexibility tools in the TTF and NBP markets (i.e. the decommissioning of the Rough UGS facility and the production cap on the Groningen gas field).

11 **More gas hubs reached the AGTM's thresholds in the spot and to a lesser extent in the prompt timeframes.** In the spot timeframe, liquidity, competition and number of market participants continues to increase, especially at the hubs in Italy, Spain, Lithuania and Hungary. In the prompt timeframe, while concentration improved at most hubs, most trading activity is concentrated at TTF and NBP and is moving further away from the other hubs.

12 **Hub specialisation, especially for forward products,** keeps on growing led by TTF. The most competitive EU gas forward markets, with frequent trading beyond the season-ahead, continued to be those of the established TTF and NBP hubs.

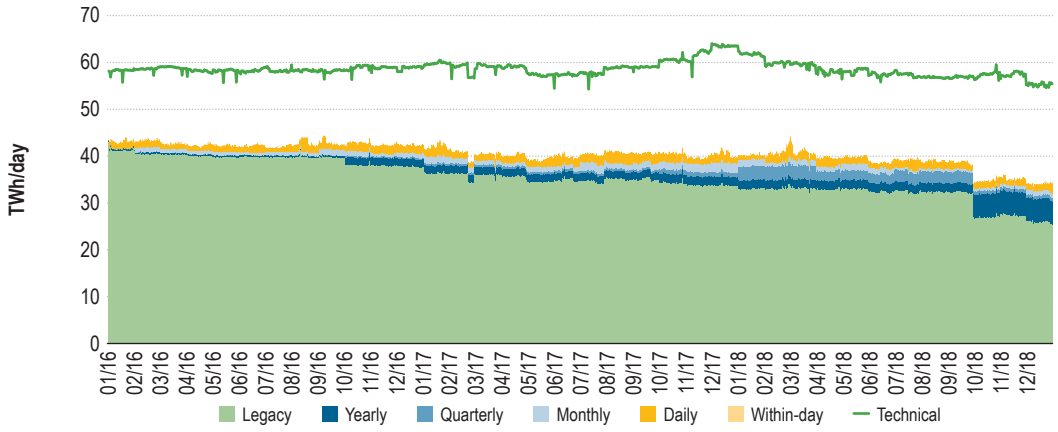
Network Codes

13 **The overall booked transportation capacity decreased year-on-year but in most MSs the expired volume of historical long-term capacity contracts was replaced by new CAM capacity bookings.** However, long-term booked capacity expired at some interconnectors and was not replaced. The main drop in bookings occurred at the IUK and BBL interconnectors. These interconnectors were already mainly seasonally used in the years prior to the expiration of the long-term capacity contracts. Overall, where historical bookings expire, new bookings match better actual needs.

14 **The CAM NC allows shippers better to profile capacity bookings based on actual demand.**

- **Shorter-term commitments dominate new capacity bookings.** 70% of CAM capacity booked for the period 2016–2018 was short-term, 29% was year-ahead and only 1% was longer than one year-ahead. Shippers aim to profile their portfolio of capacity following the seasonality of gas consumption, to choose more freely if shipping gas via pipelines or via LNG and to try to avoid the locked-in transportation capacity effect. The higher degree of capacity profiling is shown in Figure ii.
- **The entry into force of amendments to CAM NC auctions** (e.g. increased frequency of auctions for quarterly products) **immediately increased the bookings of the related products.** Starting from the capacity booked for 2018, more quarterly products and more yearly products were booked via the CAM auctions.
- **Concentration of bookings tends to be higher for the longer-term CAM capacity products** and lower for the shorter-term capacity products.

Figure ii: Type of capacity booked at selected CAM-relevant EU IP sides for the period 2016–2018 (TWh/d)



Source: ACER calculation based on data from GSA, PRISMA, RBP, ENTSOG TP.

Notes: PRISMA covers products auctioned in 2016, 2017 and 2018; GSA 2015, 2016, 2017 and 2018 while RBP from May 2017 to end of December 2018.

15 **Day-ahead price spreads between many hub pairs are often below transportation tariffs, which usually indicates high levels of market integration.** Increased market liberalisation entailing, *inter alia*, the development of gas hubs and enhanced upstream supply competition explain why markets are more integrated. This is further enhanced by a mismatch between current gas demand and legacy contracted transportation capacity and gas commodity, leading over-contracted shippers to engage in cross border trade by placing bids around the short-run marginal costs of inter-hub gas transportation capacity. Where spreads exceed tariffs, this may indicate incomplete market integration.

16 **There seems to be not necessarily a direct link between gas price and the transportation costs incurred when shipping that gas across IPs to reach hubs in competitive markets.** At times, upstreamers seem to adapt their profit margins in order to be able to compete (or keep market share) in competitive markets by pricing their supplies without necessarily passing on the full transportation costs to buyers. As such, in markets where upstreamers face stronger competition, the role of IP tariffs is more marginal in setting the wholesale price.

17 **Divergences in the degree of capacity replacement of expiring historical long-term transportation capacity at IP sides are likely in the future.** It is still too early though to assess possible impacts on price convergence levels linked to the expiration of the long-term transportation contracts. However, as further volumes of long-term capacity contracts will expire in the next years, a differentiation of IP sides is likely (by 2024 more than half of the long-term transportation capacity of 2018 will have expired).

- *Core to supply:* these IPs are likely to maintain current capacity booking levels and price convergence is likely to continue. However, adequate competition should be in place in order to offset the price-segmentation effect of tariffs.

- *Periodic supply:* at these IPs which are booked periodically, capacity bookings are likely to become more price responsive and, overall, are likely to diminish. Price segmentation could re-emerge where these IP sides set marginal supply prices.

- *Portfolio optimisation supply:* reasonably high bookings are expected during the year in these less core IPs as they would be still important in order to supply markets adjacent to core ones.

- *Idle supply:* at these IPs bookings will be low, this would likely bring a loss of price convergence.

18 **The current NRA proposals on the reference price methodology (RPM) for tariffs show that the flexibility provided in how the TAR NC is implemented would maintain some level of tariff competition among MSs.** The TAR NC, which is in the process of being implemented, is expected to improve the transportation tariffs' transparency and cost-reflectivity. Most NRAs seem to use some discretion in their RPM proposal with the aim to pursue a more optimised operation of their national system. However, this could lead to tariff competition among MSs and/or undue cost transfers to neighbouring markets.

19 **The role of the TSO in balancing after the implementation of the BAL NC becomes more short-term and residual, to the benefit of spot markets' liquidity.** Almost all MSs that fully implemented the BAL NC early went beyond the basic BAL NC requirements (for example on information provision) and, in most of them, the TSO decreased its market intervention while the market's spot liquidity increased. In those MSs that implemented the NC later, the TSO increased the procurement of products for balancing closer to real-time, compared to the situation before the BAL NC implementation, and network users accommodated this need. This also happened in MSs that had low levels of spot liquidity before the BAL NC's implementation. The liquidity of the spot markets (especially within-day) in these MSs also increased as shippers became more confident in taking shorter-term positions due to clear rules on imbalance charges and the clearer and more reliable information provisions.

Recommendations

WHAT SHOULD THE ENERGY REGULATORY COMMUNITY FOCUS ON?

20 This Report shows that the Internal Gas Market (IGM) continued to progress in 2018: gas hubs increased their role with even more supply-side competition, price convergence improved and the interconnection and integration of the national markets increased. The ongoing implementation of the gas NCs is reinforcing this trend and is likely to confirm it in the future with the implementation of some regulatory provisions not fully in place yet, e.g. the TAR and BAL NC. However, there is ongoing divergence of market maturity across the EU.

21 While markets work well in MSs representing 70-80% of EU gas consumption, an EU-wide IGM is not fully a reality yet. The implementation of the Third Energy Package is still incomplete in some MSs. MSs should also avoid taking measures that go against the spirit of the Third Energy Package and the interest of the IGM as they tend to have an immediate, adverse impact on market functioning[2]. Similarly, they should abolish any remaining barriers to market functioning like limitations to free cross-border trading of locally produced gas and remove excessive storage regulations[3]. Targeted regulation could be applied to MSs with less competitive and more illiquid gas markets. Such regulation might include gas release programmes to reduce the power of the incumbents.

22 Any new legislative package focusing on upgrading gas market design should build on the current gas market and regulatory model, as not to create regulatory uncertainty and potentially deter market participants from trading, investing and/or entering new markets. Any new legislation should develop from a clear vision on the role of (natural and renewable) gas and consider the context provided by the Clean Energy Package (CEP). It is likely that the European Commission will develop a legislative proposal for a "Gas Package" in the next couple of years. Such a Package should provide clear definitions on the entry-exit systems and on the VTPs in order better to clarify the minimum operational requirements for a functioning wholesale gas market.

23 In order better to adapt to the rapidly evolving market conditions, the European regulatory framework should include a means for continuous monitoring of the NCs' effectiveness and for amending them where appropriate, without creating unnecessary regulatory uncertainty. TSO products and services may need to evolve, in line with consumer needs to increase the overall efficiency in the utilisation of the EU gas networks and, consequently, to decrease the overall costs for the end users. This also implies that the European TSOs make the maximum effort to standardise contracts and procedures, so as to remove barriers in the European wholesale gas markets (e.g. contracts, guarantees, procedures, information exchange and data exchange formats, products, products descriptions).

24 Market monitoring and market surveillance to detect and deter market manipulation and anti-competitive behaviour should complement regulatory implementation towards an EU-wide IGM. This will safeguard IGM benefits such as fair competition and high social welfare levels. Hence:

a) EU institutions should ensure adequate attention to market surveillance and the tasks attributed to the Agency by Regulation (EU) No 1227/2011[4].

b) The responsible institutions at national level should do the same for the tasks attributed to them in accordance with the same Regulation (EU) No 1227/2011. NRAs are encouraged to acquire certification on security aspects to access REMIT national data. This will also limit the need for double reporting by market participants.

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2 For example, on March 2019 the EC sent a letter of formal notice to Romania for failing to correctly implement certain requirements of the Gas Directive and the Security of Gas Supply Regulation. In particular, the EC found that the system of regulated wholesale prices introduced in December 2018 in the Romanian gas market goes against the EU legal requirements and is not adequate to sustainably achieve the objective of protecting household customers from excessive price increases. See http://europa.eu/rapid/press-release_MEMO-19-1472_en.htm.

3 i.e. those storage regulations, usually in the form of storage obligations that distort market functioning (e.g. result in an adverse impact on price convergence, lower number of market participants, etc)

4 Regulation on wholesale energy market integrity and transparency (REMIT). See: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32011R1227

25 Continuous alignment of the Energy Community to the *acquis communautaire* of the EU is a pre-condition for enhancing market integration and cross-border trading with and between the Contracting Parties.

GAS INFRASTRUCTURE AND FUTURE ROLE OF GAS

26 The EU gas sector shows high levels of interconnectivity and security of supply, with increased levels of market integration and competition. Gas flows are guaranteed without interruption even in tight situations. In parallel, parts of the gas transportation infrastructure are currently far from being fully utilised. Considering that the expired volumes of long-term capacity contracts might not be fully replaced at some IP sides, there might be a future risk that regulated infrastructure becomes stranded, resulting in social welfare loss for consumers. Besides, the implementation of all gas projects included in the EU TYNDPs is highly unlikely (they would exceed the needs of additional infrastructure in the coming years) and few PCIs became or are likely to become operational by the established deadline.

27 In this context, NRAs and MSs should continue to apply a careful approach in the approval of new investment related to traditional natural gas infrastructures. Particular caution should be used about their financial support at the EU or national level.

28 The gas sector should also contribute more to the European decarbonisation efforts, especially with more tailored and decarbonisation-related investments.

- There is currently a lack of clarity on which will be the most cost-efficient technologies in the power and gas sectors that would allow to reach the decarbonisation targets. Hence, R&D may help to foster innovation that would allow those technologies to be developed.

- In case a new Gas Package is put forward, it needs to ensure that the proposed legislation to decarbonise the gas sector does not lead to segmentation of the market, as experienced in the electricity sector over the last decade. Market-based solutions and a minimum of incentive schemes should be preferred in order to avoid increasing the costs for end consumers.

- Part of the CEF funds could be redirected to gas projects that support the decarbonisation objectives, possibly targeting pilot power-to-gas technologies at an initial stage of development. But, overall power-to-gas should be a contestable activity. Those funds need to reach a broader target audience, other than the TSOs.

ACER GAS TARGET MODEL

29 The AGTM metrics are improving for most MSs' gas wholesale markets, particularly those metrics that measure the functioning of hubs' spot markets. However, the AGTM thresholds are still not generally met, especially when considering the liquidity of the hub's forward markets (apart from TTF and NBP) and the upstream supply-side competition.

30 Furthermore, the fragmentation of the EU internal gas market into numerous gas hubs may hinder the functioning of the smallest gas hubs. At the end of 2018, the 14 illiquid hubs covered just 12.5% of EU total consumption. The AGTM establishes that, when the AGTM indicator thresholds are not met, the concerned NRAs should consider measures aiming at improving integration between hubs as outlined in the AGTM, e.g. some form of merger.

31 In order to promote the implementation of the AGTM, the regulatory community could develop a framework that facilitates market mergers across MSs, which elaborates on technical governance and procedural aspects.

32 Where hubs suffer from a lack of (spot) liquidity, NRAs should guarantee that gas transits and domestically produced gas can be traded at the VTP without restrictions and should ensure that balancing rules are implemented in a way to promote liquidity, i.e. in line with best practice.

33 A methodology for monitoring market power based on the capacity ownership to complement the current AGTM market health metrics (e.g. the capacity ownership at the IPs and of the gas production, storage and regasification facilities) could be developed. This methodology could be also used as the basis for potential regulatory measures, e.g. capacity release obligations.

34 The regulatory community and the European Commission should consider whether further assessments or harmonisation requirements on the application of conditional capacity products and services are beneficial. This is relevant as in some MSs the share of conditional capacity products over the total allocated capacity products is high, even beyond 50%. The solution shall consider several elements, including whether the usage of conditional capacity products has a positive CBA, if it meets the transparency requirements and if it is harmonised across MSs.

IMPLEMENTED NETWORK CODES AND CONCENTRATION OF BOOKINGS

35 The EU gas wholesale markets have become more dynamic; market participants use long-term and short-term capacity products according to business requirements and economic fundamentals. NCs are contributing to these changes and a coherent implementation of the NCs increases liquidity, competition and price convergence.

36 The implementation of the CAM NC is favouring the possibility for shippers better to profile their capacity portfolio and to incorporate short-term price signals in the management of their capacity at the IPs. Starting from the capacity booked for 2018, more quarterly products and more yearly products were booked via the CAM auctions because of the entry into force of some amendments to the CAM NC[5]. NRAs, the European Commission and ACER could consider the possibility to further increase the frequency of CAM auctions with a standardised timing in order to make them even more useful for the network users.

37 The degree of concentration of the capacity booked by network users is higher for the longer-term capacity products and lower for the shorter-term capacity products. This raises the question of whether the CAM NC and the EU and national competition laws are adequate and coordinated enough to handle potential future concentration of capacity bookings. NRAs should monitor the concentration levels of capacity bookings for the different capacity products so as to implement any necessary actions in a timely manner. ACER will monitor the booking concentration levels.

38 In the balancing zones where the BAL NC was fully implemented, the TSO increased their procurement of products for balancing closer to real time and the network users accommodated this need. This also happened in balancing zones with low or very low levels of spot liquidity before the BAL NC implementation. With clear balancing rules and better information on the balancing's status, network users are more willing to take positions in the spot timeframe, thus increasing the liquidity of the spot products in a balancing zone. A full implementation of the BAL NC, the minimisation, and possibly the full removal, of the balancing services and the abolishment of the balancing platforms by 2019 should be carried out by all the TSOs and NRAs. If by the deadline established by the BAL NC to remove the balancing platform a national trading platform cannot be set up, all the balancing activities could be carried out in an adjacent trading platform, as approved by the NRA well in advance of the deadline, with a view to full network user's balancing.

39 NRAs shall continue the implementation of the NCs having a regional view in mind. For example, NRAs should urge TSOs to coordinate and to apply a standardised approach to the creation of the VIPs[6] and to facilitate the transfer of (secondary) capacity between network users in order to optimise the usage of the EU network.

5 In particular, the increased frequency of the auctions for the quarterly products (from one auction to four auctions) and the move of the actions for the yearly products closer to the start of the gas year, from March to July.

6 The acronym VIP refers to virtual interconnection point. In accordance with the CAM NC, where two or more IPs connect the same two adjacent entry-exit systems, TSOs will offer the sum of their available capacities at a VIP.

PRICE LEVELS AND TAR NC

40 The TAR NC, which is in the process of being implemented, is expected to improve the transportation tariffs' cost-reflectivity. The national consultations on the TAR NC have been carried out during 2017 and 2018 in most MSs[7]. A diversity of reference price methodology (RPMs) have been proposed as NRAs are applying some flexibility with the aim to pursue a more efficient operation of their transportation systems. However, the analysis shows that there might be a risk of competition among MSs on tariffs and/or undue cost transfers to neighbouring markets. In this context, NRAs shall set their transportation tariff systems based on the TAR NC principles.

41 The tariffs at the IPs shall be set in accordance with cost-reflectivity and transparency principles in order to guarantee a level playing field. Also, NRAs should implement ACER's recommendations in the respective RPM as they contribute to a more balanced TAR NC implementation.

42 Any proposed RPMs' adjustments should be justified, based on an assessment of their effects elsewhere in the network. When considering implementing the tariffs' adjustments, NRAs should take a regional view so that the setting of tariffs does not risk distorting future market functioning.

43 As the price of short-term transportation capacity tends to represent a reference for hub price spreads (when transportation capacity is available), NRAs should set short-term capacity multipliers at levels that will safeguard the current high levels of gas price integration in the IGM. However, this should be balanced with the principle of fairness in sharing network costs between infrastructure users. In the future, the allowed revenues for the TSOs might need to be recovered from a lower level of demand, putting upward pressure on tariffs. As a counterbalance, NRAs could focus on aligning investment and depreciation schemes to mitigate this risk.

7 Some MSs missed the deadline established by the TAR NC, which was the end of May 2019.

1. Introduction

44 This MMR, which is in its eight edition and covers the year 2018, consists of four volumes respectively on: the Electricity Wholesale Market, the Gas Wholesale Market, the Electricity and Gas Retail Markets, and Customer Protection and Empowerment. It covers the EU MSs and, for selected topics, also the Contracting Parties of the Energy Community.

45 This Gas Wholesale Volume presents the results of the monitoring of the European gas wholesale markets in 2018 and their trajectory towards an Internal Gas Market.

46 The Volume is divided into three analytical chapters. Chapter 2 presents the status of the European Internal Gas Market in 2018; Chapter 3 focuses on assessing the performance of gas markets based on the Agency's Gas Target Model (AGTM) indicators, which focus on the structural degree of competition and the functioning of gas markets; Chapter 4 analyses the market effects of network codes on market functioning. The Volume also provides a set of recommendations based on the outcome of the analytical work performed by ACER.

47 In order to calculate the AGTM indicators, for the fourth year ACER has used anonymised and aggregated REMIT data. For selected AGTM's indicators, this Volume only displays the results for a sample of MSs. The results for all MSs, together with results of other analyses, are published in the "CHEST" database available on the ACER's website[8].

8 See: https://aegis.acer.europa.eu/chest/category/2/list.

2. Overview of the Internal Gas Market in 2018

2.1 Demand and supply developments

48 In 2018, demand for gas in the EU decreased by 3.7%, to 5,047 TWh. Lower gas-fired power generation and milder weather in the fourth quarter account for most of the reduction. A trend of more favourable gas-to-power economics, which had underpinned the switching from coal to gas during 2016 and 2017, did not continue in 2018 as the profitability of gas generation was negatively affected by rising prices of the commodity[9]. In addition, reduced EU electricity demand (-2% yoy), together with rising RES production, resulted in limited demand for gas for power generation.

49 Figure 1 illustrates the evolution of gas demand since 2014, whereas Figure 2 shows the breakdown of EU power generation by type of technology. Both Figures reveal that gas consumption was lower than in 2018. In 2019 (up to April), gas demand has decreased again at a 1% year-on-year rate so far.

Figure 1: EU gross gas inland consumption – 2014–2018 – TWh/year and % variation yoy

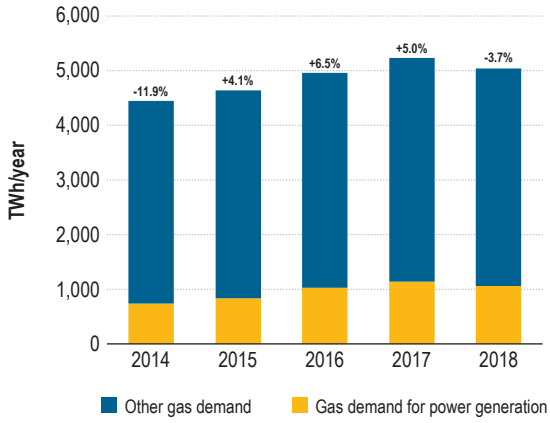
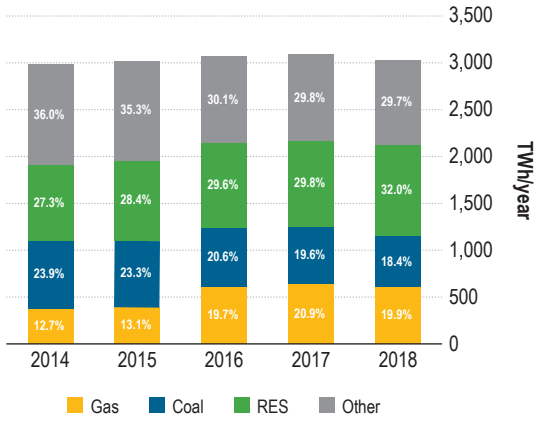


Figure 2: EU electricity generation breakdown by technology – 2014–2018 – TWh/year and % of total



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

50 While the EU as a whole saw decreasing gas consumption, the aggregated figures mask the underlying variety at MS level. Yearly demand variations reflect heterogeneous local market dynamics, such as economic growth or the relative importance of gas for industry and electricity generation. Remarkably, gas demand reached record highs in March 2018 in several MSs driven by unusually cold weather. As Figure 2 shows, in 2018 gas-fired power production accounted for 20% of EU electricity generation. The national market shares of gas-fired production were the highest in the UK and Italy, where gas accounted for around 40% of the total.

51 Thanks to its flexibility and lower CO2 emissions compared with coal-fired electricity generation, natural gas can act as a bridge for massive deployment of RES (the Clean Energy Package aims for a 32% share of RES in primary energy consumption by 2030, which entails a RES share of over 50% for power generation). The use of natural gas in electricity generation is also set to increase as coal and nuclear power stations in various MSs are phased out.

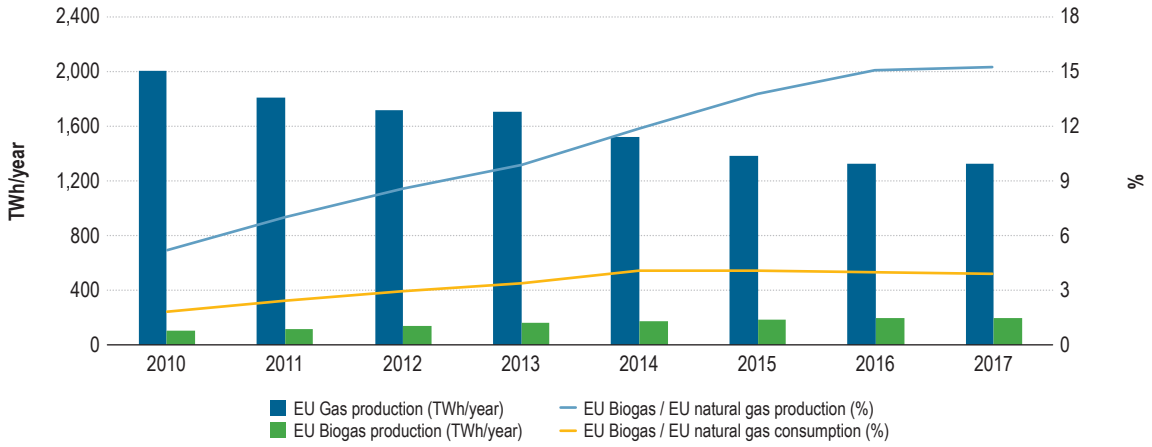
9 Section 2.2 elaborates on the reason for that. Clean spark spreads measure the profitability of gas plants, taking into account the cost of EUAs certificates to emit carbon. In Germany, in accordance to ICIS Heren data clean spark spreads evolved from 10 euros/MWh to 3 euros/MWh on average for 2016 and 2018 respectively. However, since the beginning of 2019, gas profitability for power generation has improved again.

52 However, to reach the ambitious 2050 emission targets with reductions in the order of 80-95% compared to 1990 levels[10], the use of unabated natural gas would need drastically to decrease or decarbonise. In this context, the EU is, for example, pushing for large-scale renovation of buildings to improve their energy performance[11].

53 Renewable and low-carbon gases – biogas, biomethane and hydrogen from different origins (e.g. blue or green hydrogen) could in the future depending on their economics (partly) replace natural gas[12]. The existing gas networks could accommodate this transition, although adaptations will be needed. The reduction of the methane leakages across the entire supply chain is also imperative for a more sustainable use of natural gas[13].

54 Figure 3 illustrates the increasing importance of biogas production, albeit still from a low base. Biogas accounts for 15% of EU gas production, with Germany, the UK and Italy in the lead. Production costs of biogas are still considerably higher than for natural gas. On average, biogas accounts for less than 4% of EU gas consumption. However, its importance varies between MSs, whereby in Sweden, Denmark and Germany, biogas consumption exceeds 10%.

Figure 3: Evolution of biogas production in the EU – 2010-2017 – TWh/year



Source: ACER calculation based on Eurostat.

55 Most biogas is consumed close to production sites either for heating or electricity generation. The volumes injected into the network – mainly at distribution level – are still low, chiefly due to higher production costs, gas quality and other technical constraints. The notable exceptions are Denmark and the Netherlands. On average, injections into the network represent less than 4% of biogas production in the EU. In Denmark and the Netherlands, they exceed 25%, thanks in part to higher financial support.

56 Another ambition of the EU is to explore and exploit potential synergies between the gas and electricity sectors. On the one hand, power-to-gas[14] technologies could enhance electricity storage (particularly when produced by RES) and increase the flexibility of the energy system. On the other hand, gas and electricity networks could be linked to enhance overall optimisation. This entails strengthening the coordination of infrastructure planning, to determine the best locations and sizes of such investments.

10 In November 2018, the EC presented its strategic long-term vision for a climate-neutral economy in 2050. See: https://ec.europa.eu/clima/policies/strategies/2050_en. Milestones in the process are 40% and 60% reductions by 2030 and 2040, respectively. All sectors shall contribute to this climate neutral transition according to their technological and economic potential; expected main contributors are energy efficiency and a higher share of RES in the energy mix.

11 MSs shall establish strategies aiming at sizeably decarbonising national building stocks by 2050. See: https://ec.europa.eu/energy/en/topics/energy-efficiency/energy-performance-of-buildings.

12 Associations forecast that biogas production could reach 10% of EU gas demand in 2030. Besides, the EC has stated that hydrogen may play a larger role in the future. Blue hydrogen is produced from natural gas using carbon capture and storage, whereas green hydrogen is obtained from the electrolysis of water using electricity https://www.biogas2020.se/wp-content/uploads/2017/11/nr-1-eba-perspectives.pdf.

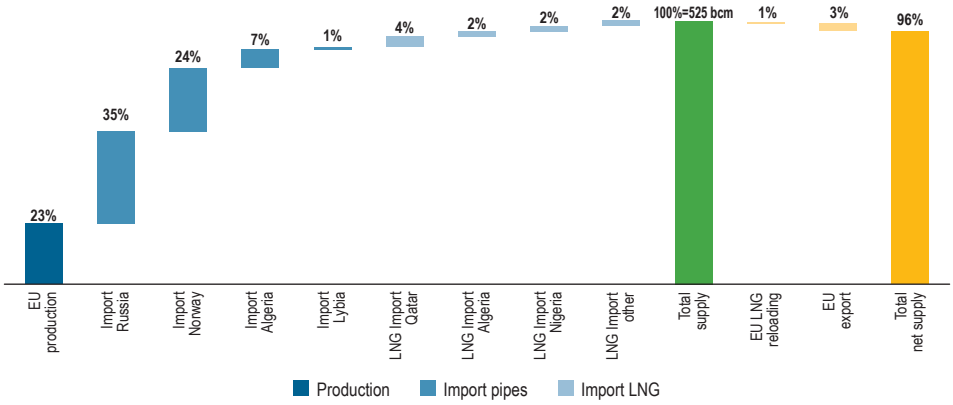
13 According to the EEA, methane represents 11% of total EU greenhouse emissions. Lack of consistent and transparent data make the estimation challenging, but studies suggest that leakages across the entire supply chain account on average for 2-3% of EU gas sales. See https://www.eea.europa.eu/publications/european-union-greenhouse-gas-inventory-2018.

14 The use of electricity, i.e. electrolysis to produce hydrogen, and possibly methane that can be injected into the gas network in the second step.

57 With regard to transport, the penetration of natural gas vehicles (NGVs) remains limited in Europe. It accounts for less than 5 bcm of annual consumption and represents 2% of the EU's light duty vehicles (LDVs) fleet. The most optimistic projections[15] predict that 10% of EU LDVs sales will be NGVs in 2030, and more than 30% for buses and trucks, where electricity is still less of an option. In contrast, projections for electric vehicles (EVs) forecast a 30% share of new LDVs sales by 2030, on average.

58 The reliance of the EU on external gas imports to cover for reduced domestic production (-6.5% yoy) continued to increase in 2018 (+2.1% yoy). Indigenous production accounted for 22.8% of total EU gas supply. A lower cap[16] on the extraction of gas from the Dutch Groningen field and production reductions in the UK and Romania explain ongoing decreases (see Figure 4).

Figure 4: EU gas supply portfolio by origin – 2018 (100 = 525 bcm, %)



Source: ACER calculation based on International Energy Agency, Eurostat and GIGNL[17].

59 The main gas supplier to the EU, Gazprom, further increased its yearly sales to an all-time high of 182 bcm. In its main market, it aims for a market share of around 35%[18]. Gazprom is adapting to the changing EU gas market environment by incorporating hub-based price models in its contracts and by selling more gas directly at NWE hubs. The settlement of the anti-trust case covering the CEE and Baltic countries with the European Commission in May 2018, whereby export restrictions and destination clauses in supply contracts were abolished, is another impetus for a more hub-oriented pricing model. The company also organised gas auctions and direct sales for delivery at selected NWE and CEE network points[19] on a dedicated platform. This novel mechanism seems to aim to attract new business by selling uncontracted volumes.

60 Norwegian gas supply was stable in 2018 with 126 bcm delivered. It is noteworthy that Norway has overtaken European domestic production as the second largest source of EU gas supply. Norwegian gas suppliers have a longer tradition of hub price-based contracting, and are a relevant source of supply flexibility in NWE. Sonatrach, the Algerian gas supplier, delivered 45 bcm (-1.5% yoy) of gas in 2018. At the request of its long-standing buyers in Italy and Spain, it is now also including some hub-indexed pricing terms in its contracts[20].

61 LNG gross supplies to the EU grew 10% yoy to 55 bcm or 10.5 % of overall EU gas supplies. Russian and US suppliers increased their presence, reducing the dominance of Qatari LNG supply.

15 See the European NGV Association 2030 Roadmap: www.ngva.eu.

16 The Groningen production cap was set at 19.8 bcm/year, or 2 bcm lower than in the preceding year. The field produced 54 bcm/year as recently as 2013. UK production totalled 40.7 bcm, a -2.9% drop. Romania, the third largest EU producer, supplied 10.2 bcm, a 3.9% drop.

17 International Group of LNG importers. See: http://www.giignl.org/.

18 See for example: https://uk.reuters.com/article/russia-gazprom-europe/update-2-gazprom-grabs-record-share-of-europe-gas-market-despite-challenges-idUKL3N20L3BM.

19 German, Austrian, Dutch and Slovak VTPs, but also deliveries at IPs such as Tarvisio, Baumgarten or Waidhaus.

20 See for example: http://www.realinstitutoelcano.org/wps/portal/rielcano_en/contenido?WCM_GLOBAL_CONTEXT=/elcano/elcano_in/zonas_in/ari128-2018-escribano-algerian-presidential-elections-energy-reform-agenda.

62 Gas exports from the EU into Ukraine amounted to approximately 10.7 bcm, a drop of circa 4 bcm yoy. Higher reliance on domestic production and higher Ukrainian storage withdrawals, as well as the consumption decline explain the reduction[21]. Ukraine has a policy goal to end gas imports by 2020, however this might be challenging to achieve given that domestic production has not increased in the last years as planned. Exports to Ukraine are nonetheless a relevant factor influencing the liquidity and prices of CEE hubs, as will be further explored in Chapter 3. Besides, Ukrainian companies expressed interest to export gas into EU MSs, via the backhaul utilisation of the existing interconnections.

63 The enhanced adaptation to hub-indexes and direct hub sales by upstream suppliers lifted the share of hub-price based supplies up to 76% on average across Europe. However, there are still some differences between regions[22].

2.2 Price developments

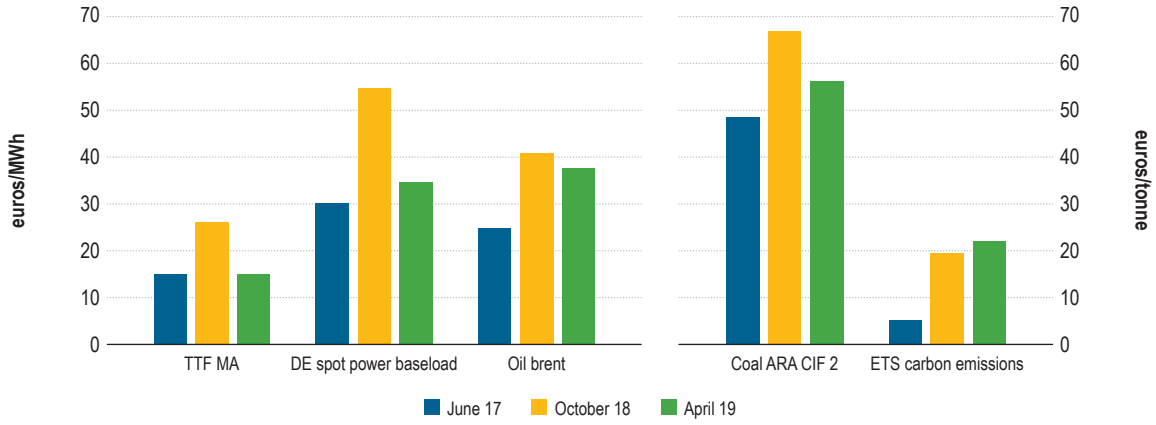
64 European hub prices increased during most of 2018. For example, NWE hub spot prices were on average 50% higher (a rise of around 8 euros/MWh) in the third quarter of 2018 than in the same period of 2017. However, by April 2019 prices had dropped to 15 euros/MWh, from a high of 27 euros/MWh in September 2018.

65 A mixture of factors drove higher gas price levels in 2018. Firstly, the price interlinkage among energy commodities had an upward effect on gas prices with the coal-gas price correlation being the most determinant factor:

- Oil prices rallied from summer 2017 to October 2018 (+60%) led by higher global consumption.
- The prices of carbon emission rights increased in 2018. The prices of European Emission allowances more than tripled since May 2017, due to the EU-wide reduction of carbon allowances in place from 2019.
- Coal prices also went up (by 70% between mid-2016 and autumn 2018). Coal and gas compete in setting the marginal price for power generation in many MSs.

66 Factors more closely related to gas demand and supply fundamentals were growing demand in Asia, which increased competition for LNG supplies, and lower EU UGS stock levels in spring.

Figure 5: Overview of average energy commodity prices for selected months.



Source: ACER calculation based on ICIS and Thompson Reuters.

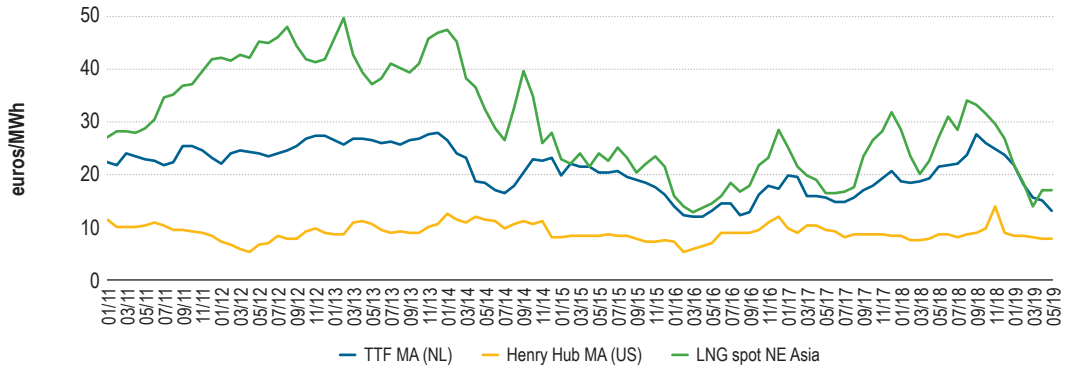
21 The country has not purchased gas from Gazprom since November 2015 due to disputes on contractual conditions.

22 See the IGU Gas Price 2018 report showing results per European region (also including selected EnC CPs): gas-on-gas price formation, either hub-indexations of direct hub sales applies to 96% of supplies in the NWE region (Benelux, Denmark, France, Ireland, Germany and the UK); it drops to around 76% in the CEE region (Austria, the Czech Republic, Hungary, Poland and Slovakia). It has gained ground in Scandinavia and Baltics - up to 60% - and accounts for 44% in the Mediterranean area (Greece, Italy, Portugal and Spain, Italy). Gas-on-gas price formation is rising as well in the SSE region (Bulgaria, Croatia, Romania and Slovenia but also Serbia, Bosnia and Herzegovina and FYROM), although is still limited to 40%.

67 Figure 5 gives an overview of the price evolution for selected energy commodities. It shows that prices of oil, gas, coal and electricity dropped from their highs in October 2018 in line with changing market fundamentals (see Section 2.4). More importantly, the graph exposes the growing price fluctuations of global energy commodities, of which natural gas is increasingly part, and that overall their prices seem to become more interdependent.

68 Figure 6 provides an overview of the evolution of international gas wholesale prices in recent years. It shows that interdependence in gas price formation is also consolidating at global level facilitated by, for example, a greater availability of LNG and the growth of inter-regional hub hedging[23]. Even so, the distinct fundamentals of each specific region explain price disparities.

Figure 6: Evolution of international wholesale gas prices, 2011 – May 2019 – euros/MWh



Source: ACER calculations based on ICIS Heren. In the absence of a transparent and liquid Asian hub, the LNG spot NE Asia index is based on the prices of OTC trades reported to market intelligence agencies.

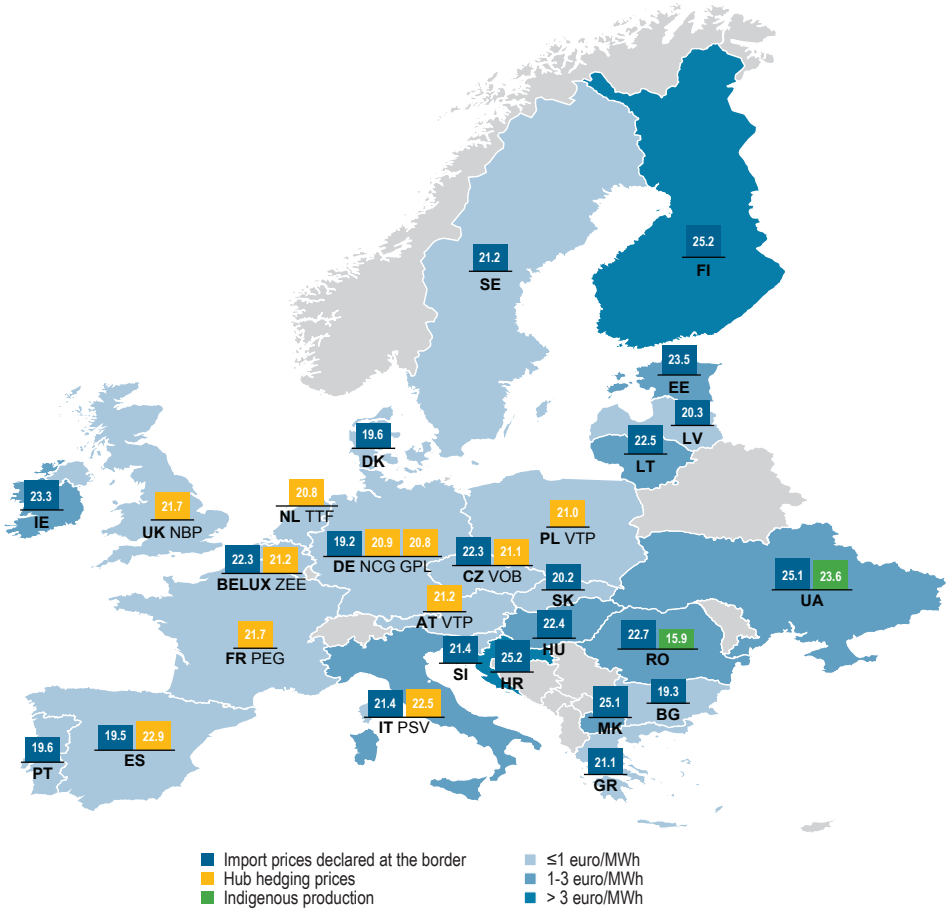
2.3 Assessment of supply sourcing costs

69 As in previous years, ACER has gauged the prevailing gas sourcing costs for EU gas wholesale markets. The methodology used considers a basket of hub products, long-term supply contracts and domestic production prices[24]. Figure 7 presents the results for 2018. Average suppliers' sourcing costs increased in 2018 with respect to the previous year for reasons discussed in the previous Section. The expectation for 2019 is, however, that sourcing costs will decrease again, at least on the basis of the price developments observed until summer 2019.

23 E.g. global LNG players increasingly hedge portfolios on TTF.

24 See MMR 2014, Annex 6 for details on the general methodology and specific data used for selected MSs.

Figure 7: 2018 estimated average suppliers' gas sourcing costs by EU 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 EU MSs and EnC CPs.

Note: Assessment of supply sourcing costs for Georgia, Serbia and Bosnia and Herzegovina was not feasible. Import prices for AT, FR and PL could not be assessed.

70 Supply sourcing costs of MSs continued to converge in 2018. Differences across MSs are in most cases below 1 euro/MWh. As such, supply cost convergence across Europe has mostly been reached. Just five years ago, there were relevant differences among quite a number of MSs: for example, supply sourcing costs in the Baltic or SSE regions were still in the order of 5 euros/MWh higher than at NWE hubs. This means EU gas market integration has delivered significant benefit to consumers, who otherwise would have paid a premium simply for not being properly connected to the more competitive part of the EU gas market.

71 In recent years, sourcing at the EU's liquid hubs generally resulted in more attractive prices compared to LTCs. However, due to hub price rises up to autumn 2018, bilateral contracting turned more cost competitive in some MSs. For example, Bulgarian, Portuguese or Slovakian partially oil linked LTCs were more price competitive than purchasing gas at TTF. However, this situation is expected to flip again in 2019, following significant hub price drops. Overall, in periods of higher hub price volatility, price differentials among oil-indexed and hub-based contracts tend to increase, due to the slower responsiveness of the former to gas-on-gas market developments.

72 The combination of *marginal supply* and *market opportunity* pricing[25] tends to explain sourcing cost differences among MSs. Both in turn are affected by competition elements, transportation costs and markets functioning well. Price differences may also appear between distinct sourcing mechanisms within a country. As an illustration, Spanish and Italian long-term supply contracts – from selected supply origins[26] – are often more competitive than purchasing gas at the PVB and PSV hubs, respectively, whose prices seem not fully to align to this competitive setting[27]. Cheaper bilateral supplies may not have reached the hubs, or if they had, they would have been sold with a mark-up.

73 A better functioning of hubs positively promotes supply competition and price determination which may help to reduce the cost of the marginal supply source. Selective gas release initiatives could also contribute to this objective, especially in SSE.

74 Supply costs in the EnC CPs continue to be higher than in EU MSs. This is the result of the prevalence of less price-competitive long-term contracts in the absence of competition and a limited number of distinct supply sources. Since 2016, Ukrainian suppliers have been acquiring sizeable gas volumes from EU traders in the context of the termination of direct imports from Russia. In 2018, this was still the case, although total imports from the EU fell. Ukrainian indigenous gas production is currently more price competitive than imported gas. This supports the interests of some Ukrainian producers to export gas in the future to the EU.

25 *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 maximize revenues. This is the so-called *market opportunity* price.

26 E.g. from Algeria in Spain or from Russia in Italy. See Eurostat Comext data for details of declared supply prices per border. Reported supply prices are expected to include all transportation costs to bring gas into VTPs.

27 In the case of Italy, higher sourcing costs may also be explained to some degree by the fact that the TENP pipeline – on the Swiss part - does not fall under EU regulation. This may reduce the competitiveness of capacity allocation processes, particularly for the short-term time frame and may lead to contractual congestion at certain periods. If the Swiss part of TENP would fall under EU regulations, then this would likely have a positive effect on market functioning.

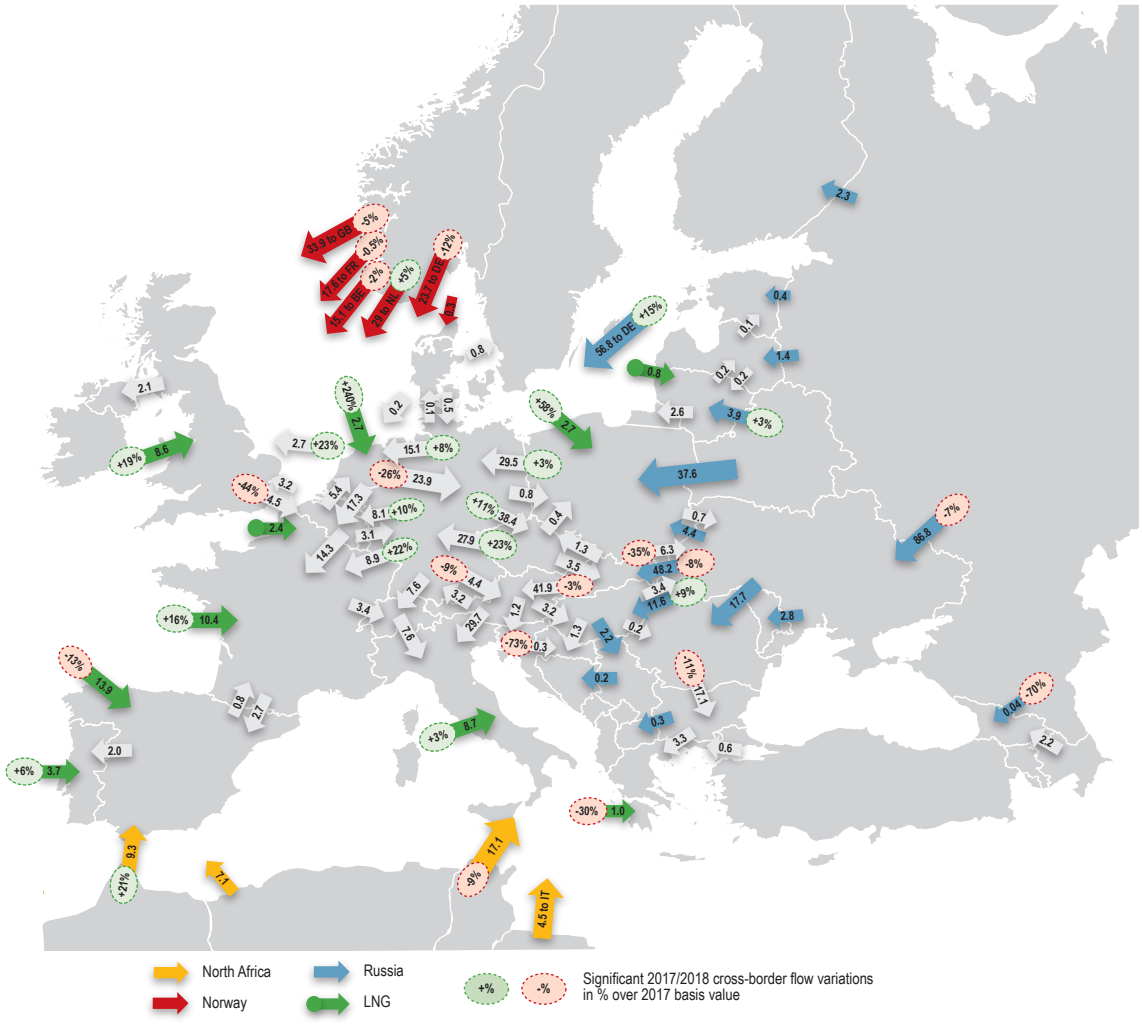
2.4 Infrastructure and system operation developments

75 This Section covers the main gas flows developments, including LNG and UGS flows.

PHYSICAL GAS FLOWS ACROSS EU BORDERS

76 Figure 8 provides an overview of EU and EnC gas cross-border flows in 2018.

Figure 8: EU and EnC cross-border gas flows in 2018 and delta with 2017 – bcm/year



Source: ACER calculation based on IEA (2018).

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.

77 Pipeline and LNG flows increased in 2018 to compensate for declining EU domestic production.

78 The Russian northern routes, Nord Stream and Polish Europol, operated close to their peak capacities[28] in 2018. If the Nord Stream 2 project materialises, it will add 55 bcm/year of extra import capacity by 2020. Full flow capacity also depends on the completion of both strings of EUGAL across Germany. This expansion could further (re-)direct Russian supplies into Central and North-West Europe via Germany and the Czech Republic.

28 Aided by higher MSs demand in summer months, the Russian exports' flow profile is becoming flatter, dampening the seasonal curve.

79 This project, together with Turkish Stream 2 (planned for 2020), could crowd out gas flows into the EU originating from Ukraine and Slovakia. The Ukrainian transit contract with Russia is due to expire by the end of 2019, and the Slovak one by 2024. A possible extension is being negotiated and lower transportation tariffs applicable across Ukraine might play a supportive role in attracting flows. Gas flows into the EU via Ukraine during 2018 decreased by 6.5% with respect to 2017. Flows from the EU into Ukraine dropped by circa 30%.

80 EU LNG gross imports were 10% higher in 2018 compared to 2017, but showed different patterns across seasons and MSs. LNG deliveries were modest until the last quarter of the year, but have boomed since then[29]. In absolute terms, Belgium, France, Italy, the Netherlands, Poland, Portugal and the UK imported more, whereas Greece, Lithuania and Spain decreased LNG imports. EU LNG re-exports also recovered in 2018. Section 2.4 discusses the reasons.

81 Despite changing market fundamentals, gas flows are accommodated in a smooth fashion, showing the extent to which many markets have improved in terms of flexibility and liquidity. For example, in March 2018, following an unexpected cold weather spell in Northern Europe, gas flows managed to secure physical balancing of the gas system. Despite a huge spike in spot prices, the flexibility of the system (including demand-side measures) prevented potential demand interruptions.

82 Lower domestic production has made the Netherlands more reliant on gas imports from Germany (+8% yoy), while its exports dropped by 24% yoy. The Netherlands could become a net importer in 2019. Germany is augmenting its transit role, transporting Russian gas into Europe[30]. As stated, this role centres on the steady utilisation of Nord Stream and Europol pipelines.

83 Remarkably, in November, some flows were channelled northwards from Italy into Switzerland and Germany, following the completion of reverse flow capabilities at the border. Surplus LNG deliveries at PSV made this possible[31]. Croatia and Slovenia also completed reverse flow capabilities between their systems.

84 The closure of the British Rough storage facility together with the expiration of LTCs at IUK and BBL interconnectors is making the UK market more reliant on spot LNG deliveries and Norwegian gas as sources of supply flexibility. Exports from the UK into the Continent have become less attractive for market participants, even in summer months. Flows from the UK to Belgium dropped by more than 40% yoy. Section 4.5 explores this issue in more detail.

85 After the consolidation of the two French market zones in November, flows from TRF into the Spanish PVB hub rose slightly. Hub price signals were more favourable for Spanish imports given augmenting spreads[32]. Nonetheless, most of the time spreads still fell under transportation charges, as Section 4.5 analyses. At the beginning of 2019, the French and Spanish NRAs rejected the investment request for enhancing the interconnection capacity between the two zones – i.e. STEP project – considering it as insufficiently mature due to the limited market interest, the lack of firm capacity offered by the project[33] and reservations on the cost-benefit analysis results.

INFRASTRUCTURE INVESTMENT

86 Various MSs continue to aim to diversify their supply capabilities in order to enhance competition. This has resulted in various proposals for new pipelines and LNG terminals, either along established supply axes or via new gas corridors.

29 E.g. LNG's share of EU supply accounted for 9% in January but rose to 16% in December.

30 Gas exports from Germany raised 8% yoy. If Nord Stream 2 is consolidated, and Dutch domestic production continues to fall, Germany is expected to play an even more active transit role in Europe.

31 As mentioned in Section 3.5, price spreads in both Italy and Spain against NWE hubs were notably tighter in the last quarter of 2018. Larger LNG availability discouraged pipeline imports from NWE. The situation, however, reversed from the beginning of 2019.

32 Former South-France TRS prices were more aligned with PVB ones. The institution of a single French TRF VTP with a lower price resulted in relatively higher spreads vis-à-vis its Spanish counterpart what attracted some flows.

33 See: https://www.cnmc.es/sites/default/files/editor_contenidos/Notas%20de%20prensa/2019/20190122_STEP_ENG.pdf.

87 There are selectively located infrastructure gaps, mostly in the SSE region, which if (and when) resolved would clearly promote market competition and integration.

88 The prospect of declining natural gas consumption in the future and its potential replacement with so-called renewable gases calls for prudence in committing financial support to new gas infrastructure investments, as their long-term financial sustainability might not be guaranteed. In this respect, financial means committed for European Projects of Common Interest could be redirected towards gas projects supporting clean energy objectives.

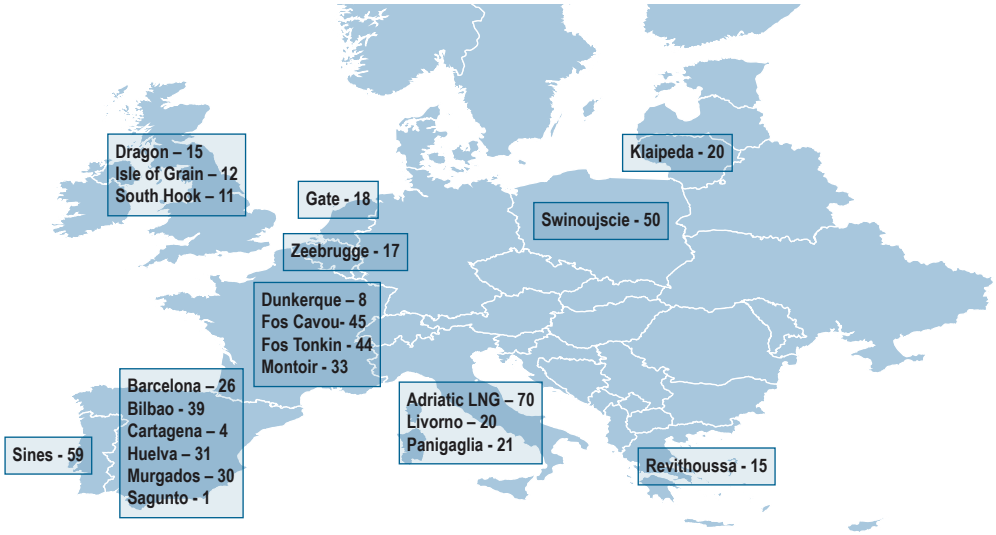
ANALYSIS OF LNG MARKET PERSPECTIVES

89 Gross LNG deliveries into the EU increased by 10% in 2018. The decline in EU gas domestic production, the enhanced availability of LNG and global LNG markets shifting to more flexible supply terms[34] are all paving the way for increasing imports. While the import of LNG has gone up for the fourth consecutive year, its potential for growth has been kept in check by pipeline suppliers adapting their prices in order to keep their market share as well as shippers prevailing pipeline supply commitments.

90 In parallel, the interdependence of gas price formation across global regions is strengthening due to the rising influence of LNG trading. LNG accounted for 33% of global gas traded volumes in 2017, 10 percentage points more than in 2013.

91 The EU benefits from having a number of hubs with liquid forward markets. In the absence of a recognised international LNG price benchmark, liquid EU hubs act as key price references for hedging global LNG portfolios. In addition, the EU is able to attract sizeable volumes of surplus LNG cargoes thanks not only to the size of its market but also because it has spare regasification capacity and ample UGS capacities. Even though average LNG terminal utilisation increased over the last years from 21% in 2016 to 26% in 2018 and EU terminals have been enhancing their operational flexibility to allow for more transhipments and re-loadings[35], EU LNG terminal utilisation rates are still relatively low. Figure 9 gives an overview of individual LNG terminal utilisation rates.

Figure 9: Average utilisation rate of technical regasification capacity of individual LNG terminals in 2018 - %



Source: ACER calculation based on GIE ALSI data.

Note: Average utilisation rates are indicative. In the context of the operation of a gas grid other factors determine what can be considered high utilisation levels.

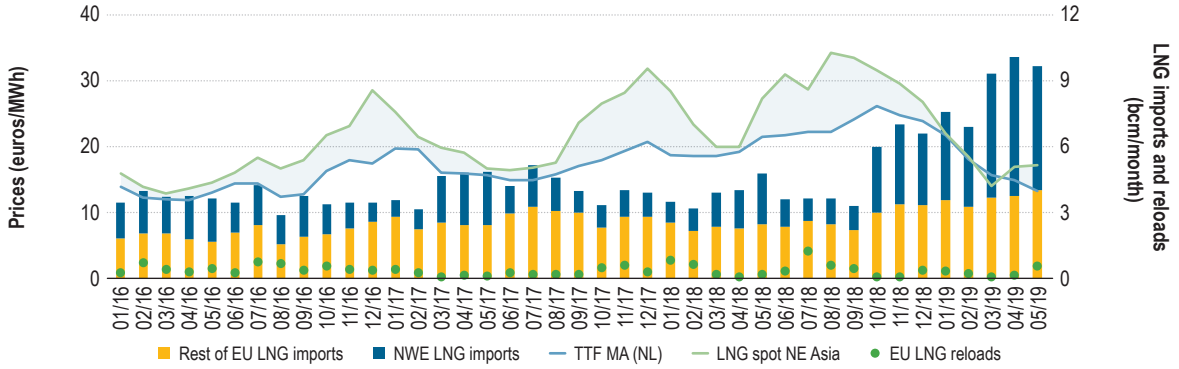
34 At global level, the LNG industry is shifting into a shorter-term and more flexible market. New contracts have a shorter duration and there is a clear shift away from destination or reselling restriction clauses, so cargoes can divert midway to react more easily to spot price signals. Producers are offering more and more extra-production as spot cargoes, while aggregators and traders are managing portfolios by purchasing and selling LNG on different contract durations. In 2018, 25% of global LNG imports had a spot contractual basis (i.e. were delivered within 90 days from the transaction date)

35 LSOs are promoting alternative smaller scale uses to counterbalance low regasification figures in some periods. Among those are the use of LNG to supply non-grid connected areas, or as bunker or road fuel. LNG-trucks fuelling has particularly experienced a robust growth across 2018.

92 The volumes of the LNG that land in Europe are increasingly driven by market developments in the Asia-Pacific region, which accounts for 76% of global LNG demand[36]. As illustrated in Figure 10, over the last years, the European-North East Asian price spread has shown a pronounced seasonal component, peaking regularly in winter, reflecting weather-driven demand. North East Asian countries still tend to have fewer pipeline supply options and less storage capacities[37]. This puts extra upward pressure on prices during peak demand periods. Generally, at times of wider Eropean-North East Asian spreads, LNG cargoes are diverted to Asia and the volume of EU LNG re-loads increases as well.

93 However, in 2018 North East Asian prices maintained a premium during most of the year, including the summer months. This price gap abruptly narrowed from October 2018 onwards. Prices in East Asia dropped below NWE levels for the first time in four years. Milder weather in East Asia and lower than expected gas demand growth in China were the key factors. As Figure 10 shows, LNG imports into the EU ramped up since the fourth quarter of 2018, particularly in NWE. Consequently, prices fell dramatically and part of the delivered LNG was injected into storage facilities even though it was still gas winter season.

Figure 10: Comparison of TTF-North East Asian price spreads vs EU LNG imports and reloads – 2016 – May 2019



Source: ACER calculation based on GIE ALSI and ICIS Heren data. LNG spot NE Asia index is based on OTC prices. (See Figure 6 Notes).

94 The high European-North East Asian spreads observed until autumn 2018 indicated a tighter global LNG market. The key driver for that had been the vast demand growth in China. The country has been absorbing most of the extensive LNG liquefaction capacity added globally in recent years, tripling its LNG imports over the last five years. However, the events from the last quarter of 2018 onwards have started to change this. Forthcoming LNG supply projects – by 2024 global liquefaction capacity is expected to grow by 25%, with half of the growth coming from the US – could further contribute to this revised scenario. This will very much depend on how LNG demand in Asia develops.

95 Evidence of supply tightness were the steep increases in LNG shipping rates during 2018, which more than doubled yoy. In some instances, the rising costs for shipping LNG cargoes from the US and Russia to Asia offset the favourable spreads and some cargoes were reoriented into the closest – and thus cheaper to access – European market. As an example, 12% of US LNG exports were delivered to Europe in 2018 compared to 35% during January-April of 2019. Shipping rates, however, have eased since the beginning of 2019.

96 Overall, the increased flexibility offered by LNG helps market participants to use it more as a competitive instrument[38] that serves to balance portfolios and hedge prices on shorter horizons. This is making LNG deliveries into the EU more price-responsive, but also more unpredictable. It also confirms that the EU is the global last resort LNG market. As an illustration, in November 2018 EU LNG terminals operated at their highest levels in the last 7 years. LNG's ability to respond at shorter notice to price signals together with extra supplies made available

36 Japan (26.5%), China (17%) and South-Korea (13.5%) account for more than half of global LNG imports. Spain, the largest EU LNG importer, accounts for 4%.

37 In the case of China, new pipeline interconnections with Russia could deliver up to 40 bcm/year from 2019. Additional UGS capacities in development could also soften its rising LNG dependency. The Japanese gas grid is not fully interconnected.

38 The growing number of market participants has increased the complexity and competitiveness of the global LNG industry. According to GIGNL figures, in 2018 20 countries (including re-exporters) sold LNG to 42 end-markets. This compares to six exporters and eight importers in 2000.

in the Atlantic basin[39] were the key underlying causes. Only fourth months earlier, NWE terminals had reloaded for the first time more LNG than what they had regasified into the network.

97 The above masks differences among MSs in terms of LNG supply price-responsiveness. This is due to a combination of factors, including the local role of LNG supply, the ease of access to liquid hubs – where prices and volumes can be more easily hedged – the size and terms of the prevailing contracts, and the technicalities of terminals and their access regimes. To cite a case, the operation of the Polish Świnoujście terminal is mainly flat across the year to accommodate for long-term supply contracts, whereas British and Benelux terminals exhibit a more irregular profile that follows more closely prompt markets' price dynamics.

98 LNG terminals also compete among themselves in attracting deliveries at regional level. The access conditions and offered services and tariffs reflect this[40].

99 LNG is expected to increase its share in the future EU gas mix mainly as a means to compensate for lower EU domestic gas production. Some estimates forecast LNG imports to double by 2030[41]. Increasingly integrated EU markets are supporting the option of LNG supply even in those MSs having no direct access to LNG. In other words, the cost of LNG including the transportation cost makes LNG at times competitive even in these markets[42]. An enhanced LNG supply role is an important part of the EU's diversification strategy. Not only to guarantee security of supply, but also to discipline price formation from competing pipeline suppliers.

ANALYSIS OF UNDERGROUND STORAGE FACILITIES MARKET PERSPECTIVES

100 UGS facilities play both a security of supply and a market role, the latter related to price management in markets. In a mid-term timeframe, storage sites back seasonal supply flexibility, chiefly in winter, and tend to assist forward price hedging. In the shorter-term, UGSs can facilitate the management of physical portfolios that are exposed to demand fluctuations as well as the optimisation of gas stocks against the variation of hub spot prices.

101 The physical specificities of individual UGS sites, storage obligations, access conditions[43] and, last but not least, prevailing contracts impact the operational strategy of UGS users.

102 Although there are differences among MSs, the operational strategy has adapted to the changing environment and is shifting towards shorter-timeframe storage transactions. In practice, UGSs support the management of volume and price risks in prompter horizons, in addition to an often-reduced mid-term role[44].

103 This transition has been driven over the last years by the narrowing of hubs' summer/winter season-ahead spreads, the key drivers for mid-term storage utilisation. As Figure 11 illustrates, ex-ante seasonal summer/winter price spreads at EU hubs have narrowed from 4 euros/MWh in 2012[45] to 0.9 euros MWh in 2018, making

39 Russia's Yamal terminal also plays a relevant role in the rise of the seasonality of LNG deliveries into EU. Shipments to Asia across eastern routes in the Arctic are restricted in winter because of ice, so they come initially to the EU from where they can be transhipped.

40 LNG tariffs are not fully cost-reflective in various markets. Cross-subsidisation is defended either for security of supply reasons or with the aim of disciplining the prices offered by pipeline suppliers, particularly where LNG sets the marginal price. Another case is when LNG demand is too low to ensure cost-revenue recovery. However, artificially low tariffs may distort fair competition. The latest CEER LNG Task Force study elaborates further on this subject. See: https://www.ceer.eu/documents/104400/-/-/57d62db2-db0a-e611-2a49-85703d1d54d6.

41 E.g. See BP Energy Outlook 2019. Complementarily, ongoing LNG projects could increase regasification capacity by another 22 bcm by 2023, several of them financed by the EU and with a regional perspective.

42 As an illustration, in the spring of 2019 the German hub prices were at premium in NWE. Price-competitive LNG was delivering in the region, but has no direct access to Germany. Adding to the fuel cost the transportation costs made LNG supplies more expensive in NCG or GPL than at the coastal Belgian or Dutch hubs.

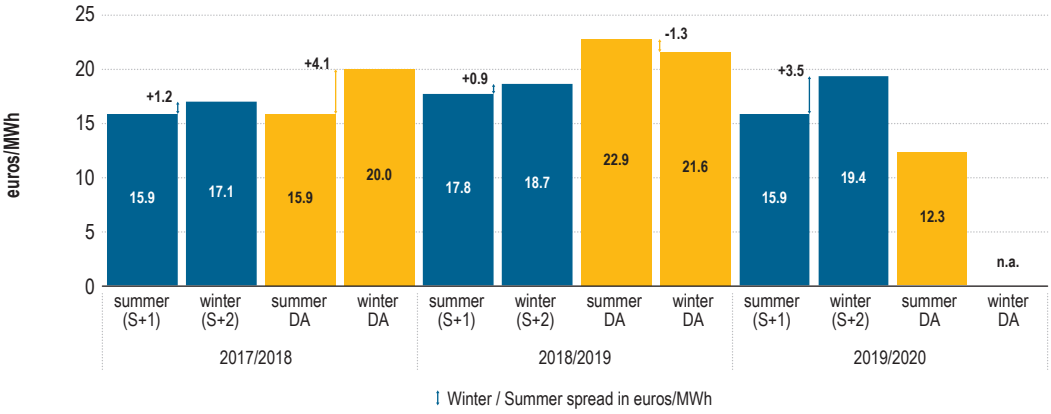
43 All EU UGS facilities must guarantee TPA, either regulated (where the NRA sets the access conditions and tariffs) or negotiated (where the site owner set freely fees and products). There is not a standard allocation mechanism established by the EU regulation and auctions and FCFS are the most commonly used. Storages offer injection, stocking and withdrawal capacities in a bundled manner, mainly for seasonal or yearly periods. Customers are usually responsible for booking transmission capacities to reach the sites, although some SSOs offer delivery at the hubs, managing by themselves the booking of transmission capacities.

44 Both the strategies are interrelated as market participants may initially conclude trades in order to hedge seasonal spreads and then arbitrage those contracts as they cascade, adding profitability to the initial intrinsic positioning. The value captured is influenced by UGSs' services tariffs. For example, new SSO models look into linking the price of storage services to the actual summer-winter spreads for risk hedging.

45 See estimates from 2010 to 2017 in MMR 2017, Figure 11.

UGSs mid-term bookings financially less attractive. Seasonal spreads have mostly narrowed due to enhanced gas supply flexibility, for instance by large UGSs stock capacities, enhanced market interconnection, increased access to LNG spot cargoes, more flexible terms of supply LTCs and a growing reliance on hub sourcing. Less pronounced seasonal gas demand variation - falling winter peak heating demand and growing summer cooling demand - has also contributed to this trend. As a result, ex-ante hub seasonal spreads have been guided to a large extent just by the variable UGSs cycling costs between seasons.

Figure 11: Comparison of ex-ante season summer/winter spreads vs actual spot prices at the TTF hub – 2017–2019 – euros/MWh



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

Notes: 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. Summer 2019 day ahead prices have been assessed until mid-August. It was not possible to assess Winter 2019/2020 day ahead prices given MMR publication dates.

104 As Figure 11 illustrates, the unpredictability of spot prices was higher in recent years. As such, actual DA summer/winter spreads have become more irregular – even negative at certain occasions – driven by varying weather conditions, oscillating gas needs for power generation and overall more volatile hub prices. This fosters a more short-term utilisation of UGSs.

105 Selected developments impacted North West EU supply flexibility in 2018. The closure of the Rough UGS site in the UK and the production caps set at Groningen in particular put the seasonal supply role of UGS in focus. In the case of the UK, those translated into wider ex-ante summer/winter spreads (2.4 euros/MWh at NBP vs 0.9 euros/MWh at TTF). In March 2018, following a cold spell, EU UGS sites recorded the lowest stock levels of 20% of capacity for the last eight years (the average of the previous seven years having been 35%).

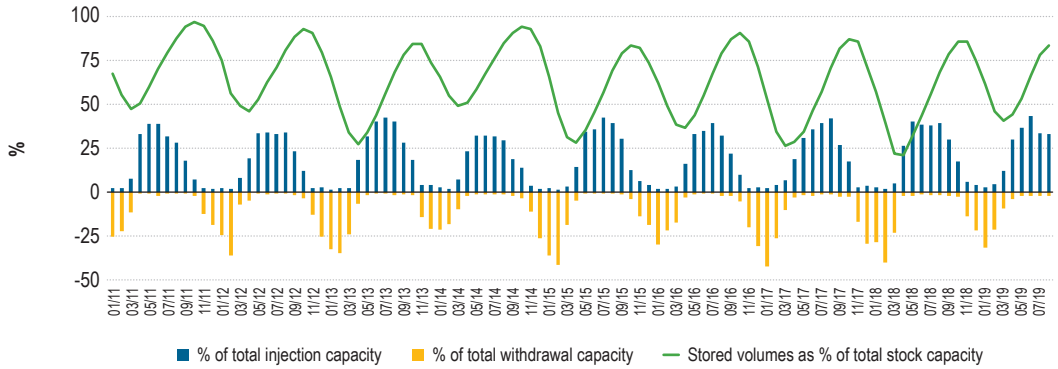
106 However, market fundamentals changed at the start of the 2018/2019 winter season: lower demand, extra LNG deliveries and decreasing hub prices. This resulted in high UGSs stock by the end of the 2018/2019 winter, with gas injections also occurring during the winter season, as some players tried to take strategic advantage of unusually low prices. UGS stocks were by March 2019 already 50% higher than the average of the five preceding years. It should be noted that in some markets (e.g. Hungary and Slovakia) storage fields are also being filled to peak levels in anticipation of a possible end of gas deliveries via the Ukraine transit pipeline. These combined effects prompted the appearance of sensibly larger ex-ante summer/winter spreads[46].

107 These last aspects are illustrated in Figure 12, which shows UGSs stocks, injection and withdrawal levels (relative to their maximum delivery capabilities) for the sum of all EU storage sites. Although the large aggregation of data, the distinct types of storage sites and the varying fundamentals of each season make it difficult to clearly observe shifts in trends, it can be seen that injections across 2018 summer months were flatter and

46 As Figure 11 shows, the seasonal spread for the year 2019/2020 in TTF accounted for 3.5 euros/MWh. Season+1 prices in the month of March 2019 were on the low side, given high stock levels and the expectation that sizeable LNG deliveries would have continued depressing prices across 2019 summer months. However, that trend was not anticipated to last until the 2019/2020 winter. This turned Season+2 prices comparatively higher. The uncertainty over the continuation of transit flows across Ukraine in 2020 could also have played a part in the market participants' choices.

at the highest level of the last 7 years, in order to refill stocks. Although the high stocks at the beginning of the season softened the urgency to fill in storage sites, shippers kept taking advantage of favourable price signals to inject gas. These changes reflect more volatile market fundamentals. The Figure reveals as well that injection and withdrawal rates are reasonably moderate in relation to total delivery capabilities[47]. This shows that there is further ground to increase their market responsive operation.

Figure 12: Monthly injections, withdrawals and stock levels as percentage of operational EU UGS capacity – 2011 – July 2019



Source: ACER calculation based on GIE AGSI+.

Note: Injection and withdrawal maximum capabilities are not constant though the year. Withdrawal capacity tends to be maximum when stocks are closest to maximum capacity and lowest when it is nearly empty. The opposite holds for injections.

108 In the case of Ukraine, the country is trying to incentivise the use of its ample storage capacity – 31 bcm, the largest in Europe – by EU companies. This is also to compensate for their lower utilisation by Russian suppliers. Beyond competitive charges, Ukraine has also offered, as an added incentive, 12 bcm of gas storage capacity free of tax and customs fees to EU shippers willing to use their UGSs sites. Ukrainian storages' peak stock levels were just at 55% of capacity in 2018.

109 Overall, despite the increasing EU reliance on external imports and the loss of flexibility discussed in paragraph (105), seasonal security of supply is in most MSs sufficiently guaranteed with a more market-based approach to storage, even during exceptional circumstances.

110 Therefore, regulation of UGSs and offered services of SSOs shall continue to consider not only the security of supply aspects but also the shorter–term flexibility benefits that these infrastructures offer to the market. A more market-oriented approach to UGSs also favours prompt hub liquidity, as market participants can make more flexible use of capacities and services to hedge their positions. This approach entails limiting UGS strategic storage obligations, as those may restrict market competition by adding operational complexities and imposing extra costs. This policy is also being backed by the promotion of cross-regional cooperation, as outlined in the Security of Gas Supply Regulation EU 2017/1938.

47 The physical characteristics of the storage sites impact the possibility to use the storage volumes rapidly, independently of the storage capacity itself. For example, salt cavern sites account for only less than 20% of EU UGS stock capacity, but their aggregated maximum withdrawal deliverability sums up to circa 40%. The tariffs for injecting and withdrawing also contribute to this.

3. Assessment of the Gas Target Model metrics

111 The ACER Gas Target model (AGTM) is a model for the internal gas market (IGM) developed by the Agency, NRAs and gas sector stakeholders. At its core are competition at, and liquidity of gas hubs. The AGTM sets the following goal for the internal gas market: "(...) competitive European gas market, comprising entry-exit zones with liquid virtual trading points, where market integration is served by appropriate levels of infrastructure, which is utilised efficiently and enables gas to move freely between market areas to the locations where it is most valued by gas market participants". In order to assess the gap between gas hubs' status and the targeted performance, the AGTM is complemented by a set of indicators, the so-called market health metrics and the market participants' needs metrics.

112 Within the context of the AGTM vision for the IGM, this Chapter looks into the market structure, transactional activity and resulting prices at gas wholesale markets in EU MSs, using indicators recommended in the AGTM and additional metrics.

113 The results of the *market health* metrics indicate whether gas wholesale markets are structurally competitive, resilient and exhibit a sufficient degree of diversity of supply; and the results of *market participant's needs* metrics indicate how liquid their gas hubs are.

114 *Market participants' needs* metrics have been calculated using anonymised and aggregated data reported to the Agency under Regulation (EU) No 1227/2011 (REMIT). However, these metrics could be calculated only for those transparent trading venues with sufficient trading activity of standard gas products[48].

115 The AGTM advises that hubs that do not score well against the proposed metrics should be integrated with other hubs. The aim of hub integration is to facilitate better market functioning to foster greater market liquidity and competition to the benefit of consumers.

3.1 Supply diversification and resilience of EU gas wholesale markets

116 Market health describes a broad set of competition aspects associated with gas hubs[49]: the number of geographically distinct gas supply sources, diversity of upstream gas suppliers and the hubs' potential to meet gas demand in its area without its largest upstream supplier. This set of metrics is related to aspects of upstream competition, while Section 3.4 presents the indicators that focus on competition in the hub's transparent, organised trading venues.

117 As described in Section 2.1, five significant sources of upstream supply feed the EU's gas markets: pipeline imports from Russia, Norway and Algeria, indigenous production, and shipments of LNG from various sources. In recent years, liquid EU hubs have become an important source of gas supply for many MSs, therefore these are included in the market health assessment as a source of supply in their own right.

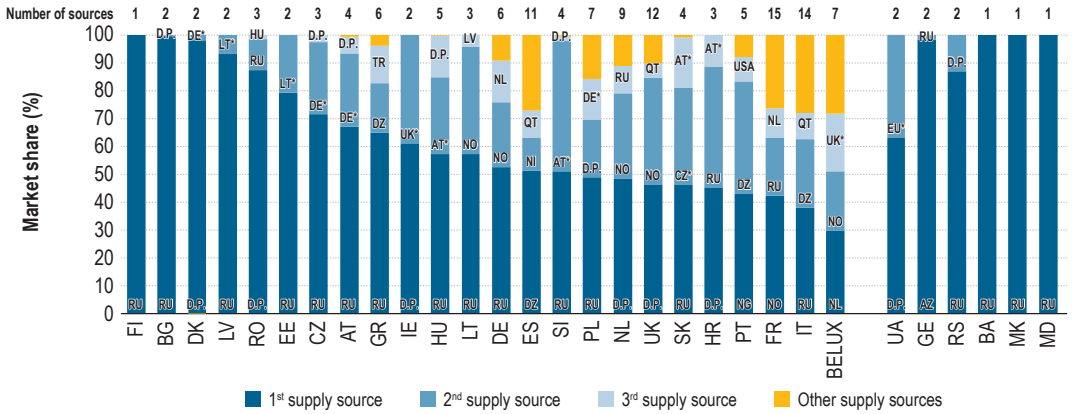
118 Sourcing of gas in individual MSs' markets ranges from complete or almost complete dependence on one external supply source (Finland and Bulgaria[50]), to predominant reliance on domestic production (Romania and Denmark), as Figure 13 shows. Most MSs' gas markets, however, fall between these two extremes: LNG importing gas markets tend to boast the highest number of distinct geographical origins of gas supply; NWE gas markets have the most balanced supply portfolio; and CEE markets are supplied by a combination of Russian imports and EU hub deliveries. Diversity of supply was also assessed for the EnC CPs. As Figure 13 shows, apart from Ukraine (which in 2018 was fully supplied by domestic production and gas sourced at EU hubs) EnC CPs have a high reliance on one external supplier.

48 Transparent trading venues refer to organised wholesale market places, either exchanges or OTC deals facilitated via brokers. AGTM Annex 3 further clarifies the metrics methodology and provides a definition of technical concepts.

49 Due to the relevant data being available only per MS, it is not feasible to calculate the metrics for the two German and French hubs in a disaggregated fashion.

50 Bulgaria is procuring US LNG via Greece in 2019 which would end its dependence on one supply source.

Figure 13: Estimated number and diversity of supply sources in terms of the geographical origin of gas in selected MSs and EnC CPs– 2018 - % of actual volumes purchased[51]



Source: ACER calculation based on Eurostat, IEA, British Petroleum and EnC Secretariat data.

Note: D.P stands for domestic production. The asterisk refers to MSs with liquid hubs where gas is thought to have been purchased. For Denmark, the share of domestic production also includes the Norwegian offshore fields that are part of the Danish upstream network. Due to the merger of the Danish and Swedish market areas in 2019, GTM metrics were not assessed for Sweden.

119 A further sign of healthy competition is that none of the distinct supply sources have too sizeable a market share. In order better to gauge this competition aspect, the upstream Herfindahl-Hirschmann Index was assessed for individual hubs. The HHI assessment is more detailed, as it looks into gas producing companies' theoretical market shares. Finally, the residual supply index (RSI) gauges the dependency of a MS or hub on its main supplier by analysing whether sufficient alternative suppliers are available, so that the market does not overly rely on its largest supplier to meet its demand.

120 Figure 14 shows the results of the three upstream market health metrics: number of supply sources, RSI and HHI. It illustrates that the wholesale markets in the Netherlands, the UK, France and BeLux meet all three AGTM market health benchmarks, followed by gas hubs in Italy and Spain, whose upstream market HHI is relatively close to the AGTM recommended threshold[52].

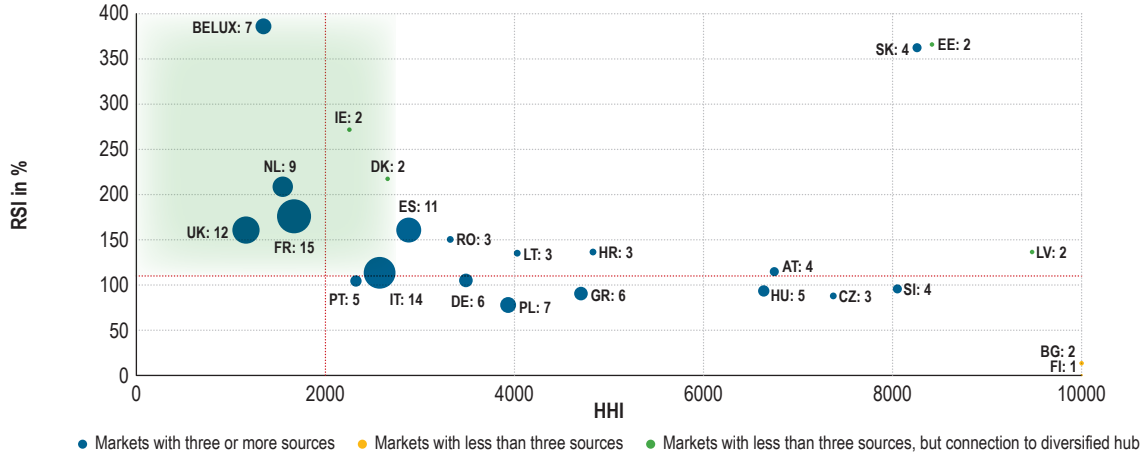
121 *Healthy* upstream market concentration is the benchmark that most MSs hubs fail to meet[53]. However, MSs that either host, or are sufficiently interconnected to, well-functioning hubs, those with less concentrated domestic production and/or those that benefit from a flexible supply source, i.e. LNG, exhibit lower HHI values.

51 The metric looks at the geographical origin of the sourced gas and not at the number of distinct interconnection capabilities. At selected MSs both figures may differ.

52 The use of estimates suggests that 'target levels' cannot be taken at face value.

53 Transparency of information on market shares of upstream producers is limited in many markets. Also, the assumptions made may affect the calculations, so the results have to be treated with some caution. The utilisation of REMIT data in the future will provide more precision in the assessment. Therefore, this MMR does not attempt to interpret the thresholds of the AGTM by the letter.

Figure 14: Overview of EU MSs AGTM market health metrics – 2018



Source: ACER calculation based on ENTSOG capacity data, Eurostat and NRAs.

Note: Y-axis – measures the percentage of MSs demand that can be met without an entry capacity reliant on the largest supply origin. RSI gauges pipeline, LNG and domestic production supply capacity not controlled by the largest supplier. It is intended to quantify the competitive strength of the market. RSI disregards storage, but accounts for transits. The feasibility of physical volumes being acquirable is not evaluated, which could result in an overestimate of the RSI. The HHI value – X-axis – measures the concentration of companies on the supply side (see MMR 2015 Annex 1 for further details on the approach). The bubble size represents the number of distinct supply origin sources. The lower 2018 RSI for the Czech Republic is explained by the exclusion of some point-to-point conditional capacities on the German border from the CZ residual supply.

122 As Figure 14 also shows, most MSs have sufficient residual supply import capacities[54], which suggests that, notwithstanding high concentration levels, the largest suppliers' powers to set prices are curtailed by prices at which other connected suppliers are willing to sell to the market. However, for those MSs where the RSI is below the threshold – i.e., Bulgaria, Finland and to a lesser extent Greece, Hungary, Poland and Slovenia – the largest supplier is pivotal. This means that competitors cannot fully replace this player and, as such, the latter could exert market power over price formation.

123 Modest LNG imports, declining indigenous production, the need to honour legacy contracts and the rise in imports from Russia were the main aspects impacting the 2018 results. It is an instructive exercise to compare supply-side concentration levels with the market shares of final gas sales by downstream company[55]. High supply-side concentration can still be compatible with competitive retail markets, particularly if a dynamic midstream market, sustained by well-functioning hubs, allows end-suppliers to source their gas in a competitive manner.

124 Overall, the results for the three market health metrics are closely interrelated, as they measure interdependent aspects. Moreover, they are also strongly linked to the metrics gauging the quality of hubs' functioning, which will be presented in the next Section. Market health metrics reveal structural aspects that influence the way in which gas wholesale markets function.

3.2 Gas hub categorisation

125 Figure i in the executive summary presented the 2018 classification of gas hubs. The classification reflects the results of the analysis of the AGTM *market participant's needs* metrics. While there are notable positive developments in, *inter alia*, Austria, Hungary, Italy and Spain, those MSs where a trading venue with a transparent price mechanism is either absent or not visible during many trading days of the year continue to fall behind better performers. The classification sees the following changes compared to last year; Slovakia has moved back into the *illiquid* hubs after being classified as an *emerging hub* for the past two MMR assessments and Spain moved into the advanced category.

54 MSs whose gas transmission system accommodates significant transit flows – e.g. Slovakia, Belgium, the Netherlands and the Czech Republic – perform the best for this metric. In addition, MSs with significant LNG regasification capacities relative to current demand, like Spain, the UK and Greece, also score high for the RSI.

55 See, for example, MMR 2015 executive summary Figure 4.

126 The values of the metrics that measure the performance of hubs warrant TTF and NBP to be placed into a separate group called established hubs. The breadth and depth of these gas hubs, on forward markets, for example, is such that they are far ahead of any other European hub. Within this category, TTF continues to outpace NBP. However, both TTF and NBP are still some distance from the most developed gas hub in the world, i.e. Henry Hub (for example, the churn rate is around 90 for Henry Hub, 50 for TTF and 22 for NBP), let alone the level of sophistication of oil hubs. The regulatory uncertainty created by the pending Brexit continues to weigh on NBP. Other factors contributing to the lower liquidity levels are, *inter alia*, the loss of the Rough storage facility and its associated storage trading as well as the higher attractiveness of TTF as a hub for hedging activities. This also negatively impacts the ZEE hub which 'sits' on the Interconnector with Great Britain.

127 Several hubs in the advanced category, like the Italian, Spanish and Austrian hubs, showed notable improvements. The Austrian hub is the reference market for Central and parts of Eastern Europe, helped by its strategic position and developed hub, for example in terms of product offering. Liquidity progressed at PSV, which is testimony of the Italian hub becoming more mature. The introduction of selected market-oriented measures like changes in the storage obligation regulation, the storage operator offering products aimed at increasing flexibility or the use of market makers explain the trend. The Spanish hub made important progress. Its price formation is getting more closely linked to NWE hub price signals. In addition, the regulator forced the TSO to procure gas for decompressor stations on the DA market. The main differentiator of the advanced hubs with established hubs is their less developed forward markets.

128 In the group of markets with lower liquidity, the Hungarian hub's liquidity is gradually increasing driven by its increasing role in transit. Ukrainian buyers took advantage of the more competitive tariffs at the border by transiting gas from Hungary.

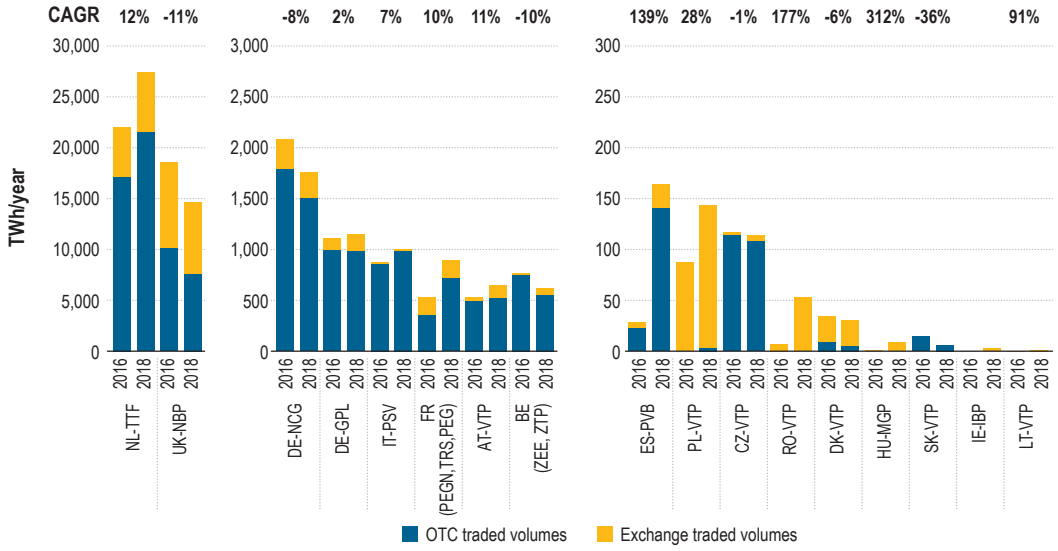
129 The liquidity analysis of gas hubs draws heavily on data reported under REMIT. Therefore, the relevant metrics could only be calculated for those market areas where gas is traded on transparent trading venues, which is not yet the case for all gas market areas in the EU. In most of these cases a transparent trading venue is still absent or too embryonic. This indicates that further steps towards implementing transparent gas trading are needed in those areas. However, the lack of inclusion in this AGTM assessment does not necessarily mean that some form of market is not developing. For example, the AGTM metrics for Slovenia could not be processed, as transactional activity is developing on the TSO's balancing platform, which is out of scope of REMIT reporting. However, this could be embryonic for further trading activity. Additionally, market development and functioning is hindered by measures taken that restrict free gas trading (Romania) or anti-trust concerns (Bulgaria).

130 The AGTM recommends market integration as a way of addressing the weak performance of individual markets and a number of initiatives are under way or have been announced in the past, as reported in previous MMRs. Positive in this respect is that in early 2019, the small Swedish balancing zone merged with the Danish Balancing zone, effectively taking over Danish rules. The Agency is of the opinion that the number of hubs and their location is a decision which should be driven by the market.

3.3 Overview of trading activity at EU gas hubs

131 Total EU hub traded volumes were at a record high in 2018 – around 7% more gas changed hands at transparent trading platforms compared to 2017, and around 3% more than in 2016, which had been the previous record year. The growth of traded volumes at the largest gas hub in the EU, TTF, was particularly impressive, as volumes increased by more than 25% compared with 2017 and accounted for over 90% of the total hub traded volumes increase in the EU. TTF, where market participants traded more than half of all the gas traded at EU hubs in 2018, has been growing by virtue of its growing role as the preeminent hub for transactions beyond the spot timeframe and attracting the bulk of forward trading activity in the EU.

Figure 15: Traded volumes at EU hubs (TWh/year and CAGR) – 2016 to 2018 (three scales)



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

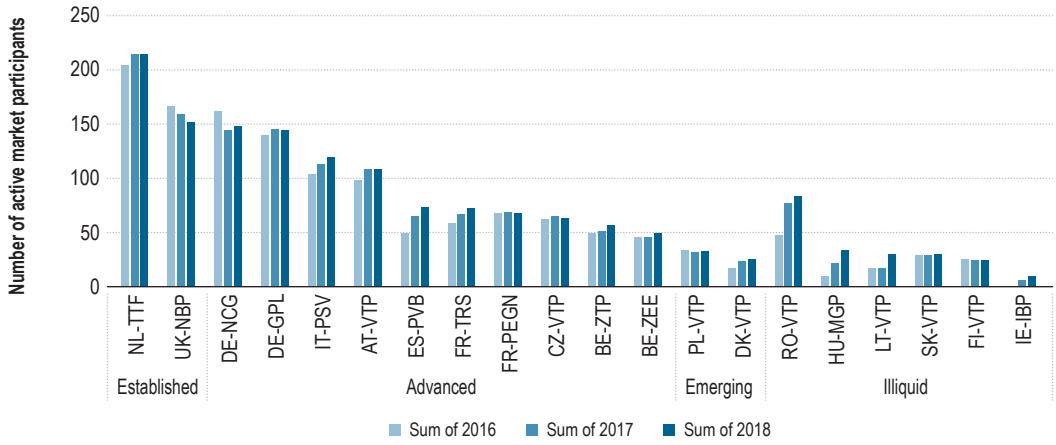
Note: Statistics refer only to volumes traded via transparent market platforms with a price reference and some kind of product standardisation; OTC refers to physically settled volumes traded among parties via brokers – with either the parties managing credit risk or trading being cleared by the broker; exchange execution denotes those volumes supervised and cleared by an organised central market operator. In some markets, sizeable volumes are traded, although not on transparent market platforms. These bilateral deals or swaps can also lack a price reference.

132 There are substantial differences in volumes traded at different EU hubs as Figure 15 shows. The amount of gas traded at TTF or NBP is larger by a factor of at least ten with respect to any of the advanced hub's traded volumes and larger by a factor of one hundred when compared to any of the emerging or illiquid hub's traded volumes.

133 The traded volume CAGR from 2016 to 2018 shows that the fastest growing hubs in this period were the Hungarian, Spanish and Lithuanian hubs. In absolute terms, however, both the Lithuanian and Hungarian hubs' additional traded volumes were relatively small. The Spanish PVB, on the other hand, was also amongst the hubs where traded volumes increased most in absolute terms. Other hubs with substantially increased absolute traded volumes in this period were PEGN, PSV, AVTP, ZTP and TTF, where, as mentioned previously, the majority of the growth of EU hub traded volumes took place.

134 The biggest decline in traded volumes took place at NBP, at the closely related Belgian ZEE and at the German NCG. In relative terms, a significant decline took place at the Slovak hub, which, together with the growth at the Hungarian MGP, resulted in the latter overtaking the former in terms of traded volumes. At some hubs, the changes in traded volumes coincided with businesses either entering or leaving the market; compared to 2016, the Hungarian, Spanish, Italian and Lithuanian hubs were among the hubs with most new active market participants, whereas NBP and NCG were hubs with the greatest decrease in the number of active market participants. Figure 16 shows the estimated evolution of active market participants at EU hubs.

Figure 16: Estimated number of active market participants – 2016 to 2018



Source: ACER calculation based on REMIT data.

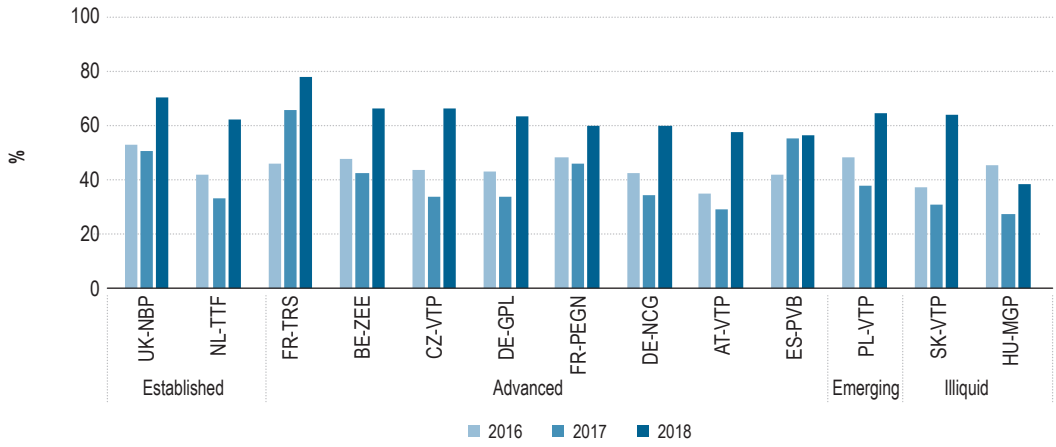
Note: Estimated based on registered users with at least one trade of standard contract for delivery at relevant VTP during the year.

135 There were more than six hundred market participants active at EU gas hubs in 2018, an increase of more than 10% when compared with 2016. Unsurprisingly, the hub with the largest number of active market participants is TTF, with a third of all market participants active at EU hubs also active at the TTF. The criteria used for defining a market participant as active is that it concluded at least one trade during the year. It is clear that the use of a more continuous trading pattern as criteria would result in a shaper contrast between more liquid and less liquid hubs in number of active market participants.

DRIVERS OF GROWING HUB TRADED VOLUMES IN 2018

136 Higher spot price volatility was one of the short-term factors that influenced hub trade of natural gas in 2018. The average volatility of hub spot prices was significantly higher than in 2017 at most of the assessed hubs as Figure 17 shows. Factors influencing volatility were the unforeseen cold weather spell at the end of winter 2018, the greater influence of global LNG market dynamics on EU hub's prices and the relative loss of supply flexibility at the key reference European markets TTF and NBP (Groningen and Rough facilities, respectively).

Figure 17: DA volatility at selected EU hubs, 2016 – 2018 (yearly average)



Source: ACER calculation based on Platts and ICIS Heren.

Notes: To conduct the volatility analysis, the logarithmic returns of daily gas hub settlement prices are first gauged. The standard deviation of returns is then calculated and multiplied by the square root of total trading days in a year. The value is expressed as a percentage.

137 The relationship between volatility and traded volumes is not linear, and likely affects hubs with varying levels of liquidity in a dissimilar manner. However, events that affect fundamentals, like unforeseen changes in demand, will attract market participants with physical exposure to trade at hubs. Furthermore, market participants without physical exposure could have greater incentives to speculate in periods of higher volatility, as there are more possibilities of making a larger gain in those periods.

138 Changes in fundamentals of future supply were also significant drivers of increased hub trading activity. For instance, the announcement of new production caps at the Groningen field in the Netherlands resulted in shippers adjusting their TTF forward positions. There was also significant trading activity following the cold weather spell that depleted gas storage sites throughout Europe, as shippers procured additional volumes in order to refill storage stocks.

139 LNG players using TTF for risk management could be another driver of increased trading activity, as various reports are indicating that major LNG producers and LNG contract aggregators are becoming more active at the Dutch hub, sometimes at the expense of the previously favoured NBP. The liquidity of TTF enables them to hedge, or sell forward, any uncontracted volumes, which they can then buy back at a later stage if delivering LNG to a different market proves more profitable.

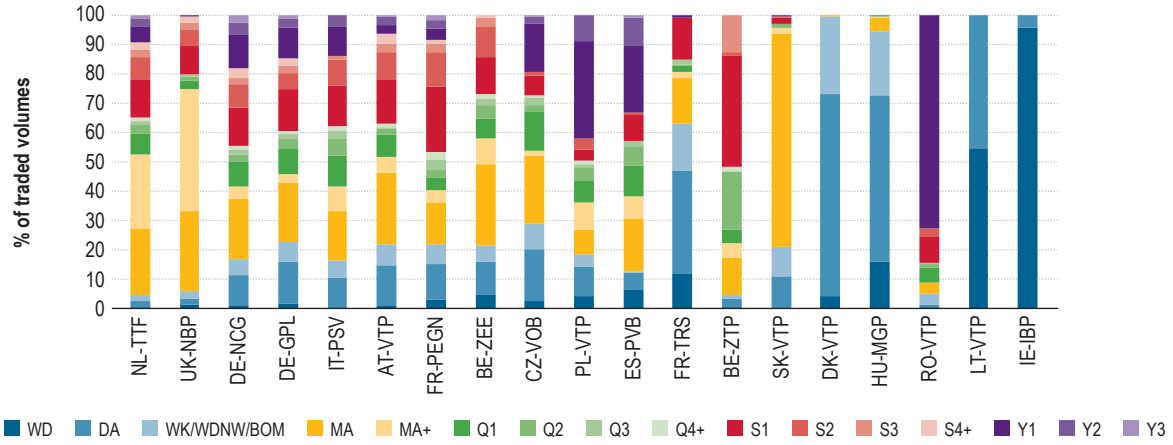
140 Changes in long-term gas contracts price indexation from oil-price based to gas hub-price based is a trend that continued in 2018, and is likely having a positive impact on hub traded volumes, as it enables both contracting parties to manage their LTC-related risk at the hub more easily.

141 Implementation of the Gas Balancing Network Code is likely one of the drivers of growing spot liquidity at some of the previously underperforming gas hubs, including the Italian PSV, Spanish PVB and Hungarian MGP. See Section 4.6 for a detailed analysis of market effects of the Balancing Network Code.

BREAKDOWN OF HUB TRADED VOLUMES

142 Figure 18 shows the relative importance of different types of products traded by market participants at EU hubs in 2018. It shows that spot products (DA, WD, BoM, etc.) make up a relatively small share of overall traded volumes at TTF, NBP and ZTP. At other EU gas hubs, spot market products represent between 10% and 100% of traded volumes.

Figure 18: Breakdown of traded volumes per product at EU hubs – 2018 – % of traded volumes



Source: ACER calculation based on REMIT data. Values consist of OTC broker and exchange trades.

Notes: TTF and NBP data based on OTC trades only. Product acronyms stand for: Y years, S seasons, Q quarters, MA month ahead, WK/BOM week or balance of month. DA and WD refer to day-ahead and within-day respectively. The number following the acronym denotes the succeeding trading period (e.g. Q3 denotes the next third quarter after trade conclusion. Quarters comprise strips of three individual and consecutive contract months, from either Jan-Mar, Apr-Jun, Jul-Sep or Oct-Dec.)

143 Medium-duration contracts (such as month, quarter and season contract types) represent the largest share of traded volumes at EU hubs, with the exception of some hubs where only spot products are traded. Long-duration products (or yearly contracts) have a large share of traded volumes at the Romanian, Spanish and Polish hubs, a result of local market specificities and legal obligations, but make up a relatively small share of traded volumes elsewhere. Furthermore, yearly products are not particularly liquid at the Romanian, Spanish and Polish hubs, but are rather transacted on few occasions in big volumes.

3.4 Liquidity and competition at EU hubs spot, prompt and forward markets

144 As mentioned in the introduction to this Chapter, a central tenet of the AGTM is that the European internal gas market should be comprised of liquid, competitive gas hubs. This Sub-section presents the results of a number of AGTM indicators with the intention of gauging liquidity and concentration at gas hubs. Results for hub's spot (DA), prompt (MA) and forward (beyond MA) markets are presented in turn. Liquidity of the spot and prompt markets has been assessed by indicators measuring trading frequency, the bid-ask spread and the size of the order book. The liquidity of the forward markets has been gauged by indicators measuring the trading and order book horizon. Competition at hubs' spot, prompt and forward markets has been gauged with an indicator measuring the concentration of market participants concluding trades in the respective different timeframes.

SPOT MARKETS

145 EU hubs spot markets have the highest trading frequency of any traded timeframe. At some EU gas hubs, market participants only trade spot gas products and for most hubs, spot product trades represent the majority of hub trades, if usually not the majority of traded volumes.

146 In 2018, the average number of trades on the spot market increased at the majority of hubs when compared with 2017. The exception to this trend were NBP, ZEE, and the Czech, Polish and Slovak hubs. Market participants were most active on the TTF hub, where more than 1000 DA trades were concluded in an average trading session[56] in 2018. In a positive development compared with last year's assessment, in addition to TTF, both German hubs met the AGTM threshold of an average of 420 DA trades per trading session in 2018. Furthermore, NBP, the Austrian, French PEGN and Italian hub's spot trading frequency was also substantial, with more than 200 trades concluded per day on average. In the group of advanced hubs, the Belgian ZTP stood out in terms of relative growth of the number of DA trades, indicating that quite some spot trading activity has migrated there from the physical ZEE hub, which is losing volumes. The growth of spot trading activity at the Spanish PVB was also impressive, with the number of trades more than doubling compared with 2017. Section 4.6 further shows the increase in spot trades in those hubs linked to the implementation of the Balancing Network Code.

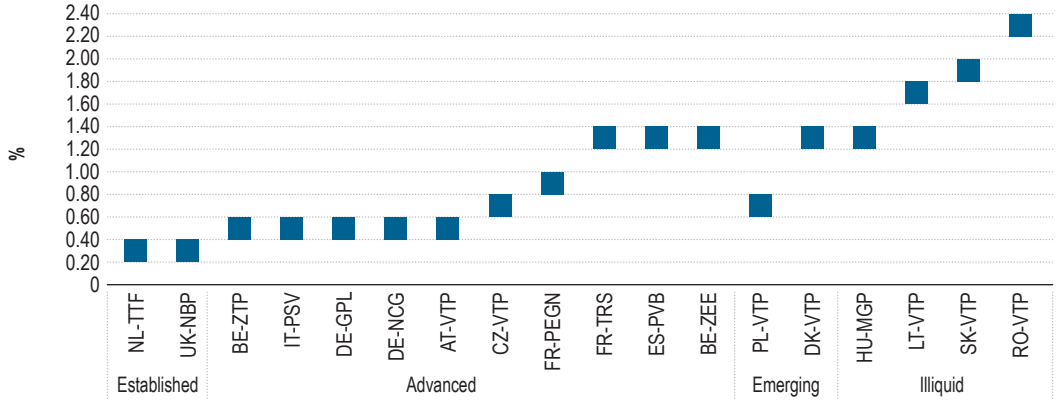
147 In the group of emerging hubs (PL and DK) spot trading frequency is quite homogeneous, with market participants concluding around 30-50 trades per day at each of the hubs.

148 In the group of illiquid hubs, which includes a number of hubs for which AGTM metrics cannot be assessed due to either the absence of a virtual hub or the absence of liquidity at the hub, there were some positive signs of market activity. There was, for instance, a greater number of spot trades in the Baltics and Romania; and the introduction of a virtual hub in Ireland at the end of 2017 resulted in the development of some spot liquidity during 2018.

149 The bid–ask spread, presented in Figure 19 for the different EU hubs, 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 one measure of the size of the transaction cost and of liquidity of hubs. The lower the bid-ask spread, the lower the transaction costs and the higher the liquidity.

56 A trading session is the primary trading hours for a given asset and locale, i.e. a single day of business in the market.

Figure 19: Bid-ask spread of EU hubs spot markets (percentage of DA ask price shown as a range) – 2018



Source: ACER calculation based on REMIT data.

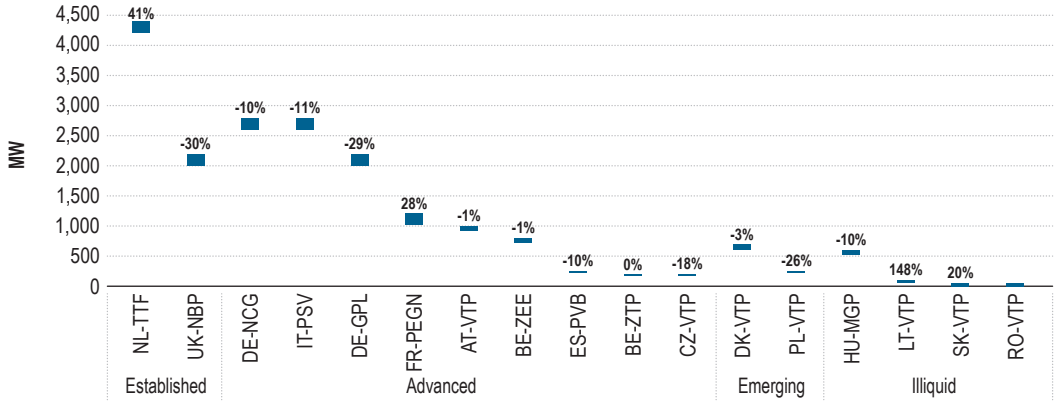
Note: Bid-ask spread is a measure of the average difference between the lowest ask-price and the highest bid-price expressed as a percentage of the highest bid-price across the day. Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

150 At most hubs, the DA products' bid-ask spread was narrower than in the previous two years. This improvement means that besides TTF and NBP, also ZTP, PSV, GPL, NCG and AVTP were all in line or close to being in line with the AGTM recommended threshold of 0.4% of the bid price (as the bid-ask spread is measured relative to the commodity price, the improvement can be partially attributed to higher gas prices in 2018[57]).

151 Compared with 2017, the bid-ask spread narrowed the most at the Belgian ZTP, Czech VOB and Hungarian MGP, though in the case of the latter, it was still relatively high at more than one per cent of the bid price. The exceptions to the positive developments were the Lithuanian hub, ZEE, PEGN and the Slovak hub, where the average DA bid-ask spread widened.

152 Compared to 2017, the already substantial TTF order book continued to grow as Figure 20 shows. The order book volumes metric refers to the availability of orders at any time. Besides TTF, both German hubs and the Italian PSV are all in line with the AGTM recommended threshold of 2000 MW of gas available in the order book. The sizeable demand at these hubs, the associated balancing needs of market participants and the Balancing Network Code stipulation that market participants have primary responsibility for balancing their positions could explain this evolution.

Figure 20: Available Spot order book volumes – MW (lower of bid- and ask-sides during the day for DA products, OTC and exchange aggregated shown as a range; yoy change) – 2018



Source: ACER calculation based on REMIT data.

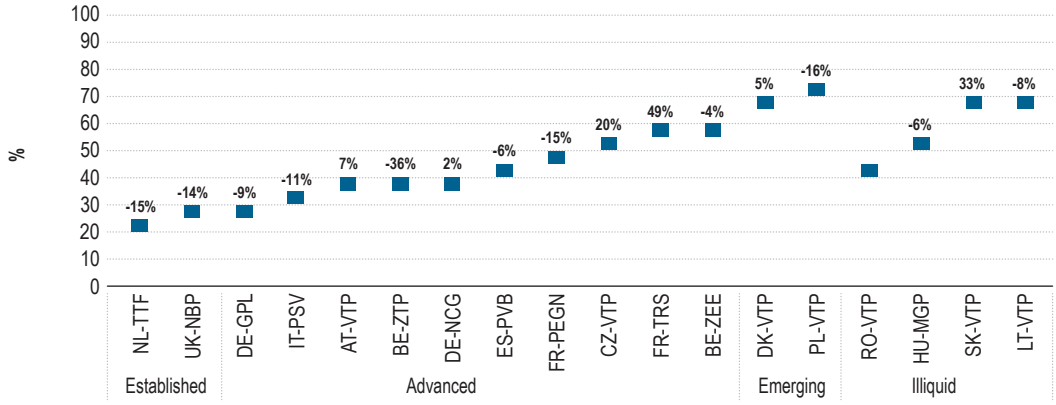
Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed. Hubs with no yoy percentage were not previously assessed (ROVTP) or cannot be compared like for like with last year's assessment (NBP).

57 E.g. A bid-ask spread of 0.1 euros/MWh represents 1% of the commodity price at 10 euros/MWh but 0.5% of a commodity price of 20 euros/MWh.

153 The spot order book size at AVTP, PEGN, ZEE and also at the Hungarian and Danish hubs was also substantial, although below the AGTM benchmark. Market makers play an important role in many hubs in building order books during the development towards a more mature hub.

154 Figure 21 shows that in 2018, spot market competition was relatively healthy at most EU gas hubs; however, the Polish, Danish, Slovak and Lithuanian hubs were assessed to have relatively high concentration levels.

Figure 21: Spot market concentration – CR3 (average CR3 shown as a range for concluded DA trades, yoy change) – 2018



Source: ACER calculation based on REMIT.

Notes: 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. Intragroup trades included. Hubs with no yoy percentage were not previously assessed.

155 In the group of established and advanced hubs, spot market competition seems to have improved in 2018 when compared with 2017 for most hubs.

PROMPT MARKETS

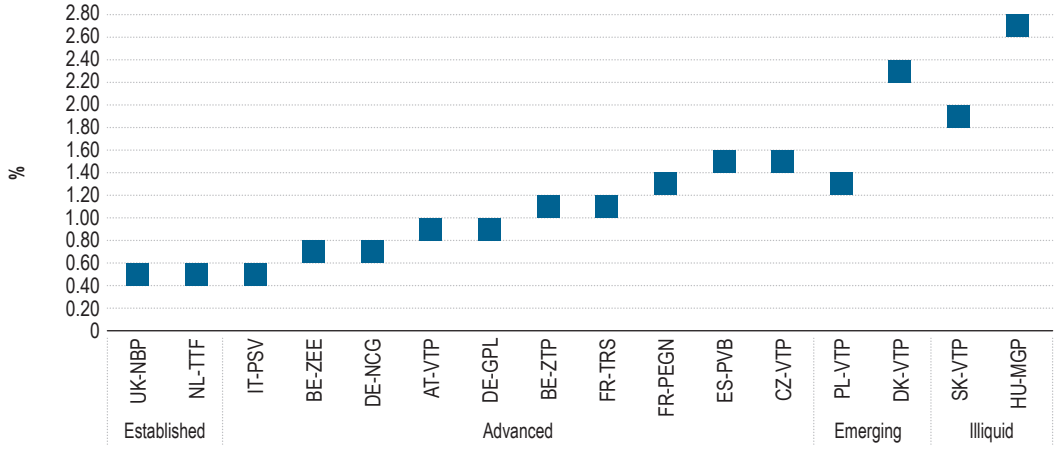
156 Trading activity on the prompt (or near curve) markets, as measured by the daily average number of MA trades, is much less evenly distributed among EU hubs than that on the DA market. Most of the prompt trading activity is concentrated at TTF and NBP, as these two hubs attract both market participants with physical exposures at other EU hubs looking for hedging opportunities and traders looking to speculate on gas price movements in the EU. The division between NBP and TTF and other EU hubs had become even starker in 2018, as market participants concluded fewer MA transactions outside of NBP and TTF than in the previous years.

157 In 2018, more than 1200 MA trades were concluded on an average trading session at TTF or NBP, which is comparable to the result for 2017. The front month is one of the crucial traded timeframes for the two established hubs, as unlike at other EU gas hubs, market participants conclude more prompt than spot trades on an average trading day.

158 At other hubs, there was on average 60 or less MA trades per trading session: NCG, GPL, AVTP, PSV, the Polish hub, PVB and PEGN were the hubs with most prompt trading activity outside of the established hubs.

159 The bid-ask spread for the MA product narrowed or remained similar to that assessed for 2017 at most EU hubs, even as prompt trading activity outside of TTF and NBP contracted. As mentioned previously, one of the reasons for relatively narrower bid-ask spreads is likely the higher natural gas prices in 2018 when compared with 2017. However, multiple factors influence the bid-ask spread, *inter alia*, the average volumes transacted versus the number of transactions, and the order book availability versus number of concluded trades.

Figure 22: Front month bid ask spread (best of either exchange or OTC, percentage of MA ask price shown as range) – 2018



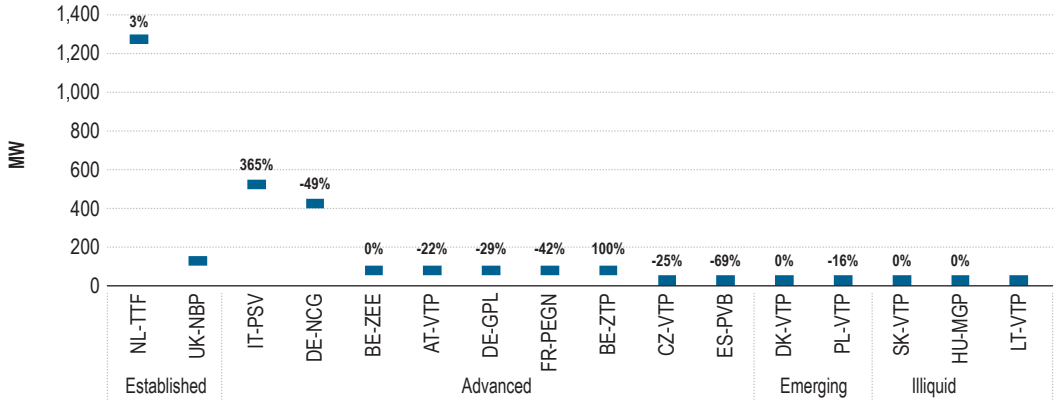
Source: ACER calculation based on REMIT data.

Note: Bid-ask spread is a measure of the average difference between the lowest ask-price and the highest bid-price expressed as a percentage of the highest bid-price across the day. The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

160 Figure 22 shows that the tightest MA bid-ask spreads were assessed at TTF, NBP and PSV. Other hubs' average MA bid-ask spreads were considerably higher, with those at NCG and the Polish hub widening the most compared with 2017. Hubs with a positive trend of narrowing bid ask spreads include ZTP, PVB and the Slovak, Danish and Hungarian hubs.

161 The prompt order book is in line with the AGTM threshold at TTF and, after expanding considerably in 2018, at the Italian PSV. The German NCG is also close to the AGTM recommended threshold of 470 MW. Other EU hubs' MA order books were considerably shallower as can be seen in Figure 23.

Figure 23: Available Prompt order book volumes – MW (average bid and ask-sides during the day for month-ahead products shown as a range, OTC and exchange aggregated, yoy change) – 2018

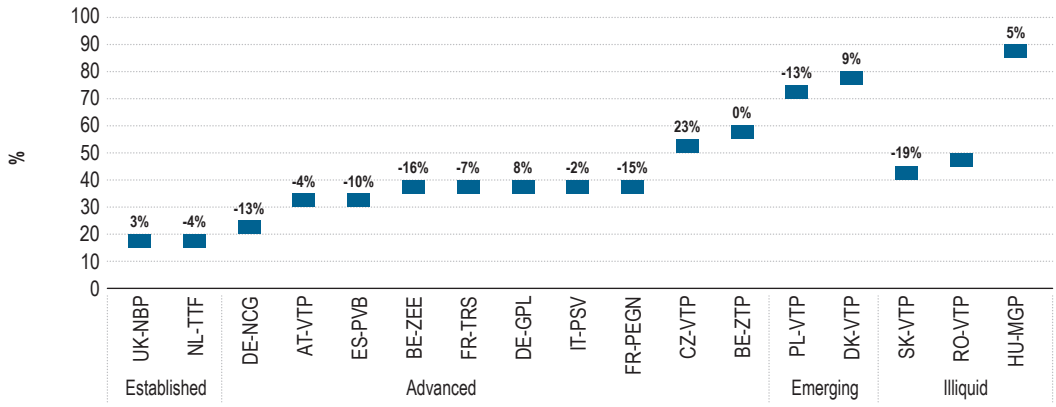


Source: ACER calculation based on REMIT data.

Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed. Hubs with no yoy percentage were not previously assessed (ROVTP) or cannot be compared like for like with last year's assessment (NBP).

162 Even as EU prompt market activity has been migrating to the two established hubs over the past couple of years, prompt trading activity that has remained outside of TTF and NBP has taken place within a context of increasing competition. In other words, when compared with past years, prompt market's concentration of trades was lower at the majority of EU hubs in 2018.

Figure 24: Prompt market concentration – CR3 (average CR3 for concluded MA trades shown as a range, yoy change) – 2018



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. Intragroup trades included. Hubs with no yoy percentage were not previously assessed.

163 Figure 24 shows that the most competitive prompt markets in 2018 were those associated with the NBP and TTF hubs, where the average trading session's CR3 (which measures the market share of the three largest market participants on the buying and selling side of a trading session) was below 20% in 2018.

164 After decreasing over the past few years, concentration at most advanced hubs was below 40% when measured by CR3 in 2018. The exceptions were the Czech hub, where concentration increased noticeably compared to 2017, and the Belgian ZTP, which continued to have the most concentrated prompt market in the group of advanced and established hubs.

165 Of all the assessed hubs, the most concentrated prompt markets were those at the Polish, Danish and Hungarian hubs, where, with the assessed CR3 above 70% on average, there is evidence that only a handful of market participants dominated trade on the prompt market.

FORWARD MARKETS

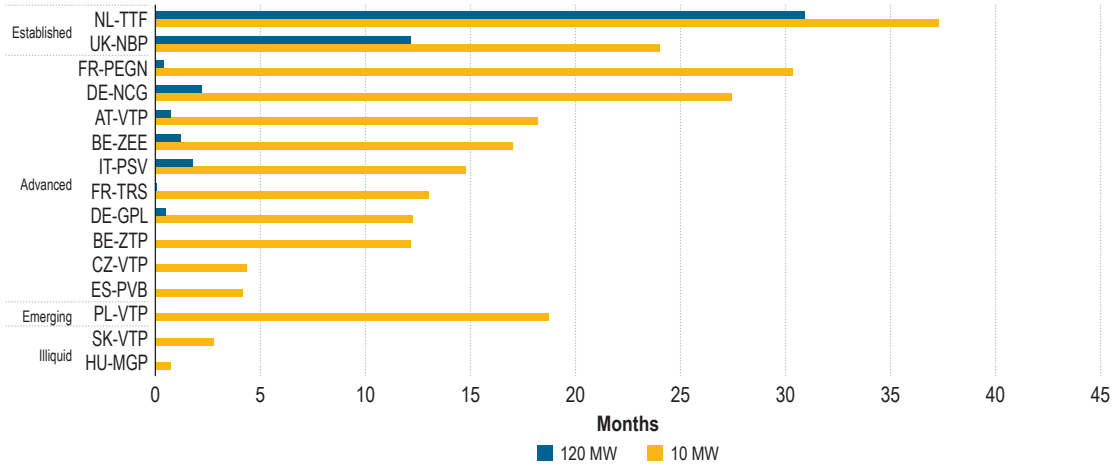
166 The forward markets with the highest liquidity in the EU are those at TTF and NBP. In fact, the analysis of the hubs' trading horizon reveals that frequent trading beyond the season-ahead takes place almost exclusively at TTF and NBP. However, this does not mean that forward products are not traded at other hubs – data shows that, on average, at least a couple of forward products change hands at most advanced and emerging hubs in every trading session.

167 The greatest expansion of trading horizon in 2018 took place at TTF, where market participants now frequently trade gas for delivery beyond three years in the future. The trading horizons of NBP (28+ months into the future) and NCG (8+ months into the future) also expanded substantially, though this was preceded by a contraction of forward trading horizon in 2017. At other hubs, the trading horizon was either comparable or slightly greater than in 2017, notably, at least in relative terms, at the Polish and Spanish hubs. However, it should be noted that bar NBP and TTF, no hubs' trading horizon comes close to the AGTM recommended threshold of eight daily trades for products delivering at least 22 months into the future from the time of the trade.

168 When the criteria of the trading horizon is lowered to two daily trades, a somewhat different picture of forward trading at EU hubs emerges. TTF and NBP are not affected much by the change in criterion but what is revealed is that at most advanced and emerging hubs forward products are traded, though at a much lower frequency than at established hubs.

169 In 2018, of the assessed hubs' order books only TTF had a sizeable forward order book horizon. As Figure 25 shows, a number of other hubs have volumes available in their order books on the far curve; however, the available volumes are much smaller than those at TTF.

Figure 25: Order book horizon – months (lower of either the bid or the offer side, 2018)

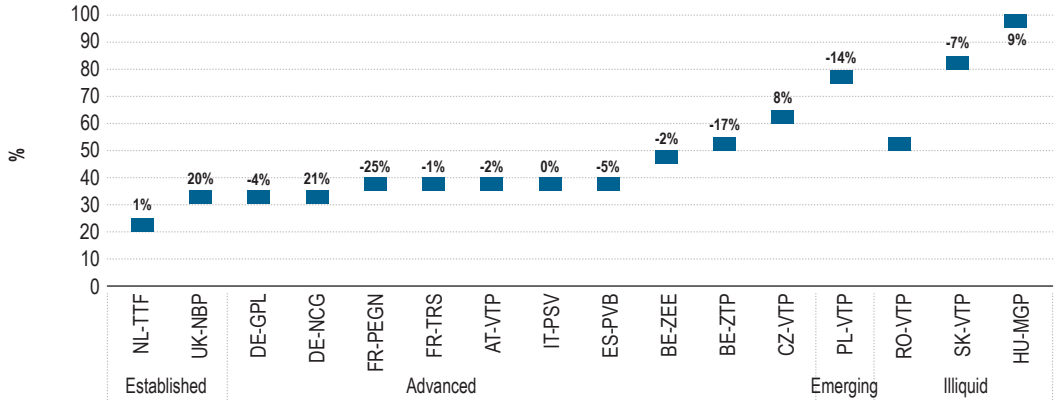


Source: ACER calculation based on REMIT data.

Note: The order book of NBP refers to OTC only; exchange order books could not be reliably assessed.

170 Unlike the assessment of competition at hubs' spot and prompt markets, where the analyses are based only on the DA and MA products, the assessment of competition of the forward markets takes into account a basket of forward products.

Figure 26: Forward market concentration – CR3 (average CR3 of trades concluded for a basket of FW products shown as a range, relative yoy change) – 2018



Source: ACER calculation based on REMIT.

Notes: 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. Intragroup trades included. Hubs with no yoy percentage were not previously assessed.

171 Figure 26 shows that in 2018, the most competitive EU gas forward markets continued to be those associated with the TTF and NBP hubs, even as in the case of the latter concentration increased over recent years. Most *advanced* hubs' forward market competition was relatively strong, as only the two Belgian hubs' and the Czech hub's CR3 were assessed above 40%. Concentration at emerging and *illiquid* hubs' forward markets is considerably higher.

3.5 Correlation and convergence of prices of gas traded at EU hubs

172 In addition to liquidity and trade competition at virtual hubs, a crucial component of the AGTM is the idea of market integration, defined as gas moving between market areas to virtual hubs where it is most highly valued by gas market participants. This implies that the prices of gas at different virtual hubs would not only be correlated, but would converge over time, to the extent allowed by the efficient use of transportation capacity.

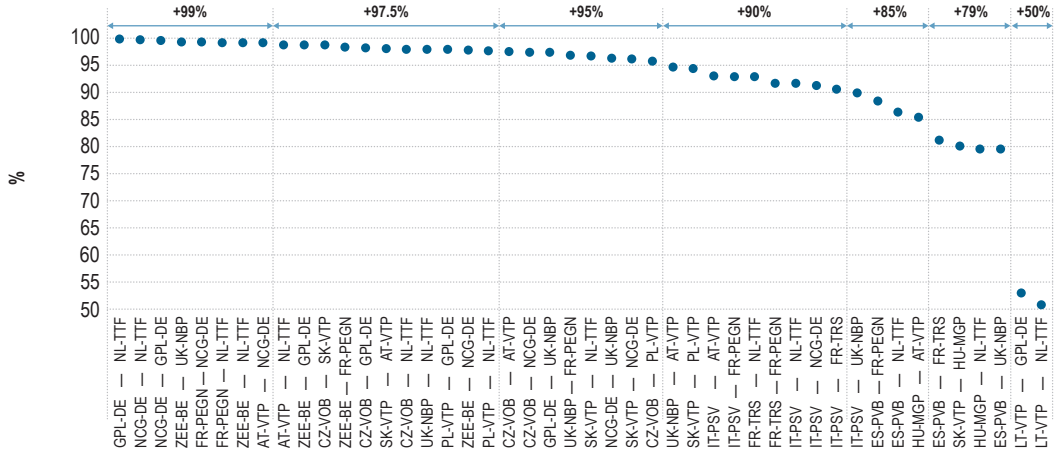
173 In order for this process to take place, liquidity at gas hubs is key, as it means that reliable price signals emerge, allowing market participants to direct gas flows from low- to high- price hubs.

174 As Section 3.4 showed, liquidity is broadest at a hub's spot markets; therefore, this Sub-section uses the hub's spot market prices as the basis for analysing market integration of EU gas hubs[58]. However, as was described in Section 3.2, hubs do not yet cover the entirety of the EU's internal gas market and not all hubs are liquid enough to give a clear daily gas price signal. In other words, the market integration vision of the AGTM is yet to be fully realised; however, as will be shown in the remainder of this Chapter, gas hubs where the majority of EU gas consumption takes place can be described as highly integrated.

175 As the EU's IGM can generally be characterised as well interconnected, with ample cross border capacity available to market participants between most gas hubs, spot prices at hubs are strongly interlinked and correlated in most cases, as Figure 27 shows.

176 High correlation between EU gas hub's spot prices, in particular between TTF's and other EU hubs' spot prices, is one of the reasons behind the emergence of TTF as the venue for forward price and supply hedging for market participants with physical positions throughout the EU. High price correlation means that market participants can use TTF as a venue to hedge their exposures at other hubs by approximation (proxy hedging). Positions opened on TTF can then be unwound before delivery and replaced with either buy or sell positions in hubs where those market participants actually have their physical position. The high price correlation between hubs means that risks associated with proxy hedging strategies are relatively low.

Figure 27: Correlation of selected hub spot prices – 2018



Source: ACER calculation based on Platts and ICIS Heren.

Note: Correlation measured as Pearson coefficient. The Pearson correlation coefficient is a measure of the linear correlation between two variables X and Y. In this example of X and Y are closing prices of gas for delivery on the next day at two EU gas hubs. 100% is total positive linear correlation, 0% is no linear correlation, and −100% is total negative linear correlation.

58 While not presented here, the price convergence of the month-ahead products is similar to the convergence of the day-ahead products. However, the price difference tends to be more stable as short-term peak variations have a lower impact.

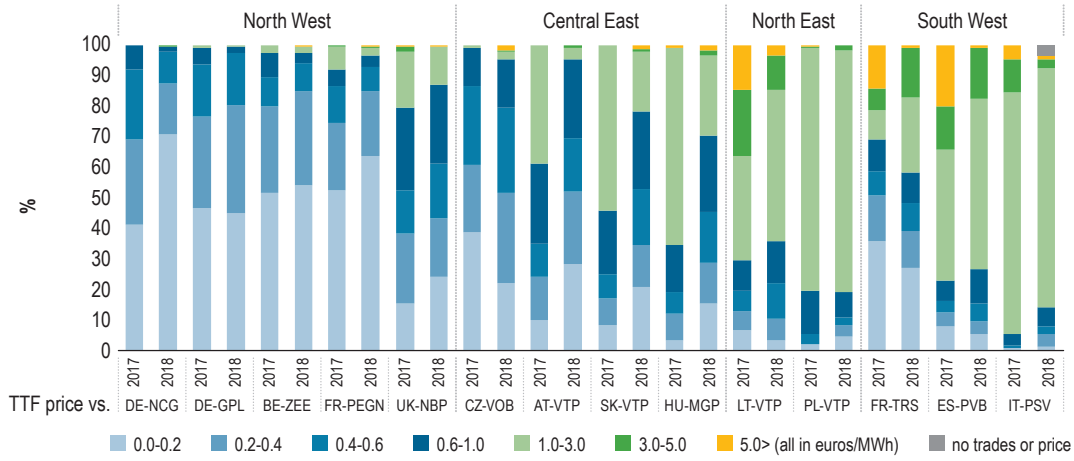
177 High correlation is evident in particular between continental NWE hubs. The main reasons for high correlation between NWE hubs are availability of connecting pipeline capacity, similar market fundamentals, the possibility for upstream suppliers to adjust flows into these markets based on price signals, the structural fostering of hub trading and the relatively lower-priced cost of transportation capacity between the concerned markets. Surpluses of long-term capacity contracts (LTCs) are also a relevant factor as they lower the marginal cost of locational physical arbitrage; however, correlation remained strong in 2018, even as some LTCs expired.

178 Baltic hub prices are the least correlated with those of other EU hubs, which is unsurprising as the Baltic MSs gas markets have, for now, no direct pipeline connection with the rest of the EU's IGM.

179 Among the assessed neighbouring and connected hub pairs, it was the spot prices at the Hungarian and Spanish hubs which were the least correlated to their respective neighbouring hub's prices, although correlation was still relatively high at above 85%. In the case of PVB, the relatively low correlation could be due to the relatively small amounts of cross border capacity available for hub arbitrage and the relatively high price of cross border transportation capacity. In the case of Hungary, it could be due to the inability to export gas to the neighbouring Austrian and Slovak hubs, whose spot prices were more frequently at a premium to the Hungarian MGP than in previous years. However, due to pipeline transportation system limitations, the resulting spread could not be arbitraged away.

180 Overall, price convergence in most parts of the EU remained high in 2018 compared to previous years, as Figure 28 shows. It continued to be the highest between NWE hubs where spot price spreads between TTF and NWE hubs (including AVTP and VOB) were below 1 euro/MWh for 90% of trading days in 2018.

Figure 28: DA price convergence between TTF and selected EU hubs (trading days within given price spread range, %) – 2017 to 2018



Source: ACER calculation based on Platts and ICIS Heren.

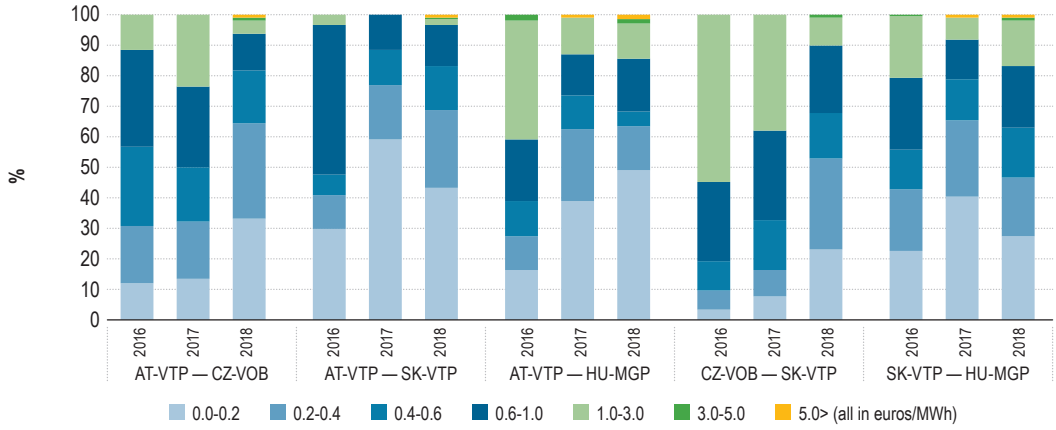
Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

181 In 2018, spot price convergence between the Dutch TTF and other EU hubs improved or remained similar to 2017. Of the assessed hubs, the Mediterranean hubs (PSV, PVB and TRS) and North East European hubs (PLVTP and GET Baltic) continued to have the most frequent high spreads with TTF.

182 Price convergence among markets within a given region is usually higher than between markets in different regions. This is because suppliers active in markets inside a region have portfolios which tend to be similar, which allows for more similar hub quotations. Moreover, regional market fundamentals tend to be similar – e.g. weather-driven demand and impacts of infrastructure outages. The market role that hubs play is usually more akin at regional level, and price arbitrage trading actions are more apparent. For example, in many instances, the same market players keep positions between adjacent hubs (e.g. buying in one and delivering in the other, swapping volumes). All these factors contribute to constructing a closer relationship between prices. To better understand these dynamics, the remainder of this Chapter looks at the convergence of spot market prices between the German hubs and its neighbouring markets; hub price convergence in Central Eastern Europe; and hub price convergence in South West Europe.

183 By virtue of its location, the German gas transmission system plays these days a crucial role in linking NWE European gas hubs with hubs in the South and in particular Central East Europe. In 2018, prices between NCG and neighbouring hubs further converged compared to 2017, the exception being the Czech hub. In the case of GPL, convergence with neighbouring hubs was similar to that in 2017. Spreads between German and neighbouring hubs were lower than 1 euro/MWh for at least 90% of days in 2018, apart from spreads with the Italian PSV (which is only indirectly connected with the German hubs via Switzerland) and the Polish hub. In the case of the latter two hubs, spreads were above 1 euro/MWh on around 80% of the trading days.

Figure 29: CEE hubs spot price convergence (trading days within given price spread range, %) – 2016 to 2018



Source: ACER calculation based on Platts and ICIS Heren.

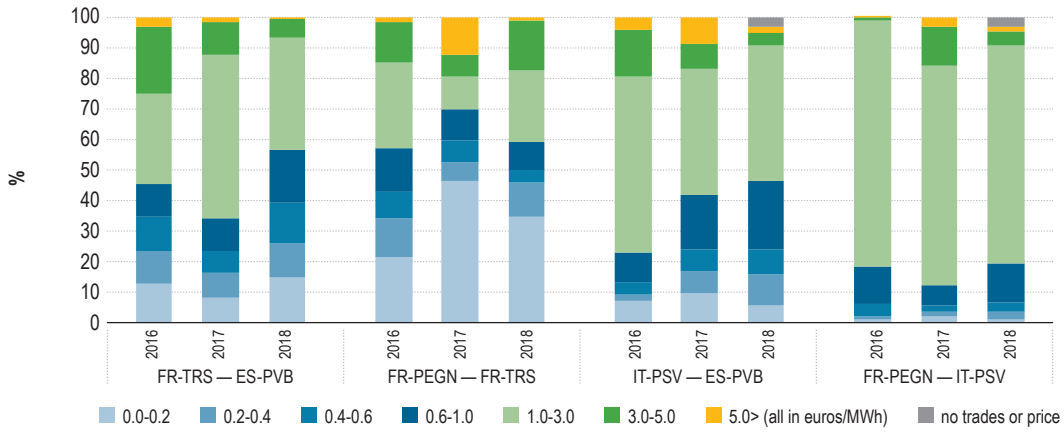
Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

184 As Figure 29 shows, price integration in the CEE region has improved in recent years with spot price spreads lower than 1 euro/MWh on more than 80% of trading days throughout the region in 2018. One of the crucial drivers of price integration are recent infrastructure developments that enabled flows in the West to East direction. This so-called reverse flow firm capacity was instrumental for gas supply competition in the region; shippers active in the region started sourcing from NWE hubs and NWE suppliers entered the market, which put previously dominant suppliers under pressure to offer similar price indexation of LTCs as available in NWE. As the price effects of competition spread in the region, so did hub price convergence.

185 The Austrian hub, which is the most liquid gas market in the region, is a reference point for prices as well as a source of supply for neighbouring markets. However, local supply and demand fundamentals are becoming better reflected in hub prices in the region, for instance in the Hungarian MGP, which is becoming a supply source in its own right, with suppliers active in neighbouring Ukraine, Romania and Croatia likely sourcing some volumes at the Hungarian hub.

186 In 2018, the trend of price integration between CEE hubs continued, with Czech hub prices converging with CEE hubs at the expense of its convergence with NWE hubs. The Slovak – Austrian spot spread remained tight but some high spread days reoccurred, in particular in the late days of February and early March when gas markets in the EU were highly volatile due to unprecedented cold weather.

Figure 30: Mediterranean hubs spot price convergence (trading days within given price spread range, %) – 2016 to 2018



Source: ACER calculation based on Platts and ICIS Heren.

Notes: Spreads in euros/MWh are calculated as the absolute price differential between pairs of hubs, independent of discount or premium.

187 While convergence of Mediterranean hubs, both with NWE hubs and among themselves, is still somewhat lower, it has improved in 2018 as Figure 30 shows. With the merger of the French PEGN and TRS hubs, there is now one price for the entire French system, which could have a positive impact on the Spanish hubs price convergence with the rest of the IGM.

4. Impact of Network Codes on market functioning

MARKET EFFECTS OF IMPLEMENTING NCS

188 Under the Third Energy Package, the Agency is tasked, *inter alia*, with monitoring the state of implementation and the market effects triggered by the implementation of the gas network codes (NCs)[59]. In this Section, the Agency looks at the possible economic effects brought about by the CAM NC, the CMP GLs and the BAL NC and analyses the current transportation tariffs systems in MSs and their likely development after the implementation of the TAR NC. The assessment relies on the transport data available on the ENTSOG Transparency Platform (TP), on the auction reports of the Booking Platforms GSA, PRISMA and RBP and on REMIT data.

189 The key drivers behind the varying performance of gas wholesale markets are supply and demand developments, structural competitiveness and infrastructure aspects. In this context, harmonised and transparent rules for gas transportation networks play an important part, also considering the progressive expiration of the previously long-term gas transportation capacity booked (legacy booked capacity).

190 The Third Package's rules aim to guarantee fair and non-discriminatory network access for all users and transparent market operations; as such, the gas NCs provisions can be considered as promoting competition, ensuring a more level playing field and contributing to improving market functioning. The NCs set a series of rules in order for shippers to access and use gas transportation networks. The enactment of more standardised, transparent and market-driven provisions for capacity booking, congestion management, portfolios balancing and transportation tariffs aims to contribute to the removal of market barriers, hence facilitating competition across European markets, including through the entry of new participants.

191 In the current market context, where vast amount of information and data are available in real time and market fundamentals can evolve rapidly, drawing a clear line between the effects deriving from changes in fundamentals as opposed to those deriving from regulatory reforms is challenging. The analyses presented in this section should be understood in this context.

4.1 Capacity Allocation Mechanisms Network Code effects

192 The implementation of the CAM NC has been mandatory since November 2015, while some MSs have chosen to implement a large number of the NC provisions before this date. The CAM NC establishes a set of rules to harmonise the allocation of transportation capacity across EU MSs via market-based competitive auctions managed through centralised booking platforms. Currently there are three booking platforms, covering different areas: PRISMA (which auctions capacity at the IPs in Western, Southern and Central European MSs[60]), RBP (in the Eastern European MSs[61]), and GSA (on the Polish sides of the IPs and at the interconnection point between Poland and the Czech Republic). The CAM NC sets a uniform calendar for offering capacity via auctions of bundled products of standardised duration by all TSOs in MSs.

193 The first part of this Section gives an overview of the capacity products valid from 2016 to 2018 based on the time when the capacity was booked, while the second part analyses the commercial utilisation of such booked capacity.

194 Figure ii in the executive summary shows the evolution over the 2016–2018 period of the technical capacity and the different CAM capacity products, as well as of the legacy contracts at selected interconnection point sides in Europe[62].

59 Article 9(1) of Regulation (EC) No. 715/2009.

60 Portugal, Spain, France, Germany, Belgium, Luxembourg, the Netherlands, the UK, Ireland, Denmark, the Czech Republic, Austria, Italy, Slovenia.

61 Slovakia, Hungary, Croatia, Romania, Bulgaria, Greece.

62 Includes 212 interconnection point sides located in the 21 MSs with transportation networks in place, where capacity is auctioned via centralised booking platform as per CAM Network Code and for which reliable data are available on ENTSOG TP. Interconnection point sides of Estonia, Finland, Latvia, Lithuania and Sweden are not included because those MSs do not allocated capacity with CAM auctions, while Cyprus and Malta do not have a gas transportation network.

195 One of the most noticeable effects of the CAM NC implementation in almost all MSs is that it enables shippers better to profile capacity bookings based on seasonality, as it allows to adapt capacity bookings for the winter months compared to the capacity booked for the summer months. This effect was one of the aims of the CAM NC, and it promotes the efficient utilisation of the network and of the wholesale gas markets.

196 In 2017, the CAM auction calendar was amended. 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. In addition, the single quarterly capacity session (previously held in June every year for all the quarters of the following gas year) was divided into four sessions during the year. The impact of the aforementioned amendments is mainly visible in the increase of the bookings of quarterly capacity for 2018, as the new mechanism offers more flexibility to network users and increases the usefulness of the quarterly product.

197 The share of long-term legacy contracts is decreasing: capacity booked before the end of 2015 amounted to 93% of the 2016 capacity, decreasing to 81% by the end of December 2018, as shown in Figure ii. The IP sides analysed are the CAM relevant ones, which are mainly those located between MSs rather than those connecting a MS with a Third Country. This decrease is mainly due to the expiration, in October 2018, of the legacy capacity at the interconnectors linking Great Britain to Belgium (IUK) and to the Netherlands (BBL). Further volumes of long-term transportation legacy contracts at EU IP sides will expire gradually until 2025 after which a quicker expiration will occur until 2035. By that date almost all historical contracts will have expired.

198 In October 2018, 90% of the legacy capacity booked at IUK expired. This capacity was not replaced by any significant bookings for the last three months of 2018. The capacity that had been progressively expiring, since 2016, at the BBL interconnector was also not replaced by any sizeable new bookings[63]. This situation is not common among the IP sides in most other MSs. In most MSs where capacity expired, it has been (in some cases even more than) replaced by new bookings, as explained in paragraph (202) below.

199 The situation observed at the British interconnectors – where the expired legacy booked capacity has not been replaced – could be related to the specific characteristics of those IP sides. The yearly utilisation of capacity at both IUK and BBL was historically around 20%, as the two interconnectors have always been used as optimisation tools between two advanced and well-diversified markets rather than as primary sources for supply gas to the MSs that they connect. In addition, the result of the referendum held on June 2016 on 'Brexit' in the UK contributed its part as it brought uncertainty over the development of the UK gas wholesale market.

200 Despite the relatively marginal role of the British interconnectors in the overall supply of gas to the EU MSs, their legacy booked capacity's expiration, together with the caps established on the production at the Groningen production field might have produced some effects on the other IP sides in NWE starting from the last quarter of 2018. More yearly capacity was booked from Germany and Norway into the Netherlands for the gas year 2018/19, which led to more nominations during the last quarter of the year at those IP sides and to fewer nominations from Belgium into the Netherlands during the same period. Section 4.5 elaborates on the further market reasons for the non-replacement of capacity at BBL and IUK, considering the relationship between spreads and tariffs and the marginal role of those interconnectors and provides with a forecast on the future levels of booking at these interconnectors and at the other EU IPs.

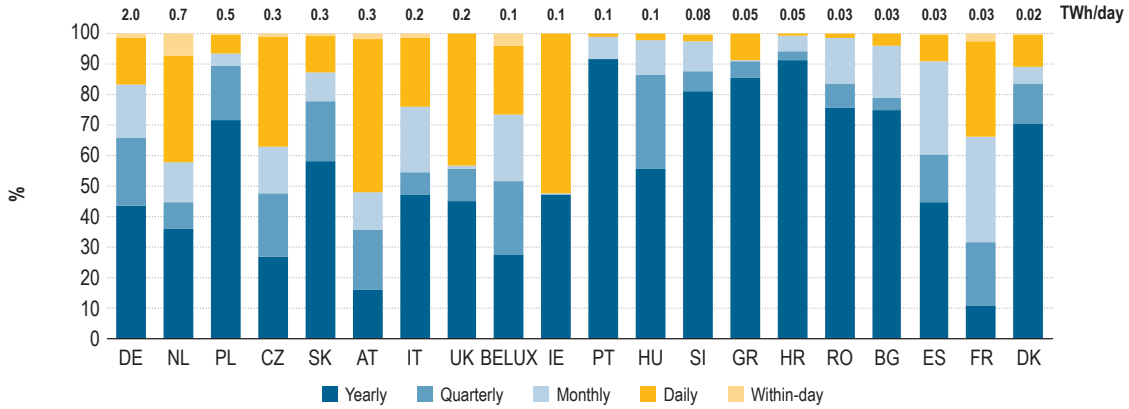
201 In Belgium, France, Germany, Hungary, Italy[64], Poland, Portugal and Spain, the expired legacy capacity at the corresponding IPs sides was almost always replaced by new bookings. In Austria and Bulgaria very low volumes of capacity expired, but still new capacity was booked. In other MSs (the Czech Republic, Croatia, Denmark, Greece, Ireland, the Netherlands, Slovakia, Slovenia and Romania) the expired capacity was not replaced completely by new bookings. In the Netherlands, the spot capacity (day-ahead and within-day) was booked more than in any other MS: within-day capacity was booked even more than in the United Kingdom despite different balancing designs in those two MSs (the balancing system in the UK is known to promote within-day trades, see Section 6.3.1.).

63 At IUK, the total new bookings for 2018 after the long-term capacity expiration totalled for a volume equal to 0.6% of the expired capacity and this was year-ahead capacity booked for the gas year 2018/19. In addition, some quarterly capacity was booked for 2019. At BBL, in 2018, 6% of the expired capacity was booked as daily products and 12% of the expired capacity was booked as monthly products.

64 In Italy only Tarvisio, connecting Austria with Italy, is a CAM-relevant point.

202 As for the type of capacity products booked via the CAM auctions, shorter-term commitments dominated capacity bookings for the 2016–2018 period: 70% of the CAM capacity booked for the period was short-term capacity (quarterly, monthly, daily, within-day products), 29% was year-ahead capacity and only 1% was longer than one year-ahead.

Figure 31: Member States' volumes of CAM capacity products booked for the period 2016–2018 and their breakdown by product – daily average (TWh/d) and %



Source: ACER calculation based on GSA, PRISMA, RBP.

203 As can be derived from Figure 31, the IP sides in Germany alone account for 40% of total European bookings of CAM capacity, with an average of 2 TWh/day. In fact, the top three EU MSs – Germany, the Netherlands and Poland – covered almost 65% of the total EU CAM booked capacity and the top six MSs account for more than 80%. The results reflect various elements, such as the bigger size of the within-EU IP sides located in those MSs (given also their geographical position)[65], the higher levels of gas consumption or alternatively high volumes of transits in those MSs and the higher volumes of expired LTCs that have been replaced.

204 In MSs with bigger volumes of CAM bookings, capacity was mainly booked shorter-term, while in most MSs with minimal bookings of CAM capacity (where the capacity booked was less than 0.1 TWh/day) the share of CAM yearly products was higher. This might also reflect the better functioning of the former hubs, as shorter-term capacity products allow shippers to adapt more to variations in shorter-term market conditions and to hedge volumes, and those behaviours are more frequently observed in transparent and liquid hubs.

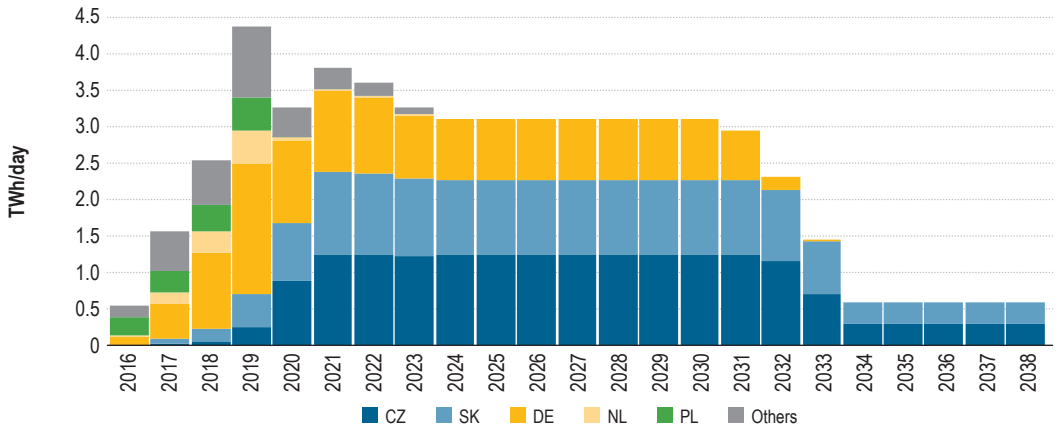
205 Multipliers, which apply to the different types of short-term capacity products, also play an important role in the shippers' choice on the type of capacity product to book. Lower short-term multipliers incentivise the booking of short-term products over the booking of yearly capacity. Section 4.5 analyses how different transportation tariff's multipliers affect the gas wholesale markets and their forecasted effects after the implementation of the TAR NC.

206 Currently, the shippers' preference is to book capacity on a shorter-term basis for up to one gas year-ahead. This is driven by the strategy to pursue as much flexibility as possible, also in the choice to ship gas via pipelines or via LNG. Shippers aim to avoid being locked-in when booking capacity, especially given the current situation of historical capacity overbookings, uncertainty over the forward conditions of the European gas markets, progressive expiration of long-term transportation contracts and renegotiation of the take-or-pay gas commodity contracts with the softening or cancelling of the long-term take-or-pay clauses. They pursue the minimisation of the exposure over the uncertainty of forecasted transportation tariffs (i.e. TSO's under-recovery) and the better portfolio profiling by booking capacity mainly on a shorter-term basis, even if the multi-yearly capacity is less expensive than the shorter-term capacity.

207 The CAM NC establishes that yearly capacity must be offered for at least the subsequent five gas years and up to the next 15 gas years. The volume of bookings of long-term capacity valid from 2016 to 2038 and made in the period 2016-2018 is shown in Figure 32.

65 As explained in footnote 62, the majority of IP sides analysed are within MSs IP sides, according to the CAM NC's definition of "CAM relevant" IP sides.

Figure 32: Member States' volumes of multi annual CAM capacity booked for the period 2016–2038 in EU MSs (daily average, TWh/d)



Source: ACER calculation based on GSA, PRISMA, RBP.

Note: Volume of incremental capacity could be included in the allocated auctioned volumes. "Other" includes the other 14 MSs where CAM NC is implemented.

208 For the 2020–2032 period, most multi-annual CAM capacity was booked in three MSs only: the Czech Republic, Slovakia and Germany, in particular along the route from Germany (Nord Stream) to the Czech Republic and then to Slovakia (both directions). The capacity booked in those three MSs is the only capacity booked for the years from 2024 to 2032, then from 2032 to 2038 capacity was only booked in the Czech Republic and Slovakia. While these data show that the multi-annual capacity offered is booked in some cases, it also shows that these bookings so far are only made for rather specific purposes. The fact that these capacities were booked at the reserve prices shows that there was very limited competition in the auctions.

4.2 Concentration of bookings

209 The concentration of the bookings of yearly capacity – shown in Figure 32 above – at the IPs from the entry point of Nord Stream into Germany to Slovakia via the Czech Republic (both directions) was particularly high. In any case the regulatory and the competition frameworks should safeguard sound competition in case a single entity, or just a few entities, book the entire capacity offered at one IP side, even if there is currently no demand to book such capacity from other shippers, mainly midstreamers.

210 In 2017, the Hungarian NRA established that only the capacity valid until 2019 could be offered in the yearly auction of 2017 due to concerns about market foreclosure, as one market player had booked all the capacity following the route of Nord Stream 2. In 2018 and 2019 a more coordinated approach was taken between the NRAs of Hungary, Austria and Slovakia. Following a market consultation, it was decided, in due time, to offer multi-yearly capacity products at the IPs between Hungary and Austria and between Hungary and Slovakia only up to the next 5 gas years and to increase the share of short-term capacity to be auctioned from the CAM NC's 10% threshold to 50% for the last three years of the period.

211 Highly booked IPs provide stability for infrastructure investment recovery for TSOs. The ideal IGM situation is that high booking at the distinct IPs that grant access to the market are the result of sound competition between multiple market participants, instead of sole control by a (few) incumbent(s). The latter is not necessarily bad per se, but restricting the access to alternative suppliers can put upward pressure on prices. The IGM requires third-party access, and CAM and CMP NCs provide detailed rules to guarantee fair access.

212 Therefore, assessing the concentration of IP capacity bookings is important to understand the degree of competition for such capacities. By means of processing REMIT data[66], which contains information about the market participants holding IP capacity, an assessment of the concentration levels of capacity holdings was undertaken, which has resulted in the following four observations.

213 First, when comparing the concentration levels of the various capacity products offered at the booking platforms, the short-term capacity products (e.g. day-ahead) tend to have the lowest concentration levels. This is to be expected, as shorter-term products attract additional market participants in pursuit of prompt supply portfolio optimisation. However, the number of market participants booking longer-term products is significantly lower.

214 Second, when comparing the concentration levels of the longest-term capacity products, i.e. year-ahead auctioned under CAM, with capacity booked from historical contracts, the latter is typically higher. As such, it could be inferred that capacity allocation via auctions – considered as more transparent and market-oriented – nurtures competition. This also reflects the changed environment of liberalised markets.

215 Third, there is, however, evidence of highly concentrated IPs even where capacity is booked via competitive auctioning. The CR3 values for newly auctioned year-ahead products for several key gas supply routes are above 60%[67]. This could indicate that the picture for long-term capacity bookings has not dramatically changed since the introduction of the capacity auction mechanisms. This is partly because, in many cases, the same companies currently holding current capacity rights are the ones prone to acquire new capacities into the future, for safeguarding their existing supply commitments[68]. The picture is anyhow diverse. There are also examples of relatively lower concentration levels for long-run supplies. Selected CEE reverse flow supply corridors would be examples of that.

216 Fourth, upstream suppliers are more and more active in booking longer-term capacity products. This trend is likely to continue in the coming years, as more LTCs are expiring. As discussed in Section 4.5, a situation where tariffs recurrently exceed hub spreads could be a limiting factor for capacity acquisition by EU midstreamers in the years to come. Gas producers, meanwhile, are expected to take a more active role in capacity bookings.

217 In this regard, this Section analyses the effects that gradual expiration of LTCs may produce on the concentration of bookings at the IP sides. On the one hand, based on REMIT data, IP sides' capacities in use[69] by the main non-EU upstream producers do not reveal a striking growth over the last three years (although results can moderately vary per IP side).

218 On the other hand, when looking at the capacities booked for future gas delivery (i.e. year-ahead capacities auctioned up to 2018 plus prevailing long-term contracts up to the year 2035), the total share of upstream suppliers' booking rights is much higher; more than twice the capacities in use for the period 2016–2018[70]. It is true that it is not currently in the interest of some EU midstreamers to book capacity for the very long-term, as they might want to wait to profile their booking needs closer to final delivery as to limit financial exposure. Forward bookings to date show, however, that the share of IP capacities controlled by non-EU producers will be larger in the years to come.

219 Overall, a valid reflection is whether the CAM NC[71] and the CMP GLs in their current form will be sufficiently effective in addressing potential market foreclosure risks that could arise if one or a few companies control capacity over extended periods, potentially hampering new entrants.

66 Data reported about transportation contracts, covering both auctioned capacities and bilateral contracts still in place. Firm, interruptible and conditional capacities included. Bundled and exit-side unbundled capacities processed. Secondary capacity transfers also taken into consideration.

67 CR3 denotes the sum of market share of the three largest firms. CR3 values between 40% and 70% reveal medium concentration levels, whereas values above 70% are indicative of high concentration.

68 The case could also be that a company substitution has occurred – i.e. a midstreamer has been substituted by an upstreamer, changing the contractual terms of their supply contracts – but not a replacement of one by several new companies.

69 The analysis looks at the sum of all the capacities rights in service along the year, with independence of the duration of the procured capacity product. i.e. a year-ahead product for gas delivery along the whole year 2018 accounts for 365 times more capacity than a day-ahead product of similar size, both products expressed in identical purchasing units, kWh/h.

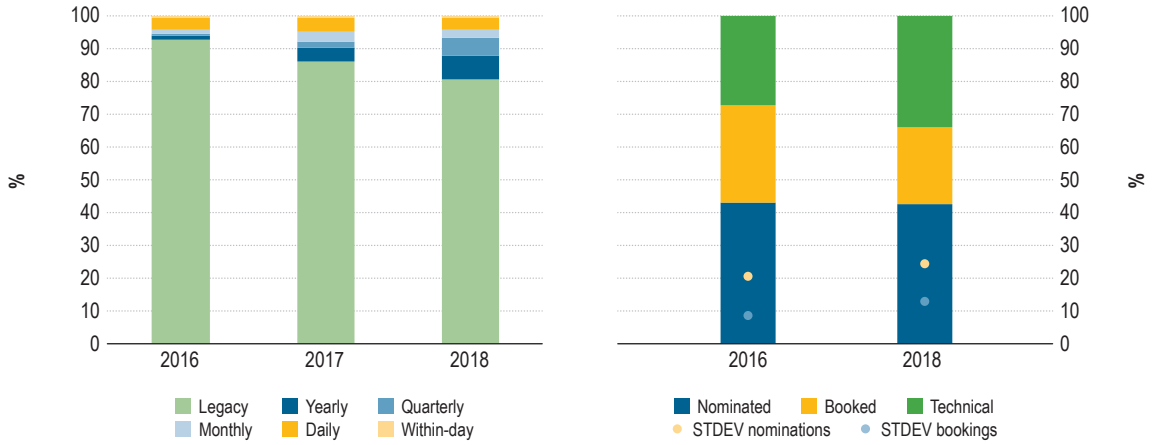
70 The forward delivery bookings also include incremental projects, where the presence of upstream suppliers would be higher in order to secure investments revenue recovery.

71 The code reserves 10% of capacity for one year-ahead products and another 10% for quarterly and shorter products.

4.3 Integrated effects of Network Codes

220 Figure 33 shows both the booked capacity breakdown by type of capacity product (a) and the share of utilisation of such booked capacity over the 2016–2018 period (b). The decrease in the total booked capacity - Figure 33 (a) - lead to its better commercial utilisation by the shippers over the years Figure 33 (b). However, the levels of capacity booked and of its commercial utilisation (nominations of booked capacity) varies greatly across the EU IP sides and directions.

Figure 33: a) Breakdown of capacity booked for the years 2016 and 2018 (%) and b) ratios of capacity booked, nominations and standard deviation of bookings and nominations for the years 2016 and 2018 (%)



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

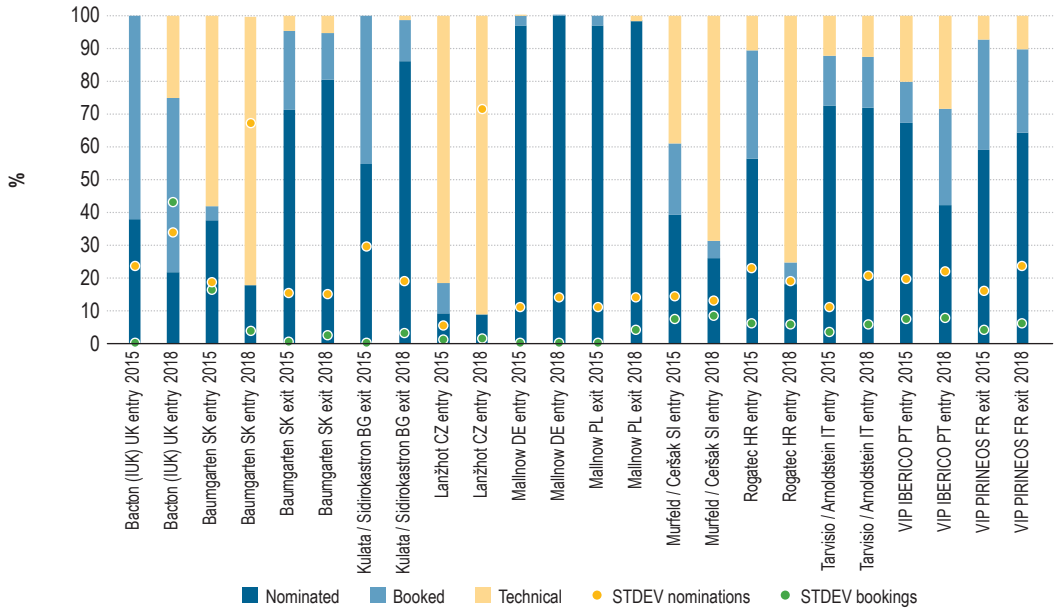
221 At EU level, as observed in the previous years, an increased situation of overcapacity of the gas networks can be observed[72]. 72% of the available firm technical capacity was booked in 2016 and this share decreased to 66% in 2018. The ratio of IP nominations over the technical capacity also slightly decreased over the period. However, selected IP sides show a much higher use. In fact, on many occasions, the highest utilisations are registered at key supply corridors.

222 There are, however, differences: the most booked and commercially used IP sides are also the ones with the biggest capacity in the European gas network. On the other hand, the IP sides going in the opposite direction of the dominant flow of the bidirectional IPs, or the IPs where virtual reverse capacity is offered, are much less booked and used by shippers and are usually the ones with smaller capacity.

223 Standard deviations of nominations and bookings – which serve to evaluate the distribution of their daily levels – increased over the last three years. This is a sign that IPs' capacities are increasingly booked and commercially used in order to accommodate variable demand needs and price signals.

72 The usage of averages is illustrative in order to show the overall European situation. Peak utilisation ratios of infrastructure are also needed when dimensioning the gas system.

Figure 34: Booking and utilisation ratios of transportation capacity at selected CAM relevant points – 2015–2018 (%)



Source: ACER calculation based on ENTSOG TP.

224 As Figure 34 shows, at some IP sides the total booked capacity over the 2015-2018 period increased, for example in the main direction of the Baumgarten, Kulata, Mallnow and VIP Pirineos IPs. Those are the most used IPs in Europe. At most other IP sides, it was the opposite: less capacity was booked in 2018 and, in some cases, even less was nominated on average in 2018 compared to 2016. The two categories of IP sides share the increase in the standard deviation of both the booked capacity and the nominated capacity.

225 This confirms that, as presented above, shippers respond more and more to shorter-term price signals with the bookings of shorter-term capacity and better utilisation of the capacity booked.

226 Further progresses, however, should be made in the harmonisation of capacity products and in the harmonisation of transportation services. The Agency's study on conditionalities in capacity products[73] shows that, in some MSs, the share of conditional capacity products is still relevant, for example in Germany, where it amounts to 50% of the all capacity products. This raises the question of whether the entry/exit system established by the Third Energy Package should be reviewed in order to include these exceptions or if exceptions should be removed in order to pursue a full harmonisation of systems, as established by the Third Package.

4.4 Overview of cross-border transportation tariffs: price levels and Tariff Network Code effects

227 This Section aims to analyse specific effects of the TAR NC. In doing so, it compares the current levels of cross-border tariffs at European IPs and traces their projected evolution, following the implementation of the TAR NC[74].

228 As a rule, transportation tariffs are added to the commodity procurement costs to establish the gas supply prices[75]. As such, the level of cross-border tariffs can promote or hinder the supply of gas from certain origins.

73 The Agency's Report on the conditionalities stipulated in contracts for standard capacity products for firm capacity and the underlying consultancy's study and data are published at the following link: https://www.acer.europa.eu/Media/News/Pages/ACER-reports-on-gas-conditional-capacity-products-in-the-EU.aspx.

74 The new RPMs, in accordance with TAR NC principles, shall enter into force for the first new tariff-period after May 2019. The transparency provisions entered into force in October 2017.

75 In the gas industry, the concept of netback pricing is common. It refers to the net revenue obtained by the gas producer after subtracting from the gas sales price the production costs and the transportation charges. However, transportation tariffs may not be fully reflected in the final supply prices under certain conditions (see Section 4.5).

229 Above all, transportation costs of *marginal gas supply* sources are key, because they tend to discipline price formation in wholesale markets[76]. Tariff increases for those IPs that accommodate *marginal supplies* may lead to welfare transfers from gas customers to *non-marginal* suppliers'[77].

230 Hence, non-discriminatory and cost-reflective tariffs are core to a fair IGM. The gas networks' tariffs in MSs should be set in accordance with reference price methodologies (RPMs). In this respect, the TAR NC has established standards for more homogenous and transparent RPMs. The Agency reviews the proposed methodologies, examining if they do not distort cross-border gas trade and competition, while at the same time avoid cross-subsidisation between network users and are set with sufficient transparency.

231 The TAR NC establishes that the same RPM should be applied to all network points in an entry-exit zone, considering specific cost drivers. However, the code also allows for some discretion in the implementation of RPMs if the aim is to pursue a better operation of the gas network. In this case, adjustments are allowed, for example, to stimulate competition[78]. 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[79].

232 However, as adjustments may lead to discrimination issues, NRAs should exercise caution in applying them. Any such adjustment must be motivated in the NRA's RPM decisions, which shall include assessments about the impacts of the proposed RPM. Overall, RPM proposals ought to include the European perspective and to foster MSs' supply price integration. So far, the proposals assessed by the Agency related to adjustments do not show that there are important discrimination issues.

233 The Agency has so far reviewed the RPM proposals received from NRAs but not all NRAs have submitted them in due time[80]. Figure 35 compares the reviewed RPM proposals with the methodologies currently in force. Most NRAs have opted for postage-stamp methodologies, with the justification that these provide a good trade-off between simplicity and efficient competition and are more suitable for meshed networks, where there are usually no dominant flow directions. The documents reviewed by the Agency are consultation documents, meaning that the final RPM as decided by the NRA after the consultation and the Agency's report may deviate from the one presented in the consultation document.

76 The marginal supply source can vary across the year in accordance to evolving market conditions. The disciplining effects on prices are more visible in more competitive markets.

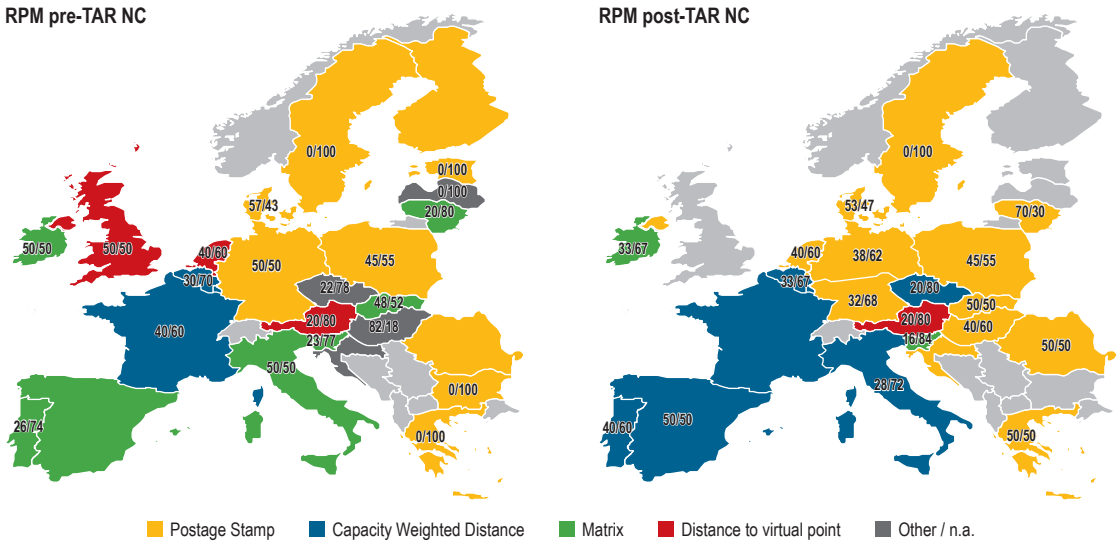
77 As discussed in the CEER Regulatory challenges paper, this transfer effect is exacerbated when gas sets the *marginal price* in the power market.

78 There can be a conflict between the *cost reflectivity* and the *efficient competition* principles from the TAR NC. Purely cost reflective RPMs can result in tariff differentials between IPs which could discourage imports over certain routes. Therefore, trade-offs between the two principles might have to be made.

79 Discounts are also allowed – and even prescribed - for points of a specific nature, such as those points connecting to UGSs or LNG facilities.

80 The deadline for RPMs submission was the end of May of 2019. See the Agency analysis on the national tariff consultation documents here: https://www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx.

Figure 35: Evolution of tariff methodologies and entry/exit splits in EU MSs before and after TAR NC implementation – 2018 – post 2019



Source: ACER calculation based on NRAs RPMs (2019).

Notes: More complex RPMs, i.e. matrix, distance to virtual point aim for greater cost reflectivity. Postage stamp methodologies are simpler. For the Polish segment of the Yamal pipeline a CWD methodology is proposed with a 52/48 E/E split. BBL and IUK set their tariffs based on a number of factors but do not apply proper RPM based on costs.

234 Another relevant element is the choice of the entry-exit split, which can considerably affect transportation costs levels[81]. The split must make use of specific cost drivers, aiming to safeguard the cost-reflectivity principle. However, some adjustments may be legitimate. Figure 35 shows the entry-exit splits currently used and those proposed.

235 NRAs have proposed a diversity of RPMs so far, with a mixture of cost drivers, parameters[82] and adjustments, which aim to adapt the specific characteristics of national systems to the TAR NC. Some cases in point are listed in the paragraphs below. The views of the Agency for each of the points are also outlined[83].

- **Entry-exit splits:** 50/50 is the most common practice and is seen as the theoretical benchmark in the NC. In Austria and Slovenia, the entry-exit split has been set at around 20/80. In the Czech Republic a 20/80 split is also set in order to minimise tariff discontinuities (i.e. it mirrors the current one). In Italy, a 28/72 value is proposed to favour the alignment of PSV prices with NWE hubs. Overall, lower entry tariffs seek to incentivise market entry and a lower hub price, whereas higher exit tariffs increase transportation costs for consumers and exporters. However, any deviation from the cost-reflectivity principles shall be duly justified, as it may entail a risk of cross-subsidisation and/or impact cross-border trade and market integration.

- **Opposite IP directions:** In close relation to the preceding paragraph, the combined effects of RPMs, entry-exit splits and cost-drivers can lead to sizeable differences in the gas transportation costs across a MS in the dominant or in the lesser used flow direction (i.e. the sum of the entry and the exit fees collected at a given border 1 to border 2 route within the MS can vary depending on the direction of the flow).

81 In most MSs, the entry-exit split is an ex-ante assessment, but can also be determined ex-post as an output of the cost allocation methodology. All other factors being equal, the decision to move from a 25/75 entry-exit split to a 50/50 split would double reference prices at all entry points.

82 Several other factors affect the tariffs' values, for example the capacity-commodity split, which determines the percentage of revenues to be recovered from a capacity charge (i.e. right of utilisation) or an actual flown volume charge. The code establishes that most revenues shall be recovered by the capacity tariffs.

83 The list aims to illustrate some representative adjustments. ACER's positioning at each of them has been expressed in the pertinent RPMs consultation analysis.

Lower tariffs in the dominant flow direction are usually the result of higher booking levels, whereas lower tariffs in the non-dominant direction may be applied to attract flows[84] or they may be justified by considering non-dominant flows less accountable for the route investment costs, or in fact facilitating better use of the capacity in the dominant flow direction due to the possibility of netting the flows. As an illustration, in Portugal the RPM results in zero tariffs at the VIP Iberico exit side. This is justified by the Portuguese NRA by the historically dominant use of the interconnection to import gas from Spain, which is deemed accountable for the totality of the investment costs. On the other hand, in the Czech Republic, gas flows in the western dominant direction – i.e. the tariffs for moving gas across the Czech Republic from Lanzhot (SK) to Waidhaus (DE) is almost half of the tariffs applicable to gas flowing in the reverse and less-used eastern direction. Similarly, transporting gas across Belgium from Germany to the IUK is costlier than from the IUK to Germany.

These results are deemed valid when resulting from homogeneous cost-reflectivity considerations, consistently applied entry-exit splits and akin cost drivers (e.g. technical capacities may differ between the two flow directions). However, they may raise some issues of cross-subsidisation when not duly justified. Particularly, the setting of zero tariffs at a given IP side is in general not supported by the Agency, as it entails not applying the same RPM to all points of the network.

- **Specific points' discounts:** In Belgium, Denmark, the Czech Republic, Germany, Hungary, Italy, the Netherlands, Poland, Romania, and Sweden discounts ranging from 50% to 100% are offered at UGS entries and exits. A minimum discount is prescribed to avoid double charging for transmission to and from UGSs, which may also favour their use. In Croatia, Greece, Lithuania and Poland discounts are also granted to the entry points from LNG facilities into the network. For example, in Poland, the discount applied at the LNG terminal is planned to reach 100% and no commodity charges will be levied. In Greece, the entire bundled access from the LNG terminal into the network is made equal to the pipeline entry tariffs. To compensate the related missing revenues, NRAs propose different scaling factors at other network points.

  In Germany, the RPM includes tariff discounts of up to 10% for conditional products, widely used by German TSOs. A biogas broad charge is announced to cover for its injection costs, whereas tariffs for the entry points to the network from biogas installations and power-to-gas are set to zero.

  Overall, there are two types of justifications for applying these discounts. First, the offered service has a lower market value than the firm product (e.g. this is the case for the conditional or interruptible capacities' discounts). Second, the service is deemed to induce positive externalities to the whole system (e.g. UGSs, LNG terminal facilities). In the latter case, the needed rescaling to compensate the missing revenues should be applied to the beneficiaries of these externalities. Overall, discounts are an accepted practice as far as the under-recovery resulting from their application is managed within the same tariff period. In the view of the Agency, inter-temporal cross-subsidies shall be minimised with the objective of recovering transmission revenue in a timely manner.

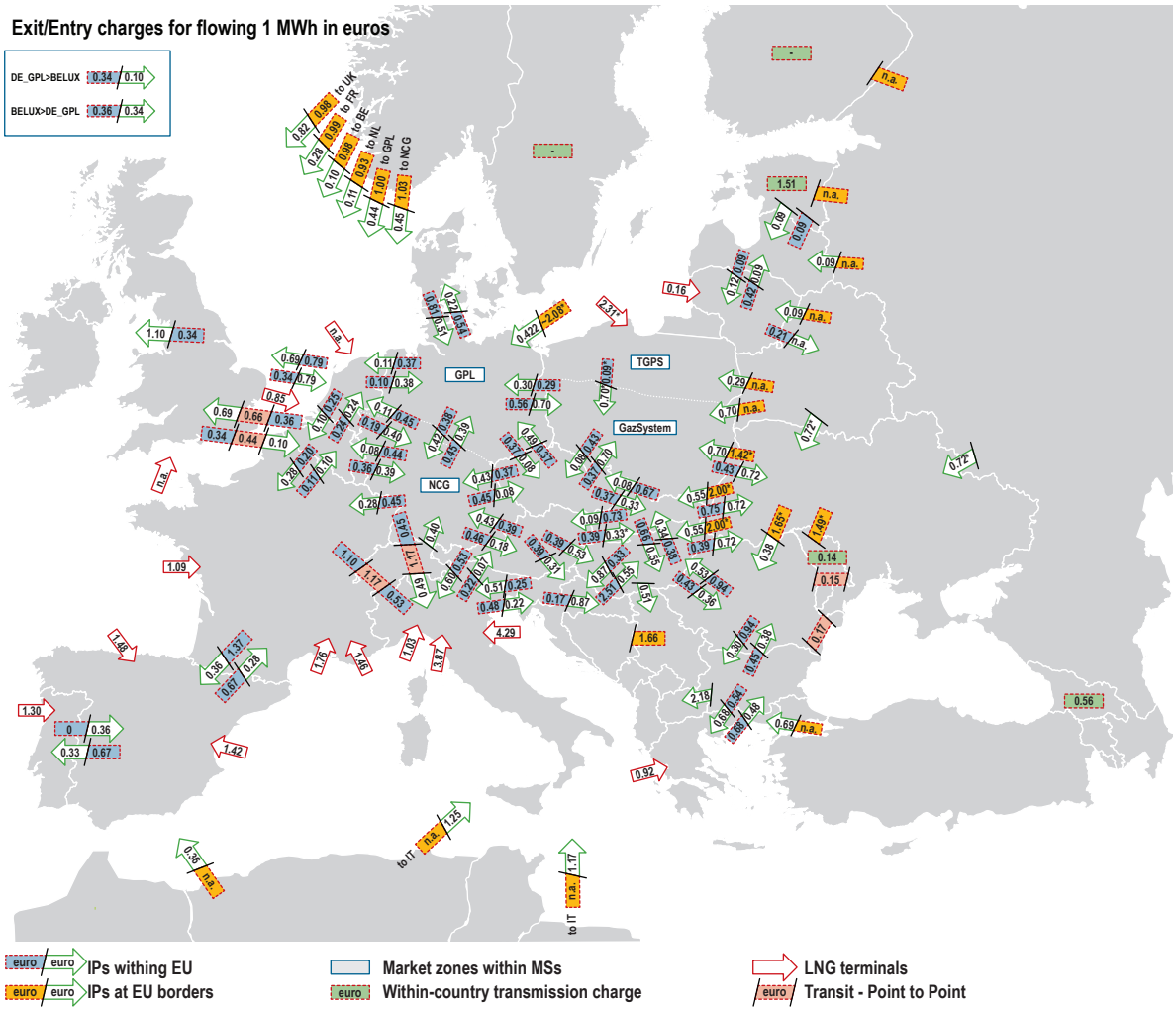
- **Adjusted RPMs:** In Slovakia, a postage stamp RPM has been initially proposed, but has not been applied to all points of the network; instead, most IPs tariffs result from benchmarking. In Belgium, a CWD methodology is proposed, but all entry IP tariffs and all domestic exits are equalised for simplicity.

  Benchmarking and equalisation adjustments are included in the TAR NC in order to pursue a better operation of the gas systems. However, they must be duly justified, including an assessment of their effects elsewhere in the network. Arguably, the justification of benchmarking is more complex, as it entails substantiating why another route is in competition.

236 Additionally, the TAR NC states that for transparency reasons, all IP charges must be published on ENTSOG's TP. A simulation of all the costs incurred when flowing one GWh/day/year of gas must be made available. This is something which has been covered in the MMRs over the last six years. Figure 36 shows the assessment for 2019, which also includes the system access costs of LNG and those of the EnC CPs.

84 This is also because, in some cases, reverse capacity is offered as interruptible - and as such, at a discount - under the justification that in the absence of dominant flows they may not be possible.

Figure 36: Comparison of average gas cross-border transportation tariffs and LNG system access costs – 2019 – euros/MWh



Source: ACER calculation based on ENTSOG, CEER and individual TSOs (2019).

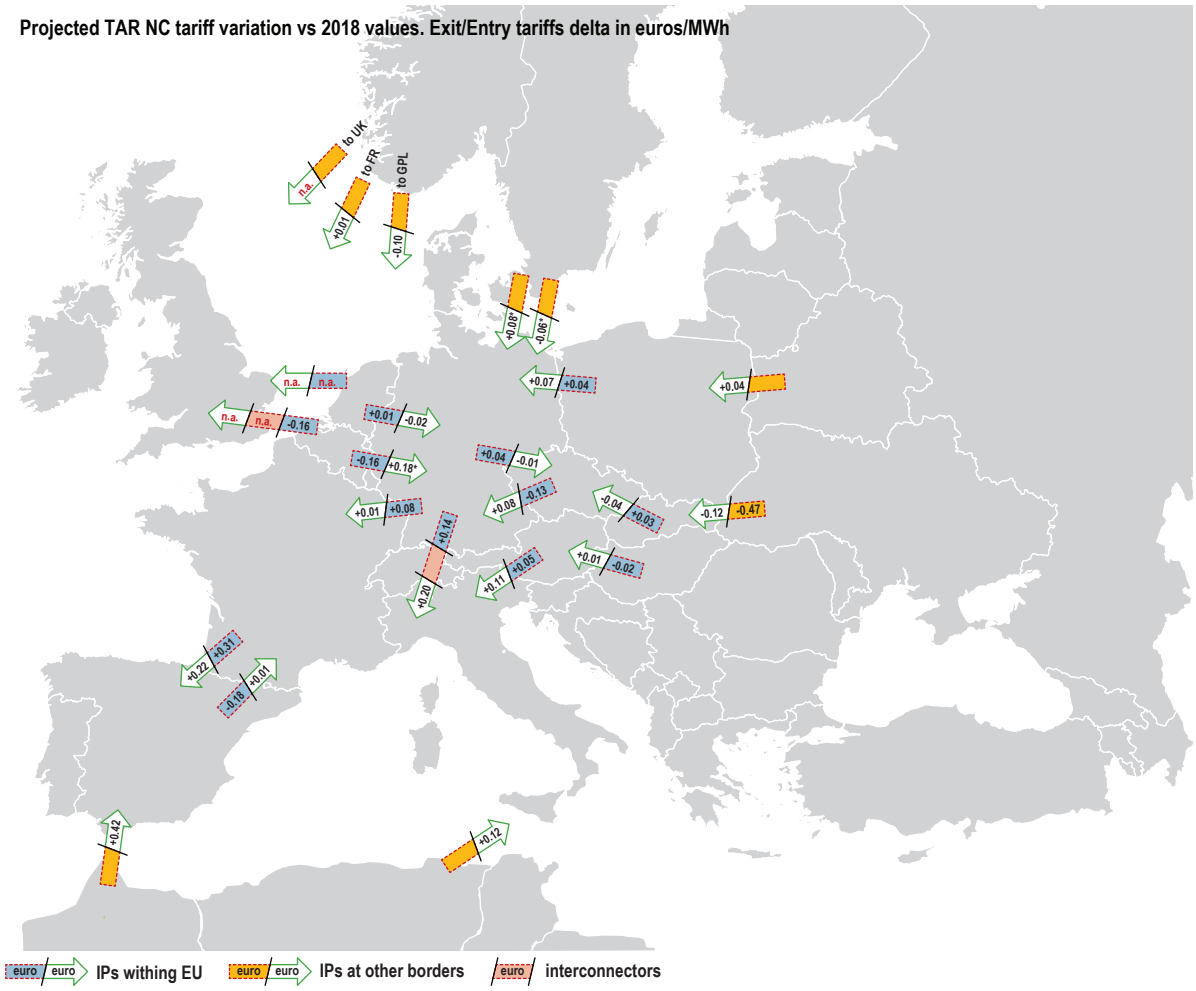
Notes: For cross-border IPs, the map displays 2019 exit/entry charges in euros/MWh for the yearly product. See MMR 2016 annex 1 for further clarifications. For LNG terminals, the figure considers the costs derived from the bundled service (unloading + storage + regasification) of a 1,000 GWh LNG cargo, which regasifies the whole amount in a period of 15 days, plus the entry tariffs from the LNG terminal into the transportation network[85]. At the Slovak IPs only a range of tariffs can be provided since the final price is a function of the booked capacity volumes. Nord Stream tariff is an educated guess on the basis of market intelligence reports assessments. Within Poland, besides physical flow between the Yamal Pipeline (TGPS) and the Polish VTP (Gaz-System) a backhaul reverse flow is possible.

237 Figure 36 shows the current transportation charges across distinct borders and routes[86]. It also helps to infer how tariffs could affect sourcing costs. Complementarily, Figure 37 shows how tariffs could look like post 2019, reflecting proposed RPMs. Tariff levels would be also affected by the amount of allowed revenues within the new regulatory period.

85 Entry tariffs from LNG terminals into transportation networks are included within the arrows' figure; for example, for France they amount to 0.27 euros/MWh and for Spain 0.36 euros/MWh. All UK LNG terminals, the Dutch Gate terminal and the French Dunkerque terminal are not included in the map.

86 Comparisons are subject to a number of caveats: cost-minimising routes would be built on nominal yearly tariffs. However, prevailing long-term commitments and maximum flow limitations could restrict the scope of new capacity bookings. In addition, profiling capacity products across the year may affect booking decisions; this last element is also influenced by the distinct tariff multipliers' and the capacity-commodity tariff split.

Figure 37: Comparison of average gas cross-border transportation tariffs before and after the TAR NC implementation for selected gas supply routes – tariff delta in euros/MWh



Source: ACER calculation based on ENTSOG, NRAs and individual TSOs (2019).

Notes. Yearly capacity products considered. At those borders with more than one IP or TSO, tariff variations are assessed on a capacity weighted average; distinct IPs may see different deltas. BELUX into DE assessment refers solely to the TENP pipeline. Tariff deltas in the Greifswald IP (i.e. the German landing point of Nord Stream) differ per route: OPAL sees tariff rises (+ 0.06 euros/MWh approx.) while NEL tariff drops (- 0.08 euros/MWh approx. depending on the TSO). Within German-zones tariff deltas vary per TSO. Overall, on a weighted average, GPL entries decrease by 0.10 euros/MWh while NCG entries rise by 0.08 euros/MWh approx. Exit tariffs see more limited variations.

238 Figure 36 reveals that access cost of external-EU gas[87] has been so far the lowest for Norwegian supplies into NWE MSs[88]. In addition, the access cost through Nord Stream into Germany had been more competitive than across the Ukrainian-Slovakian gas supply route[89]. However, this situation is likely to change after the Ukrainian tariff methodology revision, which should sizeable reduce entry, exit and storage tariffs from 2019 onwards to increase transit volumes to the EU and enhance the attractiveness of Ukraine's storage capabilities[90].

87 I.e. shipping charges across the non-EU producer country plus, possibly, other non-EU countries transit networks until the EU borders plus the entry-side fees charged at EU entry points.

88 Norwegian off-shore transportation costs are price competitive and show limited variation. However, entry fees applied at distinct MSs can differ significantly.

89 Exit tariffs from Ukraine into MSs shown in Figure 36 could not be applied in practice. Lower transportation tariffs are in place, linked to the prevailing gas transit contracts signed with Gazprom.

90 Moreover, Slovakia has proposed in its new RPM to lower the entry tariffs from the Ukrainian border.

239 LNG access costs continue to be the highest. Figure 36 only includes the fees for downloading, regasification and system access of LNG terminals, but the shipment costs also need to be considered[91]. As mentioned above, in some MSs the projected RPMs foresee discounts at the entry points from LNG facilities into the network in order to incentivise their use. Overall, the access cost borne by the distinct gas sources play their part on final gas supply price formation. However, they may not necessarily restrict upstream competition, as Section 4.5 elaborates in greater detail.

240 Some relevant cross-border tariff changes are expected to occur within the EU once the newly proposed RPMs come into force. Without being exhaustive, as Figure 37 shows, the tariffs at selected German IP sides are projected to increase because of the new postage stamp methodology[92]. This could affect gas wholesale price formation in the neighbouring markets importing gas via Germany[93]. Cross-border exit tariffs from Austria into Italy would also increase. Some relevant tariffs changes could also occur in France, Spain or UK. However, as the concerned NRAs have not submitted the RPMs to the Agency in due time, their impacts could not be analysed in detail. These transportation cost increases could impact future price convergence levels, although this depends on other factors as well. This may be particularly sensible for the markets where the affected IPs set the hubs' marginal supply prices.

241 On the contrary, tariff decreases will occur in selected areas. Many of them will be driven by the competition to attract transit flows to secure revenues after LTCs expiration. To name a recent case, in 2017, the Hungarian exit capacity tariffs and commodity fees were reduced by 22% and 69%, respectively. In parallel, a set of LTCs that delivered gas across Austria and Slovenia into Croatia expired. The revised Hungarian tariffs made supplies across Hungary more competitive than transits via Austria-Slovenia[94]. As a result, several Croatian shippers replaced the Slovenian supply route with bookings via Hungary. According to market analysts, the Hungarian tariff revisions are largely driven by concerns over the continuation of Ukrainian transits in the years to come.

242 Another example of competition can be observed with the inclusion of the BBL interconnector into the Dutch market area, which has removed the booking requirements at the Dutch side of the interconnector and has removed the prior tariffs at the Julianadorp IP. In an initial proposal, the missing IP revenues were redistributed into other points of the Dutch system. However, in line with a suggestion from the Agency, a mechanism was agreed to move some additional revenues generated by BBL back into the Dutch transmission gas system. Since a large set of LTCs expired at IUK in the summer of 2018, the (limited) gas flows from the Continent into the UK have been mostly across BBL, as will be further elaborated.

243 In addition to the revised RPMs, a number of opposing elements will drive the evolution of transportation tariffs in the mid-term. On the one hand, the maturity of the European transportation system has overall reduced the need for infrastructure expansion. With depreciation reducing the regulated asset base, this should reduce the pressure on future average tariff levels. On the other hand, declining demand in the mid and long-term and some forecasted reductions in bookings once LTCs expire may put an upward pressure on tariffs. The combined effects of these trends will have an effect on future tariff levels at EU IPs.

4.5 Relationship between cross-border transportation tariffs and hub price spreads

244 This Section explains the drivers that led to increased convergence of EU gas hubs' prices. It analyses in detail the relationship between cross-border tariffs and hub price spreads. The Section also discusses how current market trends may affect future price convergence.

91 E.g. LNG shipment costs from the US and from Qatar to UK amounts to around 2.0 and 2.5 euros/MWh, respectively.

92 In Germany, all cross-border entries and exits at GPL will be charged 0.37 euros/MWh, whereas all entries and exits at NCG will cost 0.48 euros/MWh (yearly capacity firm products). This also applies now to the IPs between the two German zones, although the market merger could change this from 2022. Single reference prices will entail a redistribution of costs, with higher and lower tariffs. Domestic exits will comparatively decrease.

93 The Italian NRA claims that the German tariff rise could lead to extra costs of 500 million euros per year for the Italian consumers. The French NRA and some TSOs in France and Germany have also expressed concerns along this line.

94 Further price revisions made the Slovenian tariffs favourable again. However, the bookings at the Hungarian-Croatian border had been already secured. See further on the subject at the Slovenian market self-assessment report executed by REKK. See https://www.agen-rs.si/documents/10926/136020/Self-assessment-and-development-options-for-the-Slovenian-gas-wholesale-market/44da7f4e-7a80-4866-bc82-a5c5e33b1ee3.

245 The surge in EU hubs' price convergence levels over the last years has been driven by various interlinked elements. Foremost, market liberalisation and the development of gas hubs drove price convergence. But other specific factors contributed as well. The long-term over-contracting of EU midstreamers is a case in point. The mismatch between demand and historically booked capacity and surplus contracted commodity – strategic for the creation of gas markets – often turned into sunk costs for companies when demand ended up lower than forecasted. Confronted with this situation, affected companies increased inter-hub trading, placing bids around the short-run marginal costs (SRMCs) of inter-hub gas transportation[95]. Given that SRMCs tend to account for a fraction of transportation costs, spreads have tended to fall below cross-border fees.

246 Other market dynamics contributed to keeping hub spreads below tariffs[96]. In some regions, convergence has been supported by suppliers paying similar prices to producers with direct physical access. For example, Norwegian producers tend to offer similar hub-price indexed contracts to NWE buyers that bear similar transportation costs to import gas to the various MSs within the region. As a result, the price difference between Norwegian supplies at each NWE hub is usually below the transportation costs for flowing gas between these hubs. In addition, price convergence is aided by Norwegian producers' delivery of their uncontracted production on the hubs, guided by NWE hubs' spot-price signals. Broad regional accessibility to LNG plays more and more a similar role, although the role and access costs for LNG show a higher variability.

247 In addition, enhanced upstream supply competition has been instrumental. Gas producers may adapt their margins in order to compete in certain markets where they can or want to prioritise market share over margins. To do so, they may strategically price their supplies without fully reflecting the actual transportation costs. For reasons of proximity, Russian supplies face, for example, lower transportation costs to the Baltic or the CEE region than to NWE (e.g. for the latter gas crossing more within-EU IPs). However, Gazprom's supply prices are not necessarily higher in NWE, because Gazprom adapts its prices to the more price competitive environment of NWE, where it cannot set the price. This reinforces price convergence. In the other case, upstream suppliers' price adjustments may not be fully reflected into lower hub prices. Revised contract price conditions could have been granted to the midstreamers' purchasing the gas. However, in the absence of sound competition, they may have not been passed on to the market. Therefore, nurturing sound midstream and retail competition are key to wholesale markets' price integration.

248 In fact, the renegotiation of supply contracts is further pushing towards convergence of sourcing costs among many MSs (see Figure 7). Most gas producers accept hub indexes as bilateral supply price benchmarks. This does not only occur in the EU, but also in Ukraine. Similar supply contracts' terms favour more similar hub prices. The increase in direct sales of gas producers at hubs and enhanced wholesale trading activity, including financial trading, are other contributing factors[97].

249 Historical transportation capacity contracts have started to expire and will continue to do so in the next decade(s). This has prompted a debate on the effect of LTCs expiry on, for example, hub price convergence. Essentially, two views have emerged:

- Price segmentation may re-appear in the absence of SRMC's bidding. As this is an unwanted outcome, regulatory action should be pursued[98].

- Price segmentation will not re-emerge. Similar levels of convergence will be maintained based on fair access rules, sound upstream competition, sufficient interconnection capacity and well-functioning hubs. The consolidation of the AGTM, including regional market mergers, would favour this.

95 E.g. transportation variable charges, trading platforms fees or other operational cost, plus expected profits for engaging in such operations. However, in selected markets, long-term contracts could also have partly hindered the capacity availability, limiting competition.

96 In addition, SRMCs bidding occurs more in some regions than in others; e.g. they are more frequent in NWE than in the Mediterranean area.

97 I.e. the arbitrage of contracts' positions between liquid markets ahead of physical capacity bookings.

98 The European Commission's Quo Vadis study suggested applying harmonised tariffs to all into-EU entry points, and the setting of all within-EU IPs reserve prices to zero pushing tariffs to the outer borders of the EU. The proposal would be accompanied by an inter-TSO compensation fund to secure revenue recovery neutrality.

250 It is acknowledged that a situation where tariffs recurrently exceed spreads will probably limit capacity bookings. This has increasingly been a concern for EU midstreamers, but also for some governments or NRAs. Due to unfavourable business conditions, some EU shippers may not be willing to renew their capacity contracts at some IPs[99]. In addition, non-EU producers are expected to take a more active role in capacity bookings, as initial MMR findings have started to reveal (see Section 4.2). This will also occur because producers will be further requested by EU buyers to deliver gas directly at the VTPs. Some buyers could prefer reducing the risks and complexities that cross-border capacity management may entail. Securing long-term bookings may also offer gas producers the opportunity to sell their uncontracted production on a spot basis.

251 Overall, IPs could tentatively be classified into four different types. This reflects their likely impact on price segmentation and bookings evolution.

- *Core IPs:* IPs that are expected to be highly booked even after LTCs expire. This reflects their high demand. IPs along the main extra- and within-EU supply routes (e.g. Mallnow, OPAL, Tarvisio…) would be of this type. If capacity at those core IPs keeps being held by gas producers and/or midstreamers, the effects of transportation tariffs over supply prices are not likely to deviate from the current situation and would be in line with the competition elements mentioned above.

- *Periodic supply IPs:* These IPs are mainly used to profile seasonal demand and to arbitrage hubs' price differentials. Bookings could become more price responsive and diminish overall. As such, price segmentation could re-emerge between the markets where flows across this type of IPs frequently set the marginal supply price. For example, the two UK-Continental interconnectors (BBL and IUK) would fall into this category. With regard to both, historical contracts recently expired, ending SRMCs bidding. Since then, the relative positioning of spreads and tariffs has further driven their operation[100]. As tariffs are frequently above spreads (the reasons for which are discussed below), new IP bookings have plummeted. In the specific case of interconnectors, a lower convergence level between NBP and Continental hubs could not be observed (yet) (see Figure 28). Flexible Norwegian spot supplies and extra LNG deliveries – together with UK domestic production – were competitive enough to nurture convergence. However, the number of days when the UK-Continental hub spreads exceeded the interconnectors' tariffs, even if still limited, raised year on year. In the absence of SRMCs bidding, IUK and BBL acted sporadically as UK's marginal supply sources. During those days when UK imports from the Continent were needed, NBP prices rose, reflecting the full transportation costs across the interconnectors[101]. Overall, these interconnectors have traditionally been used as an optimisation tool rather than as a primary supply infrastructure. The expiry of LTCs seems further to cement this role.

- *Portfolio optimisation* IPs are likely to remain reasonably booked. These IPs are not likely to be as core to supply but could still be important for managing shippers' positions in adjacent markets; e.g. keeping access to neighbouring UGSs, backing-up intermittent gas power-generation needs or facilitating retail markets' access. This will be more visible in more integrated markets. For example, the expiry of a set of historical LTCs at the Oberkappel IP in Germany in the direction of Austria led to neither lower bookings nor lower convergence between NCG and the Austrian VTP hub. Shippers have replaced long-term bookings with shorter-duration capacity products. In addition, spreads have often remained below tariffs[102]. The reasons are various. The German and Austrian markets are well integrated – i.e. numerous players take positions in both markets seeking to optimise their portfolios. Besides the cross-border IP tariffs are relatively low. This tends to more easily counterbalance the risks of over-contracting capacity with the expected gains of securing it. Marginal supply prices at both hubs are common – i.e. shared upstream suppliers, and similar contracts' indexations. In addition, the limited capacity of Oberkappel implies this IP is not the determining factor for hub price formation.

99 Shippers can still find interest in securing capacities despite the positioning of spreads and tariffs may not seem economical. On the one hand, if gas is not directly purchased at the VTP, they would need booking capacity to the level strictly needed to supply consumers. Capacities can also have an extrinsic value, for example in order to compete in a neighbouring retail market where they seek to obtain higher gains or for shielding the supply flexibility that more intermittent demand of gas for power generation requires.

100 Hubs' price signals - particularly spot ones, although not exclusively - are key drivers. The IPs are also used as a seasonal flexibility tool, for example to access Continental UGS sites. In addition, IP operators are looking into innovative business models; IUK launched an implicit capacity allocation mechanism, which ties cross-border gas purchasing and capacity rights into a one single product.

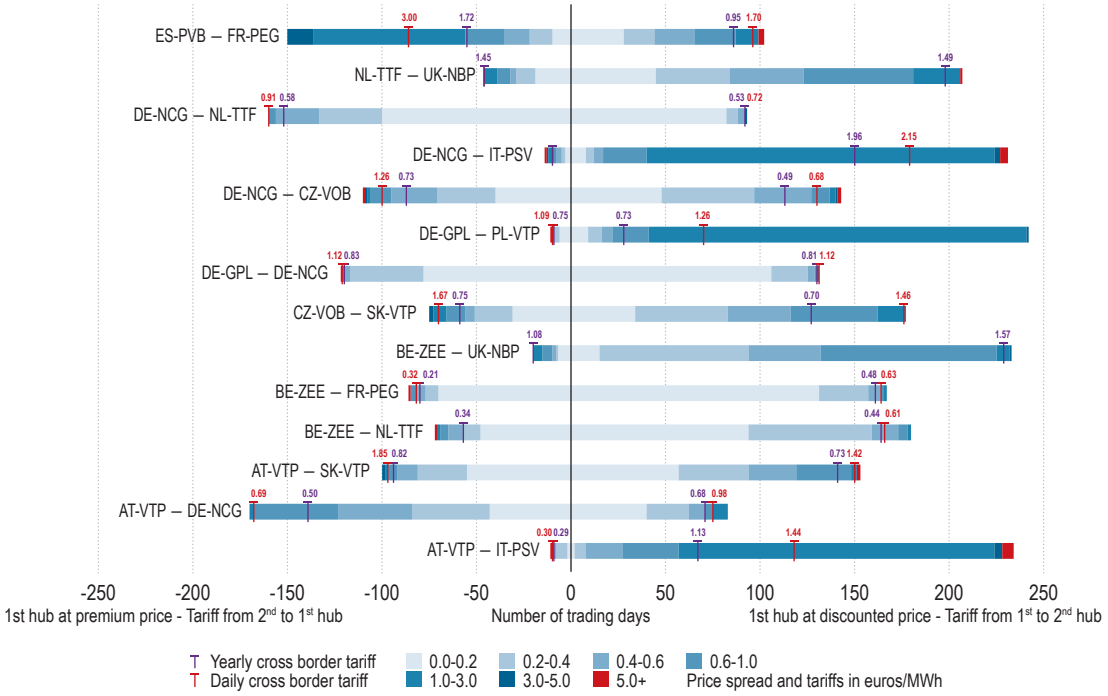
101 In the summer months, there were episodes of NBP quoting at larger discounts. This is because the adding up of the full tariffs across the interconnectors may hinder seasonal gas exports from the UK into the Continent. As a result, the UK may see gas in excess, which puts downward pressure on the NBP prices.

102 The German NCG usually quotes at a discount, although spreads can alter direction along the year.

- *Idle IPs* could experience very low booking levels in the absence of clear supply or price arbitrage roles.

252 Figure 38 shows the relationship between yearly and daily transportation tariffs with spot price spreads. It helps to illustrate how different those values are across the EU hubs.

Figure 38: Day-ahead price convergence levels between EU hub pairs compared to reserve daily and yearly transportation tariffs – 2018 – euros/MWh



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

253 For some hub pairs – e.g. Czech VOB-Slovak VTP, Italian PSV-Austrian VTP, Spanish Mibgas PVB-French TRF (up to November TRS) – the spreads fluctuate within a larger band of the daily and yearly tariffs than for the other hub pairs.

254 The plausible reason might be that the long-term transportation capacity owners place, at times, bids in the higher-priced market at a price which is the result of the less expensive hub's price plus the yearly tariff, adding some margin to it within the upper limit of the daily tariff[103]. As such, less expensive yearly bookings not only shield flow commitments, but also might aid spot prices' arbitrage. This is observed at those hubs with larger differences among the distinct capacity products' prices. For that reason, aligning tariff multipliers would stimulate cross-border spot trade and favour price convergence. The TAR NC sets a maximum multiplier of three for day-ahead tariffs.

255 At present, situations when spreads are above tariffs are generally observed between hub pairs with an insufficient level of competition (in one or both the hubs)[104] and/or where networks are more isolated or not adequately connected. In fact, interconnectivity constraints can be a critical element as they can last for most of the year – exposing more structural limitations – or just occur on certain days[105], following particular market fundamentals.

103 Price spreads exceeding day-ahead tariffs would attract the interest of new players. As such, when limiting the selling price under this threshold, long-term capacity owners may have a competitive advantage.

104 If hubs are competitive, the spreads should not rise significantly above tariffs. Large and all year-continuous spreads expose more structural barriers, from either infrastructure, competition or regulatory nature. The proper implementation of the NCs helps to limit the frequency and magnitude of spreads exceeding tariffs.

105 In accordance to the latest CMP report, 67 IP sides had at least one auction that resulted in an auction premium for the day-ahead products in 2018. The number of contractually congested IP sides in accordance with the longer-term criteria was 44.

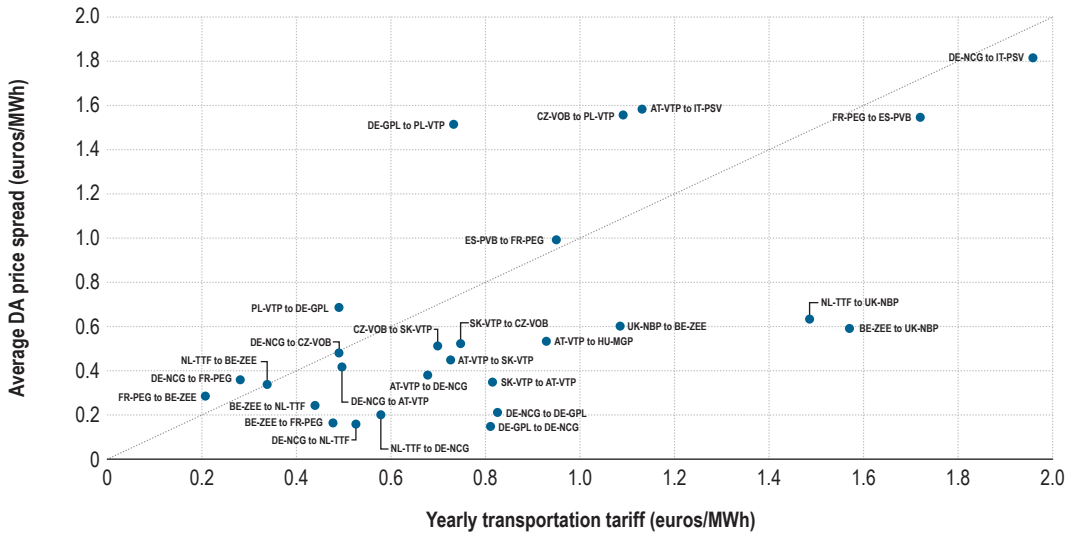
256 For example, the number of days when NCG-Czech VOB or ZEE-NBP spreads exceeded reserve tariffs was minor during the year, but fairly correlated to the presence of premia at capacity auctions; also during most of those days, the entered hub' price incorporated the full transportation costs across the IPs with premia, which acted as *marginal supply* source.

257 On the other hand, at NCG-PSV or the Austrian-Hungarian hub pairs the number of days with day-ahead spreads above daily reserve tariffs was higher. However, for many of those days there were no auction premia – in fact daily capacity was not offered every single day. More recurrent spreads above tariffs seem more the result of structural congestion. The IPs from Germany to Italy passing via Switzerland and from Austria into Hungary are labelled as congested according to the latest report from the Agency about contractual congestion in interconnection points[106].

258 The case of Poland seems of a different nature. Day-ahead spreads between the German GPL and the Polish VPGZ hub often exceed even the daily reserve tariffs, whereas the IPs connecting the MSs are moderately booked[107]. Hub competition in Poland is constrained by a regulation that imposes demanding storage obligations on gas importers[108]. This rule led many companies to cancel their cross-border trading license in 2017 but since then five licenses for international gas trade were issued, including three for entities based abroad.

259 Figure 39 gives an overview of the absolute tariff levels and the price spread between EU hub pairs, in order better to identify concrete cases where spreads above tariffs were more frequent in 2018.

Figure 39: Day- ahead price spreads compared to yearly transportation tariffs – 2018 – euros/MWh



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

106 See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Congestion%20Report%206th%20ed_27052019_FINAL.pdf. The Austrian-Hungarian spread is not shown in Figure 38.

107 Germany-into-Poland direction IPs combined booking rate was less than 45%. In fact, less than 8% of the gas delivered to Poland in 2018 entered via the German or Czech IPs, the least since 2015.

108 The storage obligation rule stipulates that all the Polish importers must have a certain percentage of their natural gas supply either stock, in Poland or abroad.

4.6 Assessment of market effects of Balancing Network Code

260 This Section analyses the potential market effects of the implementation of the BAL NC, focusing on the level of liquidity of the spot markets. The development of short-term (and long-term) liquidity at hubs depends on several structural factors. The BAL NC is deemed to be implemented in markets where short-term liquidity is present and aims to facilitate the further development of these short-term markets. It does this by creating market-based balancing systems and by assigning a residual balancing role to the TSO.

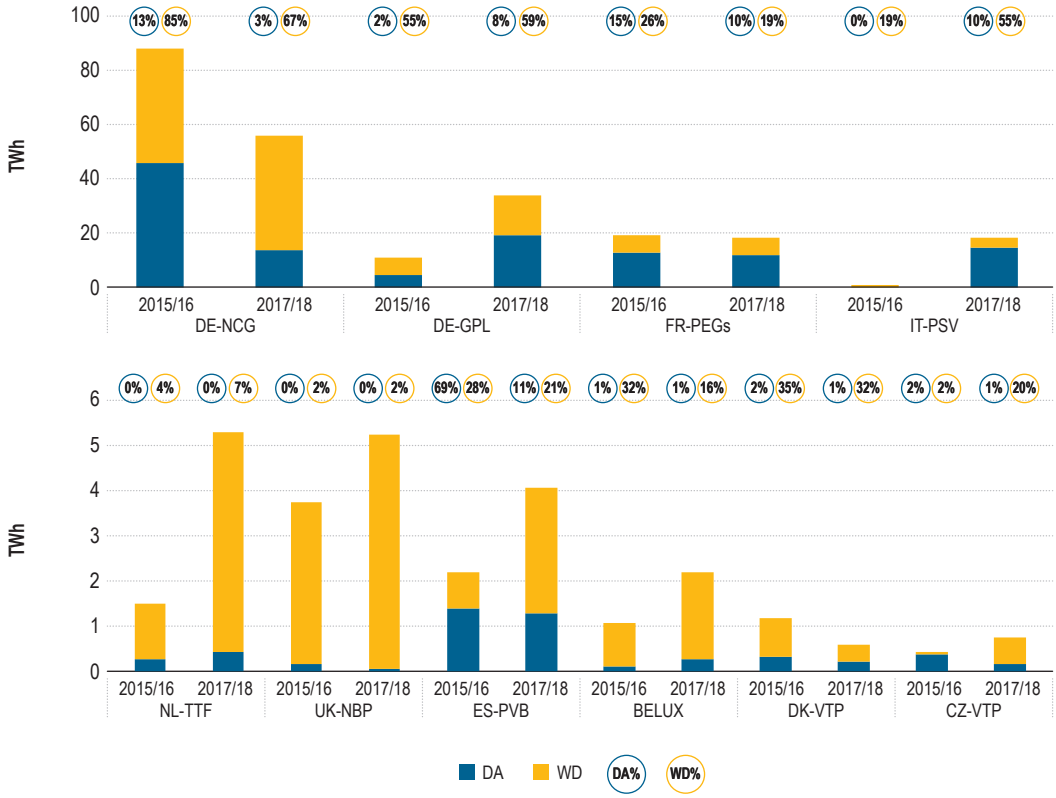
261 The level of short-term liquidity in a zone transcends balancing per se[109]. Other factors influencing the levels of short-term liquidity in a market or balancing zone are, for example, the market economics and fundamentals, the presence of infrastructure capacities, whether a hub is a first mover, the presence of physical and contractual congestions and the presence of barriers in wholesale markets (e.g. excessive or unclear regulation, absence of political support, lack of transparency).

262 An extensive analysis of the level of liquidity of all the gas traded products at EU hubs, and on the drivers behind it, is carried out in Chapter 3. The balancing zones analysed are those where the BAL NC was implemented by October 2015 or by October 2016 and for which complete data could be extracted from the REMIT database[110]. The comparison is made between two gas years, i.e. the 2015/16 gas year, which includes the deadline of October 2015 by when the BAL NC should have been implemented or, for MSs having chosen the transitory measures, it corresponds to the gas year preceding the implementation of the BAL NC, and the 2017/18 gas year. Figure 40 shows the share of TSO volumes for balancing over the total market volumes for spot products during the 2015/16 and 2017/18 gas years at selected balancing zones.

109 For safety and operational reasons, the gas transportation network must be balanced, meaning that the overall volume of gas taken off a gas network shall match the volume of gas entered in it in order to keep the network at the correct pressure. The BAL NC seeks to create a market-based balancing regime by devolving most of the balancing responsibility from the TSO to individual network users. It promotes the creation of balancing markets where: i) TSOs procure products for balancing from network users through market-based procedures and ii) network users trade imbalance positions on a non-discriminatory basis. The desired outcome is that network users are primarily responsible for balancing both their position and the overall system position, and this leaves the TSOs with a small, but critical, residual coordination and management role. The BAL NC also provides some flexibility in order to reflect local physical and commercial circumstances in terms of regulatory preparedness, metering of the gas volumes injected and withdrawn, IT systems and market environment.

110 BeLux (Belgium and Luxembourg), NBP (the UK), NCG and GPL (Germany), GPN (Denmark), TRS (France), TTF (the Netherlands), MIBGAS (Spain), OTE (the Czech Republic), PSV (Italy). The BAL NC was implemented by October 2015 also in the balancing zones in Austria, Hungary and Slovenia and by October 2016 in those of Croatia and Portugal but for these balancing zones complete data could not be extracted from REMIT database.

Figure 40: TSO balancing volumes procured on the DA and WD markets as well as the corresponding TSO share of the total DA and WD market traded volumes at selected hubs for the gas years 2015/16 and 2017/18 – TWh and %



Source: ACER calculation based on REMIT.

Notes: At some hubs, volumes might also include gas procured by TSOs for purposes not strictly related to balancing, e.g. gas for operational purposes. Data for NCG and Gaspool include the volumes procured by the TSOs for quality conversion. Data for the two balancing zones in France (PEG Nord and TIGF) are presented together. Data for the Italian balancing zone only consider STPSs and do not consider the volumes for SOP (Operational Storage) and SNT (TSO-nominated storage) products triggered by the TSO. Data for the balancing zone in the Czech Republic do not consider the flexibility provided by tolerances in place for network users which de facto reduces the exposure of network users to the end of day cash-out so that – within these volume of flexibility – it is not necessary neither for a network user to carry out trades to balance itself during the day or at the end of the day nor for the TSO to trigger balancing actions.

263 In 2017/18 gas year, the TSOs at NBP and at TTF continued to play a very residual role in balancing their systems compared to the other analysed TSOs. Even if the balancing systems of those two TSOs are different, as explained below, they are both market-based as in both zones the TSOs mainly use within-day title products for balancing, while the remaining few volumes for balancing are made of day-ahead title products. All the TSOs' trades are carried out at the respective national exchange, which means that the balancing actions of the TSOs reflect the value of gas used for balancing in the almost real-time. Also, TTF and NBP are the most liquid hubs in Europe also for spot trades, albeit with some differences as TTF leads in the day-ahead volumes while NBP leads in the within-day volumes.

264 The high increase in the liquidity of products traded at TTF, as explained in Section 3.3, also includes the within-day products, the volume of which increased by 100% compared to the 2015/16 gas year. In the gas year 2017/18, TTF was the second liquid hub for within-day trades in Europe and first liquid hub for day-ahead volumes in Europe, which is mainly due to the increased role of TTF as a reference hub in Europe for all the trading timeframes, also the within-day one. The increased trades from market participants, especially within-day, imply that the gas network is more exposed to imbalances, especially within the day, and that as a consequence GTS (the TSO in the Netherlands) triggers more within-day balancing actions to restore the system status to its safety level.

265 GTS implemented the BAL NC one year before the mandatory deadline of October 2015; its balancing system was already among the most market-based and advanced in Europe, mainly due to the almost real-time updates on the system's and on each shipper's status. GTS is the only TSO providing updates on the system every five minutes, compared with the minimum threshold of two updates per day established by the BAL NC. Thanks to the almost-real time updates, shippers are more willing to take short-term positions in the Dutch balancing zone in the spot timeframe, even if the balancing system implemented by GTS has system-wise within-day obligations, rather than full daily balancing as in Great Britain. This shows that a market-based approach adopted by a TSO in general, and in the implementation of the BAL NC, has a positive impact on the development of spot trades in a balancing zone and/or a hub.

266 The balancing system in place in Great Britain, which was implemented already in the 1990s, was used as the reference balancing model for the BAL NC. It consists of a full end-of-day balancing system (with no within-day obligations) where the TSO provides network users with information on the system status four times a day. This should incentivise network users to trade within-day products during the gas day in order to avoid paying the cash-out fee for their imbalance volumes at the end of the gas day. NBP still has the most liquid within-day market in Europe and the within-day volumes traded by the market participants increased by almost 14% compared to the 2015/16 gas year.

267 In Belux the level of TSO intervention in very limited too and a fully market-based balancing system is in place. As for TTF and NBP, also in Belux the TSOs use only within-day and day-ahead products for balancing. Also, the information provision model is very advanced, as the updates that Fluxys (the TSO for balancing for Belux) provides every hour constitute the final hourly allocations, with no need for confirmation on the following day or days. This gives certainty to shippers and incentivises them to change positions during the gas day. The TSO's total trades increased over the years, but they increased less than the within-day trades carried out by the market participants, which increased substantially in the 2017/18 gas year together with the day-ahead trades. The TSO applies a combination of system-wide within-day obligations and an end-of-the-day cash-out system. All those market-based and positive characteristics of the TSOs' balancing system in Belux can be seen in the Figure above, showing volumes of within-day trades in line with the size of the market. The same is true of the more limited TSOs' volumes.

268 At the Danish hub, in the 2017/18 gas year the TSO confirmed its residual role for balancing and procured around half of the volumes procured in the 2015/16 gas year. However, the TSO's share of spot trades remained stable as the overall liquidity in the market decreased as well. In Denmark, only title products are used by the TSO for balancing, and the updates on the system status are provided five times per day. However, the TSO's share of trades in the within-day timeframe is still high, most probably due to the smaller size and limited liquidity of the Danish market.

269 In the 2017/18 gas year, the two balancing zones in Germany - Gaspool and NCG – still had the biggest share of TSO intervention in the within-day market and a significant share of TSOs' intervention in the day-ahead market. This level of intervention also relates to gas quality conversion in both the balancing zones. As for the within-day timeframe, NCG had the largest share (67%) and the largest absolute volumes of TSO trades in the within-day market among all the analysed zones; however, the TSOs' share decreased from 85% to 67% compared to the 2015/16 gas year. On the contrary, at Gaspool, the TSOs' share in the within-day market, and its correspondent absolute volumes, slightly increased compared to the 2015/16 gas year (59% compared to 55%) and Gaspool remained the second balancing zone in terms of TSO intervention among the selected zones, after NCG. In parallel, the share of spot trades carried out by market participants increased in both balancing zones: compared to the 2015/16 gas year, in the within-day timeframe the market's share of within-day trades increased by more than 300% at NCG and by more than 100% at Gaspool and the share of day-ahead trades increased by almost 30% at both NCG and Gaspool.

270 The combined effects of the minimisation of the usage of the balancing platform and of the softening of the portfolio-based within-day obligations are among the drivers behind the increase in within-day trades among market participants at both NCG and Gaspool. Since October 2016, less restrictive portfolio-based within-day obligations apply at both NCG and Gaspool[111]. Also, in the years following the BAL NC implementation, the volumes procured by the TSOs on the balancing platforms in Germany were initially low and then decreased to zero[112]. As such, the TSOs of both the balancing zones decided not to submit a request to the NRA to renew for a further period the utilisation of the balancing platforms. The reason is that the locational products could be successfully procured by the TSOs on the trading platforms as the TSOs' calls for those products were well accommodated by market participants on the trading platform (the gas exchanges). As such, the overall liquidity increased because the presence of the balancing platforms had the effect of splitting the liquidity of the spot trades among several platforms.

271 Contrary to TTF, NBP and Belux, in France the TSO can procure gas for balancing also by using long-term balancing services and flexibility services. As such, the analysis of the TSO's intervention in the balancing zones in France (PEGN and TRS) is limited because the volumes of Figure 40 do not include the TSO's flexibility service ("Alizes"), which is a longer-term hedging product offered to network users in order to cover their potential imbalances at the end of the day. The usage of "Alizes" de facto discourages trades among network users to balance their portfolio with spot products. At the French balancing zones, the information model goes beyond the basic requirements of the BAL NC, as updates are provided every hour; however, the final allocation is received 10 days after the end of the month. The usage of short-term standardised products by the TSOs decreased over the considered period, while the volume of spot trades increased. However, the share of TSO's trades in the spot market is still higher than in TTF and NBP, and the level of spot liquidity is much lower compared to those hubs. The next MMR will be able to analyse whether the merger of the two balancing zones in France –in November 2018 – has improved the liquidity in the spot trades and reduced the TSO intervention. As the liquidity of spot markets in France has increased over the last two gas years, and is very likely to increase even more because of the merger of the two zones, the French TSO and NRA should evaluate whether using only short-term standardised products for balancing would be sufficient, and thus remove the balancing services currently in place.

272 In Italy, the BAL NC was implemented by October 2016 (transitory measure). Compared to the gas year preceding the BAL NC implementation, the market participants' volume of spot trades saw an exponential increase in the Italian balancing zone. Within-day trades increased by more than 230% and day-ahead trades increased by 100%. In parallel, the TSO moved from a mainly longer-term balancing system based on storage to a more shorter-term balancing system based also on other sources of gas (e.g. VTP, IPs, LNG). The volume of TSO's within-day products traded for balancing increased by more than 1,600%. Despite the move to a more shorter-term balancing system and the increased spot market liquidity, the role of the TSO to balance the system seems to be still quite central. This might be due to the relatively recent implementation of the BAL NC. In the next years, the role of the TSO might become more and more marginal as the TSO would progressively increase its experience and confidence in managing the system with the BAL NC tools.

273 The situation of Italy also applies to Spain, where the BAL NC was implemented as well by October 2016. Two years after the implementation of the BAL NC, the market spot trades increased exponentially: the within-day volumes increased by 400% and the correspondent day-ahead volumes increased by more than 1,500%. In parallel, the TSO increased the spot volumes used for balancing, but reduced its share over the total market volumes, mainly due to the end of a series of measures established by the Spanish Government in order to promote the usage of MIBGAS and which involved the carrying out of trades at MIBGAS by the TSO.

111 See MMR covering 2017 and MMR covering 2016 for more information on the amendments to the within-day portfolio-based obligations in the German balancing zones.

112 The balancing platform is an interim measure established by the BAL NC in case a TSO, under the NRA's approval, considers the spot market in its balancing area as not liquid enough. According to the BAL NC, this interim measure should expire by April 2019 but the TSO can submit a request for a renewal for additional five years, subject to the NRA's approval. Both NCG and Gaspool had their balancing platforms until 2018.

274 In the Czech Republic the BAL NC was implemented by October 2016 too. The balancing system in the Czech Republic gives network users updates two times per day on their position and on the system's position, as required by the BAL NC. However, still very few volumes, as a share of the consumption, were traded by the TSO for balancing in the 2017/18 gas year, even if the within-day trades increased compared to the situation before the BAL NC implementation. This could be explained by two factors: i) at OTE, some portfolio-based within-day obligations apply to network users using the pipeline for transit flows; and ii) given the significant volume of linepack available in the transportation network, network users are each given flexibility quantities on each day, depending on the size of their portfolio, which is defined based on the booked capacity at the customer's supply points for the relevant gas day or based on the forecasted annual consumption specific for the relevant gas day. The flexibility quantities reduce the network user's exposure to cash-out and the consequent need for network users to trade volumes in the spot timeframe to cover their imbalances.

List of figures