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ACER
European Union Agency for the Cooperation of Energy Regulators

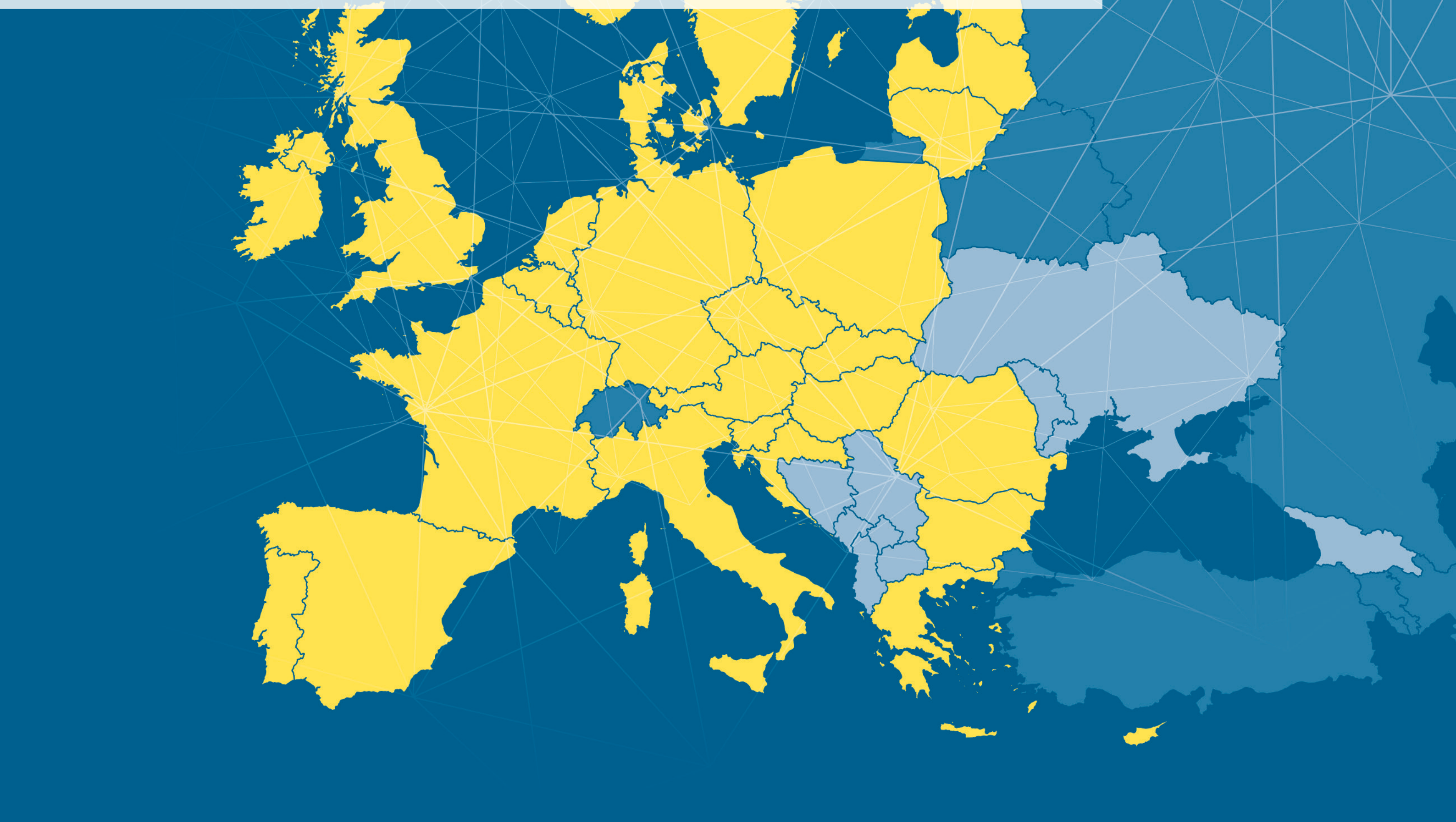
CEER
Council of European Energy Regulators

ACER/CEER

Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2019

Electricity Wholesale Markets Volume

October 2020



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Foreword

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2020 has been a challenging year with the current global health pandemic. Besides our usual comprehensive assessment of developments in the electricity and gas sectors and progress towards the completion of Europe's internal energy market (IEM), this year in our Market Monitoring Report (MMR) we therefore also provide insights on the impact of the COVID-19 on Europe's energy markets.

This MMR (based on 2019 data) comprises three volumes: electricity wholesale markets, gas wholesale markets, and retail markets and consumer rights. The latter now contains the various ACER and CEER reports in one volume. Each volume contains insights on how the pandemic has impacted Europe's energy systems. For example, the retail volume provides an overview of the responses of the National Regulatory Authorities (NRAs) to protect consumers' energy supply and measures to support suppliers. The wholesale gas and electricity volumes report on the unprecedented decline in demand.

Energy regulators keep the lights on and Europe's energy markets working

Keeping the lights on and energy markets functioning is the normal job of the energy regulator. At no time is this role more important than during a global health crisis. Keeping the lights on and hospitals equipment running saves lives. Guaranteeing essential services such as gas, heat and power for household appliances and devices such as laptops enables people to work from home.

Despite the crisis, the electricity and gas market integration process did not stall. This is good news. It also speaks of the value of having integrated well-functioning energy markets.

Building Europe's green recovery and the role of market monitoring

In a post-COVID-19 era, achieving a sustainable and resilient recovery will be a priority. In this context, cost-efficient integration of the internal energy market supported by extensive market monitoring becomes more relevant than ever. Market monitoring captures the status of energy markets and identifies remaining barriers to EU market integration. In particular, the integration of power markets and the decarbonisation of gas are critical to meet the ambitious energy and climate policy targets set for Europe. In our view, the Green Deal is an opportunity to integrate sustainability objectives into Europe's plans to economic recovery.

Key Findings and Recommendations

Europe's clean energy transition must be built on an efficient and well-integrated IEM. Overall, keeping the focus in market integration is key to ensuring the EU energy union targets are met in a cost-efficient manner.

Electricity and gas market integration continued to progress in 2019

Progress in the functioning of Europe's electricity wholesale markets is noticeable, though more advances are needed (in particular, finalising day-ahead market coupling). Available instruments must be utilised to increase the efficient use of interconnectors as required by the 70% cross-zonal capacity target and we are pleased to report that we will soon publish a dedicated report on this. Looking ahead, sizable security of supply benefits are expected as Europe shifts towards a better approach to assess resource adequacy.

Build upon the current gas market framework to decarbonise gas

Gas wholesale markets continue to function well based on the implementation of the current market rules. However, with the European Commission's proposal to reduce emissions further for Europe to be on a responsible path to becoming climate neutral by 2050, as well as the resources earmarked for the EU recovery plan, the currently low uptake of carbon neutral gases will need increased attention. We recommend that any upgrade of the internal gas market rules, targeting an increasingly decarbonised sector, be built on the foundations of the current market framework. This to avoid the transition leading to new national market fragmentations, whilst at the same time retaining the significant benefits for consumers already in place.

Without efficient energy infrastructure investment Europe will not be able to deliver on the ambitious decarbonisation outlook set for Europe's energy sector. ACER and CEER have recently set out a suite of recommendations to improve infrastructure planning and regulatory oversight in our joint ACER/CEER position paper on the review of the TEN-E Regulation. In the joint ACER/CEER Gas Bridge beyond 2025 Conclusions paper we also address important regulatory issues such as power to gas networks or repurposing existing gas networks for hydrogen.

Electricity prices for household and industrial consumers throughout Europe increased in 2019

Retail gas prices also increased for households but they fell for industrial gas consumers. Our monitoring shows that the state of retail markets is more disparate across the Union than for wholesale markets.

Tackling climate change will involve a profound transformation of our economy and will significantly influence the way we use and interact with energy in our everyday life. For the energy transition to be successful, consumers will need to be informed, supported and nudged throughout this transformation. Our market monitoring underlines the importance of ensuring that consumers have ample choice and that their rights are adequately protected, not least the more vulnerable consumer segments. This requires well-functioning retail markets. We are committed to continue monitoring progress towards the completion of a well-functioning internal energy market and to maintain the stability of the energy system as a whole during and after this time of crisis.

We wish to express our sincere thanks to colleagues in the ACER Market Monitoring team and from the NRAs for the expertise and data provided as well as for the contributions of the Energy Community in producing this report.

Enjoy the read. We welcome your feedback.

Christian Zinglersen
ACER Director

Annegret Groebel
CEER President

Executive Summary

Market monitoring relevance in a context of significant shifts and change for European energy markets

1 **The COVID-19 pandemic and its consequent lockdown measures are significantly impacting the energy systems.** For example, an **unprecedented year-on-year decline in EU electricity demand (-7%) was recorded in the first half of 2020** in spite of the measures to ease confinement and restrictions at the beginning of the summer.

2 **Despite the disruption caused by the pandemic, electricity market integration projects did not stall.** On the contrary, many projects have made significant progress. As an example, thanks to the expansion of Single Intraday Coupling (SIDC) to further countries in late 2019, a year-on-year increase in continuous intraday volumes of more than 25% was observed in the first half of 2020.

3 **In the post-COVID era, achieving a sustainable and resilient recovery will be a priority. In this context, a cost-efficient integration of the internal energy market (IEM) supported by an exhaustive market monitoring becomes more relevant than ever.** Market monitoring activities allow to capture the status of energy markets, to measure the impact of energy policies and to identify remaining barriers to EU market integration.

4 **The key findings of the volume on electricity wholesale markets in this edition of the market monitoring report (MMR)** are summarised below. They **show progress in some areas despite the persistence of barriers to the further integration of the IEM.**

5 With regard to the most recent developments, the COVID-19 pandemic accelerated several market trends observed in 2019. **First, the drop in demand due to the COVID-19 pandemic in the first half of 2020 exacerbated the decrease in electricity prices observed in almost all EU markets in the preceding year.** The MMR shows that in 2019, the highest annual average day-ahead prices were observed in the Greek (63.8 euros/MWh), Italian (53.9 euros/MWh), Polish (53.5 euros/MWh) and Romanian (50.4 euros/MWh) markets, whereas Denmark (39.2 euros/MWh), Norway (38.9 euros/MWh), Sweden (38.5 euros/MWh) and Germany (37.7 euros/MWh) recorded the lowest annual average day-ahead prices.

6 **Second, the electricity generation mix was also subject to substantial changes in 2019 and the first half of 2020.** While the first ever switch from coal to gas in terms of the overall share of EU electricity generation was observed in 2019, the first ever switch from fossil fuels towards renewable energy sources (RES) generation, which accounted for 40% of the generation mix, was recorded in the first half of 2020.

7 **Third, the number of negative day-ahead prices in 2019 represented the highest year-to-year increase,** almost doubling the 2018 level. **The COVID-19 pandemic accentuated this increase, almost doubling negative day-ahead prices once more in the first half of 2020.** While the occurrence of negative prices is not a reason for concern in itself and is not necessarily the result of inefficient price formation, an increasing frequency of negative prices stresses the need to efficiently reward market flexibility, including demand side response (DSR), which would contribute to more cost-efficient RES integration in the electricity system.

Further integration of power markets is increasingly important to meet a wide range of high-level policy targets set for Europe

8 **The EU energy policy aims to meet a wide range of policy goals,** including a fully integrated internal energy market, security of supply, improved energy efficiency, innovation, and the development of new and renewable forms of energy to better align and integrate climate change goals into the market. In this context, **the Clean Energy for All Europeans[1] Package** (CEP) adopted in 2019 marked a significant step towards achieving these

1 The Commission's Clean Energy for All Europeans legislative proposal covered energy efficiency, RES generation, the design of the electricity market, security of electricity supply, and governance rules for the Energy Union. Relevant material along with the adopted directives and legislation is available at: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.

goals and **confirmed that the priority for the EU is to decarbonise the economy while maintaining energy security of supply, affordability for consumers and competitiveness for businesses.**

9 In particular, **the EU clean energy transition must be built on an efficient and well-integrated IEM.** Overall, **keeping the focus on market integration is key to ensuring that the EU energy union targets are met in a cost-efficient manner.**

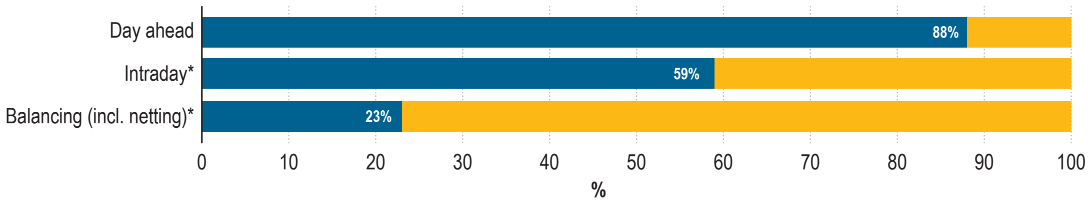
Progress towards market integration was observed in several areas in 2019 and 2020

10 The efforts of Member States towards market integration in recent years continued to bear fruits in 2019.

11 Compared to 2018, the level of convergence of electricity prices was higher overall in 2019. Although price convergence is not an objective in itself, some of the increases in price convergence relate to the further integration of electricity wholesale markets. For example, price convergence increased to 68% in the IU region[2] following the go-live market coupling that took place in October 2018, and to 46% in the CWE region[3] following improvements in the amount of cross-zonal capacity available for trade.

12 End-consumers continued to benefit from the integration of short-term electricity markets. Figure i shows the level of efficiency in the use of interconnectors across different market timeframes, which mirrors the level of progress of the various respective market integration projects across Europe.

Figure i: Level of efficiency in the use of interconnectors in Europe in the different timeframes (% use of available commercial capacity in the 'right economic direction') – 2019



Source: ACER calculations based on NRAs and ENTSO-E data.

Note: For the purpose of this figure, efficient use is defined as the percentage of available capacity (NTC) used in the 'right economic direction' in the presence of a significant (>1 euro/MWh) price differential. Intraday and balancing values (*) are based on a selection of EU borders[4].

13 **Thanks to market coupling, the integration of day-ahead markets,** which are the main reference for trading electricity close to real time, **progressed significantly over the last decade. Consequently, the level of efficiency in the use of cross-zonal capacity (88%) in day-ahead markets was the highest across all short-term timeframes in 2019.**

14 Liquid and well-functioning intraday and balancing markets are crucial to give market participants the ability to balance their positions closer to real time and thus, in turn, facilitate integration of renewable energy sources. **The level of integration of the intraday and balancing markets,** measured in terms of efficiency in the use of interconnectors **is still not as high as in the day-ahead markets, as illustrated in Figure i.**

15 **However, relevant progress in the integration of the intraday timeframe was observed in the past two years** following the go-live of the SIDC in 15 countries in June 2018 and its extension to seven further countries in the course of 2019. For example, a significant year-on-year increase (+ 9 percentage points) in the efficient use of intraday cross-zonal capacity was recorded in 2019. The extension of SIDC to Italy and Greece, expected

2 IU region: the Republic of Ireland and the United Kingdom.

3 Central-West Europe (CWE): Austria, Belgium, France, Germany/Luxembourg and the Netherlands.

4 The EU borders used for the calculation of the intraday efficiency were the following: BE – FR, CH – DE/LU, CH – FR, CH – IT, DE/LU – FR, DK1 – DK2, DK1 – NO2, ES – FR, ES – PT, FR – GB, FR – IT, GB – NL, NL – NO2, SE1 – SE2, SE2 – SE3. The EU borders used for the calculation of the balancing efficiency were the following: AT – CH, AT – CZ, AT – DE/LU, AT – HU, AT – SI, BE – FR, BE – NL, CH – DE/LU, CH – FR, CZ – PL, CZ – SK, DE/LU – FR, EE – FI, ES – FR, ES – PT, FR – GB, HU – RO, HU – SK, PL – SK.

for the first quarter of 2021, and the implementation of pan-European intraday auctions as envisaged in ACER's decision 01/2019[5] are expected to further increase the level of efficient use of cross-zonal capacity in the intraday timeframe.

16 **More room for improvement remains in the balancing timeframe, with a level of efficiency of 23% in 2019.** ACER recently approved a large number of decisions[6] that set out the rules for integrating EU balancing markets and enable transmission system operators (TSOs) to move to the implementation phase of various pan-EU balancing platform projects.

17 Moreover, **well-functioning balancing markets are key to ensuring an efficient overall price formation.** In this respect, the CEP requires the procurement of balancing capacity closer to real time with a view to ensuring that energy prices better reflect the value of scarcity closer to real time. This enables market participants to see the benefits of responding to the immediate market needs while supporting efficient balancing of the system. The MMR shows that **in 2019 the lead-time for procuring balancing capacity in Europe was uneven, with significant room to procure balancing capacity closer to real time in many Member States.**

18 **Accomplishing market coupling in all timeframes across EU borders would render additional welfare benefits of more than 1.5 billion euros per year[7].** A large share of these benefits is expected from the efficient integration of balancing markets, as the level of integration in this market timeframe is still low compared to day-ahead and intraday markets, as highlighted above. Strong commitment and coordination among TSOs are needed in order to ensure an effective and successful implementation of pan-EU balancing platforms, which are currently under development.

19 Additionally, a relevant part of the above-mentioned benefits will be delivered when the borders between Switzerland and the EU are coupled. However, this does not appear to be possible until the conditions envisaged in the CACM Regulation are met: the implementation of the main provisions of the EU electricity market legislation in the Swiss national law and the conclusion of an intergovernmental agreement on electricity cooperation between the EU and Switzerland.

A number of significant concerns and implementation delays remained in 2019

20 A number of concerns and delays, jeopardising the shorter-term achievement of the aforementioned EU energy union's objectives, remained in 2019.

21 The first concern refers to **the implementation of the flow-based market coupling project in the Core region, which involves 13 Member States of Central Europe and has been facing recurrent delays.** The delays are hindering the completion of day-ahead market coupling and more widely, the progress towards truly integrated electricity markets, to the detriment of end-consumers. **The implementation of this project in line with ACER´s decision 02/2019[8] should remain a priority for the TSOs of the Core region.**

22 Moreover, **the incorporation of the Greek borders to market coupling and the integration of the various market coupling projects that still coexist in Europe are also pending.**

23 The second main area of concern refers to **the insufficient amount of capacity available for cross-zonal trade, which led to establishing a minimum level, the '70% capacity target'[9], of cross-zonal capacity in the CEP.** The achievement of such a minimum target presents its own challenges, which are further described below.

5 ACER Decision 01/2019 of 24 January 2019 establishing a single methodology for pricing intraday cross-zonal capacity, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2001-2019%20on%20intraday%20cross-zonal%20capacity%20pricing%20methodology.pdf.

6 All ACER decisions are available at: https://www.acer.europa.eu/m/official_documents/Pages/individual_decision.aspx.

7 Based on calculations performed in previous editions of the MMR.

8 ACER Decision 02/2019 of 21 February 2019 on the Core capacity calculation region TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2002-2019%20on%20CORE%20CCM.pdf.

9 In particular, the CEP requires that at least 70% of the maximum admissible active power flow in critical network elements considering contingencies is made available for cross-zonal trade.

Available cross-zonal capacity and multiple options to meet the 70% minimum target

24 **The CEP identified the lack of sufficient cross-zonal capacity as one of the main barriers to the integration of electricity markets.**

25 **Despite some border-specific improvements** (Poland-Czech Republic/Germany/Slovakia, Austrian borders, Greece-Italy, Bulgaria-Romania and Germany-Denmark), **the amount of cross-zonal capacity made available for trading continued to show significant room for improvement in 2019.** Last year's MMR identified a significant gap between the margin available for cross-zonal trade and the 70% minimum target required by the CEP.

26 While last year's monitoring of the margin available for cross-zonal trade was indicative of the room for improvement prior to the enforcement of the CEP, the 70% minimum target set in the CEP applies as of 1 January 2020. In this respect, **ACER is currently collecting the necessary data to produce a dedicated report on the margin available for cross-zonal trade covering the first semester of 2020.** The separate report will be in line with ACER's Recommendation No 01/2019[10], which aims to provide a harmonised approach to monitoring the achievement of the 70% minimum target set in the CEP.

27 **Member States have a portfolio of instruments available to achieve the 70% minimum target.** This includes short-term measures, such as introducing improvements to the capacity calculation processes, and long-term ones, such as network investments. However, some of these instruments proved to be challenging. For example, **network investments** require careful cost-benefit analysis, and **are often subject to delays** as found by ACER in its latest projects of common interest (PCI) monitoring report[11]. The report also identified that the objective of getting on the PCI list to be eligible for quick implementation and grants is sometimes in conflict with submitting a realistic project plan.

28 **Additionally, the CEP offers multiple shorter-term routes to meet the target:**

- First, **Member States may take transitory measures,** such as action plans or derogations[12], gradually to reach the minimum cross-zonal capacity available for trade by the end of 2025 at the latest.
- Second, **Member States may apply remedial actions,** including topological measures and the activation of redispatching or countertrading. A correct design of the methodologies to coordinate these actions and fairly share the underlying costs is crucial, as further described below.
- Third, **Member States may opt for a reconfiguration of the bidding zones,** as further described below.

10 ACER Recommendation 01/2019 of 8 August 2019 on the implementation of the minimum margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf.

11 The report is available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Consolidated%20Report%20on%20the%20progress%20of%20electricity%20and%20gas%20Projects%20of%20Common%20Interest%20(2020).pdf.

12 ACER compiles all the actions plans and derogations granted, available at: https://surveys.acer.europa.eu/eusurvey/publication/CEP_Derogations_Action_Plans.

The discussions leading to the approval of the redispatching and countertrading methodologies, for which ACER is responsible, are currently ongoing

29 **ACER is currently approving a number of regional methodologies for coordinated redispatching and countertrading[13].** Once implemented, they are expected to increase the ability of relevant TSOs and Member States to efficiently use remedial actions in order to alleviate congestion and avoid unnecessary restrictions to cross-zonal trade. While non-costly remedial actions may also contribute to addressing congestions in an efficient manner, the methodologies aim to ensure that the costs associated with the activation of redispatching and countertrading are fairly shared among Member States, with a view to provide efficient incentives. Finally, the new methodologies will also significantly increase the transparency and understanding of how TSOs optimise the use of available redispatching and countertrading resources.

30 **This edition of the MMR shows a reduction of the costs of remedial actions in 2019, partly explained by circumstantial factors.** For example, the reduction of remedial action costs in Germany was partly related to changes in flow patterns due to a shift in the merit order of generation units, as the costs of producing electricity with gas remained below the costs of producing with coal in 2019, which relieved some congestions.

31 In spite of the eventual reduction observed in 2019, **the costs associated with remedial actions are expected to significantly increase in the coming years, as meeting the 70% minimum target in a context of growing intermittent RES penetration will likely require more significant implementation of remedial actions.**

A bidding zone review process is ongoing, as prescribed by the CEP

32 While changes in the configuration of the bidding zones is politically sensitive, **the potential for substantial socio-economic welfare gains are clear.** Nevertheless, the potential benefits should be analysed together with other effects of a possible reconfiguration of a bidding zone, such as the impact on market liquidity.

33 **The recent split of the German/Austrian/Luxembourgish bidding zones illustrates some of the effects of a bidding zone change:**

- **Some borders experienced a reduction in loop flows together with an increase in the amount of cross-border capacity.** Nevertheless, the benefits from the latter will possibly remain limited until flow-based market coupling is implemented across the whole Core region.

- **The bidding zone split did not appear to negatively affect short-term markets liquidity.** On the contrary, the overall day-ahead traded volumes in Austria, Germany and Luxembourg increased by 5.2% in the first year following the split.

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13 In the period 2019-October 2020 ACER approved the following regional methodologies for coordinated redispatching and countertrading:
ACER Decision 09/2019 of 25 July 2019 on the SEE capacity calculation region TSOs´ proposal for a redispatching and countertrading methodology, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2009-2019%20on%20the%20SEE%20methodology%20for%20coordinated%20RDCT.pdf.
ACER Decision 11/2019 of 26 September 2019 on the request of regulatory authorities of the Core capacity calculation region to extend the period for reaching an agreement on the proposal for the methodology for the coordination and the cost sharing of redispatching and countertrading, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2011-2019%20on%20CORE%20RDCT.pdf.
ACER Decision 14/2020 of 14 July 2020 on Hansa redispatching and countertrading coordination, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2014-2020%20on%20Hansa%20RDCT%20coordination.pdf.
ACER Decision 15/2020 of 14 July 2020 on Hansa redispatching and countertrading cost sharing, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2015-2020%20on%20Hansa%20RDCT%20cost%20sharing.pdf.

At the time of finalising this edition of the MMR, the following methodologies are in the process of approval: Core regional operational security coordination methodology (SO 76), Core common methodology for coordinated redispatching and countertrading (CACM 35), Core common methodology for redispatching and countertrading cost sharing (CACM 74) and SEE common methodology for redispatching and countertrading cost sharing (CACM 74).

- The effects on forward markets liquidity were twofold:
    - **The German forward markets liquidity inherited the high liquidity of the former German/Austrian/Luxembourgish bidding zone.**
    - **The liquidity of the new Austrian forward market is significantly lower although signs of improvement have been observed.** At the same time, Austrian market participants may still combine a liquid German product with transmission rights, or simply use a German product as a proxy for hedging, if this covers their needs.

34 **The CEP provides a new framework for the process of reviewing bidding zones,** including the definition of a methodology, assumptions and alternative bidding zone configurations to be considered for the bidding zone review. The regulatory discussions leading to the approval of all these three aspects of the review are currently ongoing. **ACER will decide on their approval in 2020, just before the start of the upcoming bidding zone review, aiming for a sound, technically grounded and neutral review, so Member States are best equipped to take informed decisions.**

Security of supply: capacity mechanisms and resource adequacy assessments

35 As electricity systems are facing unprecedented changes given political priorities and technological developments, achieving the desired levels of security of supply at a low cost for end-consumers is increasingly important.

36 The CEP aims to address the system adequacy needs in a coordinated manner with a view to maintain the desired levels of security of supply at the lowest possible cost for end-consumers. In particular, the CEP requires a thorough assessment of the adequacy needs in light of the resources available within and beyond one's jurisdiction. ACER plays a crucial role in this respect, as it approves the methodologies[14] underlying this assessment and monitors correct implementation. The approval process of the methodologies is currently ongoing.

37 While ensuring security of supply is a national competence and capacity mechanisms (CMs) may contribute to ensuring such security, **the CEP stipulates that CMs should only be implemented following a robust and realistic resource adequacy assessment and as a measure of last-resort.**

38 In the area of security of supply, the MMR shows that in 2019 a **variety of national CMs remained across Europe. The overall costs of CMs totalled 3.9 billion euros, representing a 73% increase compared to 2018.** The costs are expected to increase further due to CM auctions held in several countries for delivery in 2020 and beyond.

39 As shown in Figure ii, **the ENTSO-E's 2019 Mid-term Adequacy Forecast (MAF) results continued to show, for the 'base case' scenario, no adequacy issues for a number of Member States** that introduced a CM[15], i.e. Bulgaria, Germany, Finland, Greece, Ireland (SEM), Poland, Portugal, Spain and the UK (Great Britain). According to the said MAF results, these MSs do not seem to face an adequacy problem in either 2021 or 2025[16].

40 **A lack of a consistent framework for identifying resource adequacy concerns, emphasises the need for enhanced adequacy assessments, which should, among other aspects, adequately consider the contribution of demand side response and interconnections to adequacy.** Addressing adequacy at pan-European level, including through coordinated and robust adequacy assessments, would yield annual benefits of approximately 3 billion euros[17].

14 Pursuant to Article 23(7) of Regulation (EU) 2019/943.

15 The Greek temporary CM was approved until October 2019 but has been suspended since March 2019.

16 It is important to note that for some Member States, the 2019 MAF results for 2025 are visibly different from the 2018 MAF results for the same year mainly due to different assumptions made in the two versions, e.g. on the evolution of the net generation capacity in 2025, as well as some significant improvements in the methodological framework of the 2019 MAF. This leads to different conclusions with respect to the presence of adequacy issues in the concerned Member States. For more information please see Section 6.3.

17 For more information, please see https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf page 89, where the benefits are estimated in the range of 1.5 to 3 billion euros in 2015, and in the range of 3 to 7.5 billion euros by 2030.

Figure ii: Perceived need for CMs based on the 2019 MAF results – 2019

Source: ACER based on ENTSO-E´s 2019 MAF.

Note: In Greece, CM auctions have been postponed since March 2019 and no CM has been in place since November 2019. In Portugal**, the CM in place has been postponed since 2018. In Spain***, the CM used to comprise "investment incentives" and "availability payments"; the availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016.*

Recommendations

41 **Electricity markets are facing unprecedented changes as they adapt to meet global decarbonisation targets, while safeguarding security of supply and ensuring affordability.** Moreover, the market integration process is at a critical point as the implementation of Regulations and Guidelines establishing Network Codes and Guidelines is still far from completion, while the approval of pan-European methodologies envisaged in the CEP, aiming to improve the functioning of European electricity markets in the upcoming years, is simultaneously ongoing.

42 **ACER is strongly convinced that implementing the policy recommendations proposed in this Volume will also help to address both existing and emerging challenges, with the ultimate goal of ensuring a well-functioning internal electricity market.**

43 These recommendations are grouped into three distinct categories:

- recommendations to increase the limited amount of cross-zonal capacity made available for trading throughout the EU, without which any electricity market integration project is severely hampered;
- recommendations to ensure the completion of the integration process across all electricity market timeframes; and
- recommendations to address adequacy concerns in a coordinated and efficient manner.

44 **The first group of recommendations is aimed at increasing the amount of cross-zonal capacity made available for trading, which is currently one of the most significant factors limiting the integration of electricity markets throughout the EU. In this respect, the recommendations are as follows**

1) **Urgently adopt and implement regional methodologies for coordination of redispatching and countertrading (and related cost-sharing),** as an absolute prerequisite to meet the 70% minimum target.

2) As soon as possible, **amend regional capacity calculation methodologies (CCMs) in order to take into account the requirements of the CEP with particular emphasis to ensure that the 70% capacity target is met.** Moreover, the amendments should consider the aspects for improvement identified in previous editions of ACER's MMR, particularly with regard to the need to guarantee effective transparency, by publishing of the relevant data, of the CCMs.

3) Perform an **unbiased, sound, technical and neutral bidding zone review.**

45 **The second group of recommendations is aimed at ensuring the effective completion of the integration progress across all market timeframes, from long-term to closer-to real time markets. In this respect, the recommendations are as follows:**

4) **Urgently finalise the implementation of single day-ahead and single intraday market coupling. In particular, urgently finalise the implementation of flow-based market coupling in the Core region, involving 13 Member States of continental Europe,** which have faced recurrent delays, and have been hindering the whole market integration process.

5) **Urgently finalise the implementation of the common grid model methodologies** as required by the Regulations establishing the various network codes. Such methodologies are **instrumental to achieve the necessary level of TSOs' coordination,** without which any progress on the aforementioned recommendations is exceptionally difficult.

6) **Effectively and timely implement the Regulation establishing an Electricity Balancing Guideline,** as the integration of balancing markets is increasingly important **to facilitate the integration of growing amounts of RES in the network.**

7) **Implement pan-European intraday auctions for pricing cross-zonal capacity in line with ACER's decision 01/2019[18],** in order to ensure a more efficient use and pricing of cross-zonal capacity closer to real time.

8) **Investigate improvements to the design of forward markets with a view to ensure sufficient hedging opportunities for all market participants,** irrespective of their geographical location.

46 **The third group of recommendations is aimed at addressing adequacy concerns in an efficient manner. In this respect, ACER recommends the following measures, in line with the CEP:**

9) **Perform sound adequacy assessments at the EU and national levels in line with the methodologies for the European resource adequacy assessment and the short-term and seasonal adequacy assessments, which have been approved by ACER[19].** Improvement in the data used as input for the adequacy assessments should also be sought, including data related to demand side response and energy storage potential, and data related to future climate.

10) Only adopt (or maintain) CMs where resource adequacy issues are forecast pursuant to national or European resource adequacy assessments. Moreover, **strive to improve market functioning to ensure improved price signals related to adequacy before resorting to CMs.**

47 As a final recommendation, there is a need for **additional efforts to further improve the quality and the timeliness of the data provided to ACER, including the access to confidential data as envisaged in the CEP.** These efforts are instrumental for ACER's monitoring of key aspects of market integration such as the monitoring of the 70% capacity target prescribed by the CEP[20].

18 See footnote 5.

19 ACER Decision 08/2020 of 6 March 2020 on the methodology for short-term and seasonal adequacy assessments, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2008-2020%20on%20the%20shortterm%20and%20seasonal%20adequacy%20assessments%20methodology_RPR8.pdf.
ACER Decision 24/2020 of 2 October 2020 on the methodology for the European resource adequacy assessment, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2024-2020%20on%20ERAA.pdf.

20 For example, difficulties were found to access the information needed from a TSO in the Nordic Region to monitor the capacity available for cross-zonal trade. Efforts are ongoing, alongside the NRA in question, to obtain this information so as to make the Agency able to carry out its monitoring duties.

1. Introduction

48 The Market Monitoring Report (MMR), in its ninth edition, consists of four volumes, respectively on: Electricity Wholesale Markets, Gas Wholesale Markets, Electricity and Gas Retail Markets, and Consumer Protection and Empowerment.

49 The goal of the Electricity Wholesale Markets volume is to present the results of the monitoring of the performance of the internal market for electricity (IEM) in the European Union[21] (EU), in light of the existing EU Regulation. The performance of the IEM largely depends on how efficiently the European electricity network is used and on how the wholesale markets perform in all timeframes. When electricity wholesale markets are integrated via an optimal amount of interconnector capacity and such capacity is efficiently used, competition will benefit all consumers and will contribute to ensure long-term security of supply (SoS) at a lower cost.

50 The Regulation establishing a Guideline on Capacity Allocation and Congestion Management (CACM)[22] provides clear objectives to deliver an integrated IEM in the following areas: (i) full coordination and optimisation of cross-zonal capacity calculations performed by transmission system operators (TSOs) within regions; (ii) definition of appropriate bidding zones, including regular monitoring and reviewing of the efficiency of the bidding zone configuration; (iii) use of flow-based (FB) capacity calculation methods in highly meshed networks and (iv) efficient allocation of cross-zonal capacity in the day-ahead (DA) and intraday (ID) timeframes. These processes are intended to optimise the utilisation of the existing infrastructure and to provide more possibilities to exchange energy, enabling the cheapest supply to meet demand with the greatest willingness to pay in Europe, given the capacity of the network.

51 The Regulations establishing Guidelines on Forward Capacity Allocation (FCA)[23] and on Electricity Balancing (EB)[24] also play a crucial role in the further integration of the IEM. The former establishes a framework for calculating and efficiently allocating interconnection capacity allowing for cross-zonal trading in forward markets, while the latter sets rules on the operation of balancing markets with the aim to increase the opportunities for cross-zonal exchange of balancing services, increasing efficiency in close to real time operation.

52 The implementation of the provisions included in the above-mentioned Regulations is currently ongoing. First, long-term harmonised allocation rules have been in place since January 2018, while the EU single allocation platform was launched in October 2018[25]. Second, there has been significant progress towards the full implementation of the Single Day-ahead Market Coupling; however, some issues are still pending, in particular the implementation of Flow-based Market Coupling (FBMC) for the whole Core region, the incorporation of Member States (MSs) with markets that are not yet coupled and the integration of various market coupling projects that still coexist in Europe[26]. Third, the second phase of Single Intraday Coupling (SIDC), also called the 'second wave', was launched in November 2019 with the integration of seven countries into the existing intraday cou-

21 The Norwegian and Swiss markets are also analysed in several chapters of this report, but for simplicity, the scope of the analysis is referred to as 'the EU' or 'Europe'. Norway enforces most of the EU energy legislation, including legislation on the internal energy market, and is included in the data reported in several sections of this report. Switzerland has been included in some parts of the wholesale sections on the basis of a voluntary commitment of the NRA. Consequently, the terms 'countries' and 'Member States (MSs)' are used interchangeably throughout this report, depending on whether the particular section/graph also covers Norway and/or Switzerland or not. Several maps included in this report show Kosovo. In this context the following statement applies: "This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo declaration of independence".

22 Commission Regulation (EU) 2015/1222 of 24 July 2015, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN.

23 Commission Regulation (EU) 2016/1719 of 26 September 2016, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R1719&from=EN.

24 Commission Regulation (EU) 2017/2195 of 23 November 2017, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R2195&from=EN.

25 For more information, please see: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/FCA_CACM_Implementation_Monitoring_Report_2019.pdf.

26 There are still two co-existing market coupling regions, the 4M Market Coupling (4MMC) region covering the Czech Republic, Slovakia, Hungary and Romania, and the Multi-Regional Coupling (MRC) region covering, for the time being, the following 21 countries: Austria, Belgium, Croatia, Germany, Denmark, Estonia, Finland, France, Ireland, Italy, Lithuania, Latvia, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia, Sweden and the United Kingdom.

pling region[27]. A 'third wave' is foreseen to go live in the first quarter of 2021[28]. Developments regarding the exchange of balancing energy and balancing capacity, the definition of the relevant terms and conditions or methodologies and the setup of European platforms are also underway.

53 The adoption of the Clean Energy for All Europeans[29] Package (Clean Energy Package, CEP) legislation in June 2019 initiated a period of significant changes fostering the creation of smarter and more efficient electricity markets[30]. The CEP defines an enhanced framework for a well-functioning, integrated market with non-discriminatory participation of all available sources, providing appropriate and affordable SoS while enabling innovation and decarbonisation in line with the EU energy and climate objectives.

54 Moreover, under the new framework, the European Union Agency for the Cooperation of Energy Regulators ('ACER') has an enhanced role in the development, monitoring and surveillance of energy markets, as well as in the area of SoS. ACER's competences are adapted to the new challenges faced by the electricity sector, for example in the context of increased regional cooperation. While the implementation of the provisions included in the above-mentioned regulations remains a key priority for ACER, ACER is well aware that the CEP has become the reference framework for the functioning of the European electricity markets, as explained above.

55 Consequently, ACER is currently working towards enlarging the scope of its market monitoring report in order to adapt to the new requirements of the CEP. On the one hand, ACER will continue the work initiated in last year's MMR on the monitoring of the margin available for cross-zonal trade (MACZT). While last year's monitoring on MACZT was indicative of the room for improvement prior to the enforcement of the CEP, the minimum cross-zonal capacity target set in the CEP applies as of 1 January 2020[31]. In view of this, ACER is currently collecting the necessary data to produce a dedicated report on the MACZT, covering the first semester of 2020. This separate report will aim to identify the scope for improvement to meet the minimum cross-zonal capacity target set in the CEP, and it will be published at a later stage. The Agency will continue to regularly report on the progress made to reach this binding target in the coming years. This separate report will be in line with ACER's Recommendation No 01/2019[32], which aims to provide a harmonised approach on how to monitor the achievement of the minimum MACZT set in the CEP. The harmonised approach aims to support regulatory authorities to monitor the TSOs' compliance with such target, and to facilitate ACER's monitoring of the internal electricity market. ACER aims to publish this report by the end of 2020.

56 On the other hand, ACER is developing methodologies to fulfil additional monitoring duties envisaged for ACER in the CEP[33], i.e. to monitor 'state interventions preventing prices from reflecting actual scarcity', and 'regulatory barriers for new market entrants and smaller actors'. These two areas of monitoring will be progressively incorporated to subsequent editions of the MMR. Moreover, ACER will enlarge the scope of its monitoring in the area of SoS to align it with the requirements of the CEP.

57 This year's volume includes a number of novelties, partly to reflect some of the provisions of the CEP and partly to reintroduce analyses that were temporarily discontinued in the 2018 MMR. First, Section 3.3 includes an analysis on the use of remedial actions used by TSOs to alleviate network congestions and the related costs.

27 For more information on the countries integrated in the first and second waves please see paragraph 128 and footnote 93 in Section 4.3.

28 For more information on the countries that are expected to be integrated in the third wave please see footnote 115 in Section 5.2.

29 The Commission's Clean Energy for All Europeans legislative proposal covered energy efficiency, generation from renewable energy sources (RES), the design of the electricity market, security of electricity supply, and governance rules for the Energy Union. Relevant material along with the adopted directives and legislation are available at: https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.

30 Main legislative documents on the electricity markets, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:L:2019:158:TOC.

31 The CEP requires a minimum level of capacity to be made available for cross-zonal trade. In particular, at least 70% of the maximum admissible active power flow (Fmax) of critical network elements taking into account contingencies (CNECs) shall be made available for cross-zonal trade.

32 ACER Recommendation 01/2019 of 8 August 2019 on the implementation of the minimum margin available for cross-zonal trade pursuant to Article 16(8) of Regulation (EU) 2019/943, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2019.pdf.

33 In particular, these additional monitoring tasks are envisaged in Article 15 of the Regulation (EU) 2019/942 of the European Parliament and of the Council of 5 June 2019 establishing a European Union Agency for the Cooperation of Energy Regulators (recast) (recast ACER Regulation), available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0942&from=EN.

Second, the assessment of the market liquidity across different timeframes has been reintroduced in Chapter 4. Additionally, a case study on the evolution of liquidity before and after the split of the Austria/Germany/Luxembourg bidding zone has been included in this Chapter. Third, a more detailed assessment of balancing markets is presented in Section 5.3 including an assessment of the situation of the lead time for procuring balancing capacity across the EU. Fourth, a preliminary analysis of the technologies currently remunerated through the capacity mechanisms (CMs) is presented in Section 6.2. Finally, a preliminary assessment of the evolution of selected indicators in the first half of 2020 as a result of the COVID-19 pandemic is shown in Annex 2.

58 However, some assessments included in the previous MMRs[34] have been discontinued. Unlike in the 2018 MMR, this report does not include a qualitative assessment of the currently approved capacity calculation methodologies (CCM).

59 As a result of all the developments described above, this year's Electricity Wholesale Markets volume is organised as follows[35]. Chapter 2 presents the key developments in electricity wholesale markets across Europe in 2019. Chapter 3 assesses the level of cross-zonal capacity made available for trade and more specifically the evolution of this capacity within the Central-West Europe (CWE) region, and provides an update of the volumes and costs of remedial actions used by TSOs to alleviate network congestions. Chapter 4 presents an analysis of the evolution of market liquidity across different market timeframes and includes a case study on the evolution of liquidity before and after the split of the Austria/Germany/Luxembourg bidding zone. Chapter 5 outlines an assessment of the efficient use of available cross-zonal capacity across the DA, ID and balancing timeframes. Finally, an update of the situation of the CMs in the EU and their consistency with the perceived adequacy concerns is included in Chapter 6.

34 Previous editions of the MMR, available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-Edition.aspx.

35 To facilitate the reading of the document, the most relevant monitoring methodologies used across this Volume have been compiled into a set of 'methodological papers', which are cross-referenced in the relevant Chapters where those methodologies are applied. These are available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Methodologies.aspx.

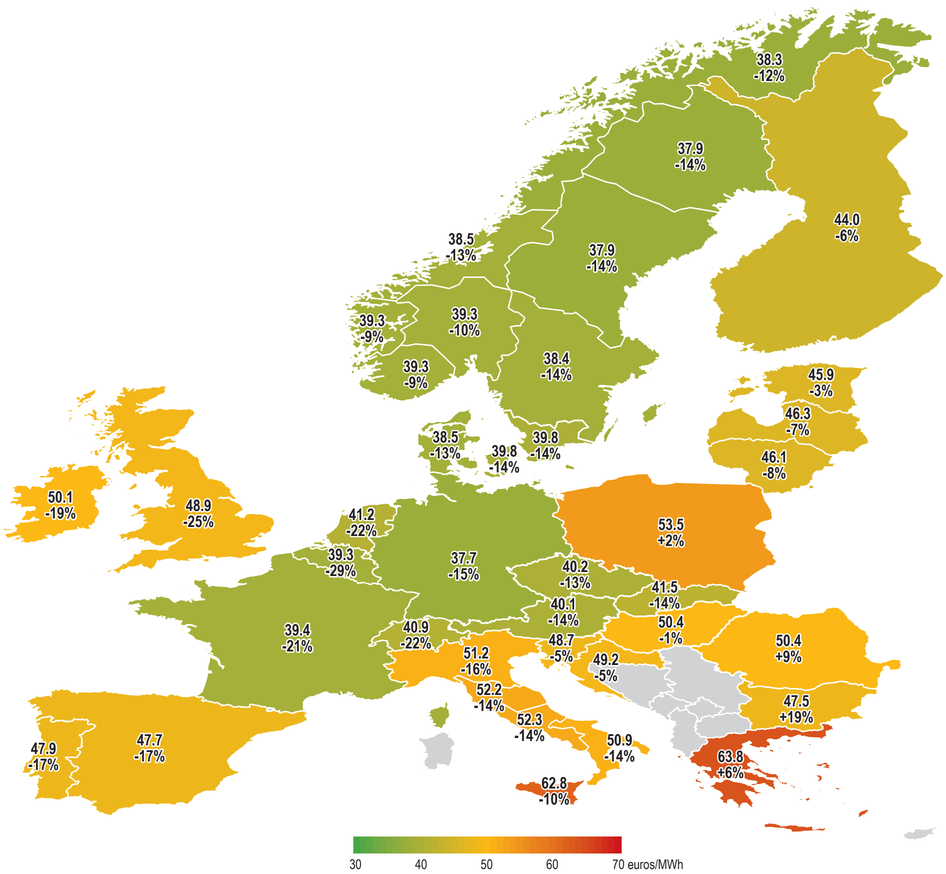
2. Key developments in 2019

60 This Chapter reports on the evolution of DA prices in European electricity wholesale markets in 2019 (Section 2.1) and their main drivers, the occurrence of significantly high/low price periods (Section 2.2), and the level of price convergence within European market coupling regions (Section 2.3).

2.1 Evolution of prices

61 The map in Figure 1 shows the average DA electricity prices in all EU markets for 2019. The highest average annual DA prices were observed in the Greek, Italian, Polish and Romanian markets, whereas the lowest annual DA prices were recorded in Denmark, Germany, Sweden and Norway. In terms of price evolution, Figure 1 shows that the DA price decreased in almost all EU markets with the exception of Bulgaria (+19%), Romania (+9%), Greece (+6%) and Poland (+2%), while the largest drop was observed in Belgium (-29%), Great Britain (-25%) and the Netherlands (-22%).

Figure 1: Average annual DA electricity prices and relative changes compared to the previous year in European bidding zones – 2019 (euros/MWh and % change compared to 2018)



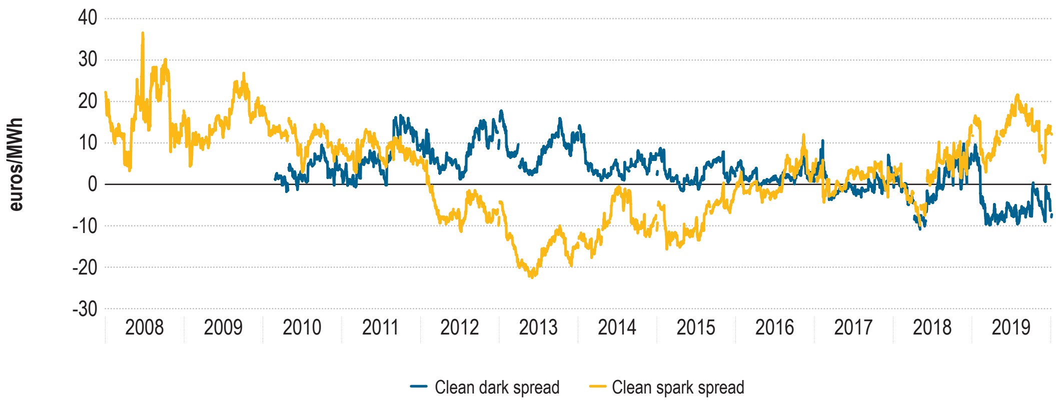
Source: ACER calculations based on data by the European Network of Transmission System Operators for Electricity (ENTSO-E).

62 On the demand side of the market, the main explanatory factor for the overall decrease in DA prices seems to be the decline in the electricity demand. Compared to 2018, the overall electricity demand decreased by 1.3%[36], as a result of milder winter weather[37], returning to the 2016 levels[38]. Notably, the decline occurred independently of the gross domestic product (GDP) which grew in 2019 by 1.4%[39].

63 On the supply side, a combination of factors contributed to the decline in prices. First, the share of renewable energy sources (RES) in the electricity generation mix increased by one percentage point to overall 32% for the EU-28, mostly driven by the increase in wind generation which went up by 11% compared to 2018. Second, in 2019, Europe witnessed a large decrease in gas prices (-41% compared to 2018), driven by the record liquefied natural gas (LNG) imports and stable pipeline flows from Russia[40].

64 At the same time, the CO_2 European Emission Allowance (EEA) prices continued to climb in 2019 (+57% compared to 2018), increasing the costs of producing with fossil fuels, especially coal. Remarkably, in 2019 the profitability of producing with coal dropped below the profitability of producing with gas and remained on average below zero for the first time in the last decade (see Figure 2). Ultimately, the production with coal fell by 21% in 2019 compared to 2018.

Figure 2: Evolution of German month-ahead clean spark and clean dark spreads – 2008–2019 (euros/MWh)



Source: ACER calculations based on PLATTS data.

65 The overall trend of the generation mix is observed in Figure 3, revealing the first ever coal-to-gas switch[41]. Figure 4 displays the year-to-year change in all generation types for 2019.

36 The 2017, 2018 and 2019 demand data are based on hourly load values as published in the ENTSO-E's Transparency Platform. For 2016 and earlier years, Eurostat data (nrg_cb_e: Available for final consumption) were used after applying a correction factor per country. The correction factor, used to ensure time series consistency, was the ratio between ENTSO-E aggregated load values and Eurostat demand data, per country, for 2017.

37 The references to weather information are based on datasets from ECAD (European Climate Assessment Data).

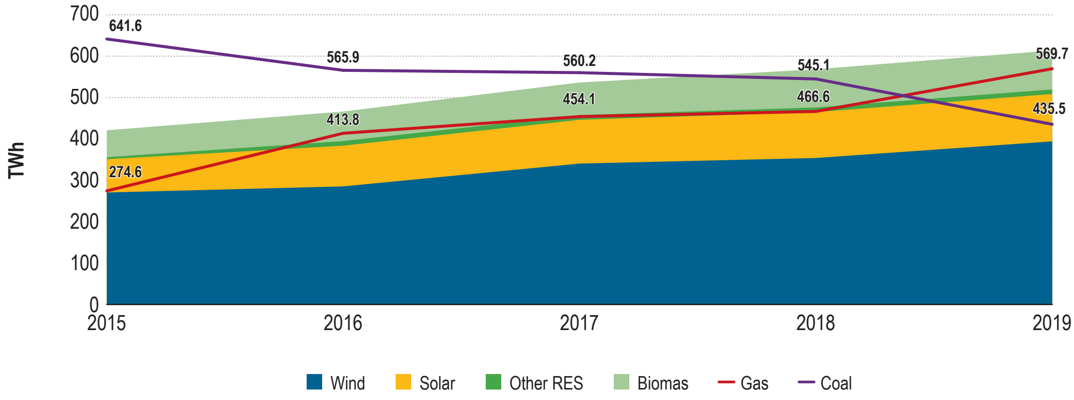
38 The correlation of DA prices with the electricity demand became more apparent in the first months of 2020, due to the SARS-CoV-2 pandemic, causing the majority of the industrial factories to interrupt their energy consumption, which led to a very large drop in electricity DA prices, as presented in Annex 2.

39 More information on GDP growth rates, available at: https://ec.europa.eu/eurostat/documents/2995521/10159272/2-31012020-BP-EN.pdf/435a608a-c9f9-9043-52a1-43ee8cb03d8f.

40 Source: PLATTS. The Dutch Title Transfer Facility (TTF) DA prices for natural gas, the Thermal Coal CIF ARA (Cost, Insurance and Freight; Amsterdam-Rotterdam-Antwerp) 6000 kcal/kg index for coal and the European Emission Allowance DA prices for CO_2 emissions allowances were used.

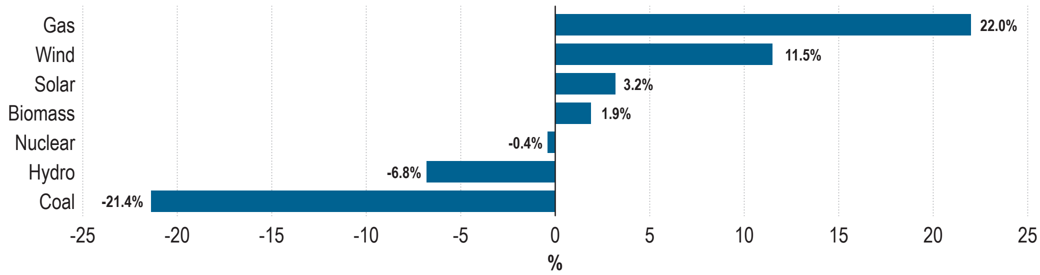
41 For additional information, please see: https://www.iea.org/news/defying-expectations-of-a-rise-global-carbon-dioxide-emissions-flatlined-in-2019.

Figure 3: Evolution of net electricity generation in EU-28 for coal, gas and renewables (excluding generation from hydro) – 2015–2019 (TWh)



Source: ACER calculations based on ENTSO-E data.
Note: Norway and Switzerland are not included in this figure.

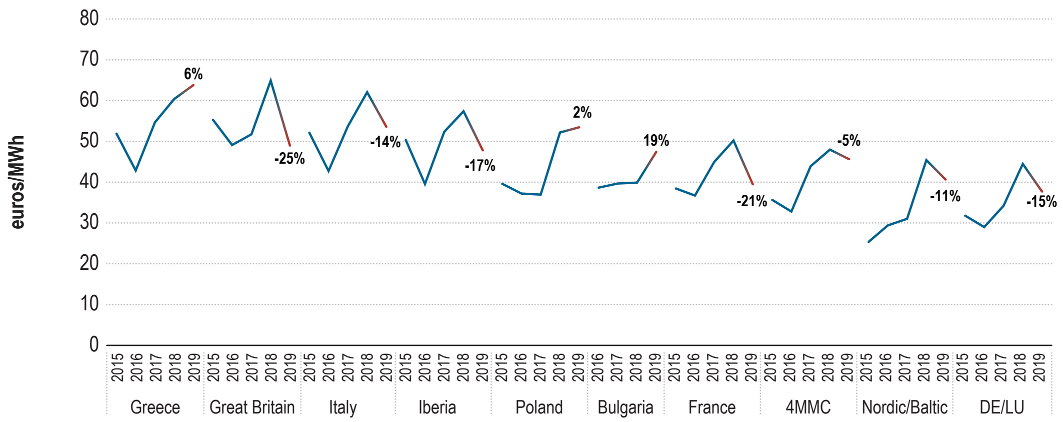
Figure 4: Year-on-year percentage change for the main generation technologies in EU-28 – 2019 (% difference)



Source: ACER calculations based on ENTSO-E data.
Note: Norway and Switzerland are not included in this figure.

66 The analysis of the evolution of annual day-ahead electricity prices over a longer period shows that the decrease in prices in 2019 broke the upward trend of the preceding two years, with the main exceptions of Romania (included in Figure 5 within the 4M Market Coupling (4MMC) price area), Greece, Bulgaria and Poland where prices reached their highest value over a period of at least 8 years.

Figure 5: Evolution of annual DA electricity prices in a selection of European markets – 2015–2019 (euros/MWh)



Source: ACER calculations based on ENTSO-E data.
Note: The figure includes only a selection of the largest markets. The DA prices for the regions 'Nordic+Baltic', 'Iberia' and '4MMC', which is the market coupling in the Czech Republic, Slovakia, Hungary and Romania, are the average of DA prices of the involved bidding zones. The percentages indicate the change in value, compared to 2018.

67 Besides the previously explained factors, other regional or national drivers further explain the evolution of prices in 2019.

68 For example, in Romania, the escalation in prices was largely due to the decommissioning of coal- and gas-fired power plants, which shrunk its total generation fleet by 34%[42]. Similarly, the rise in prices in Greece in 2019 was explained by a remarkable reduction of hydro generation (-33%) in 2019 due to dry weather conditions. In particular, in January 2019, Greece had the highest monthly DA price since 2012, despite the relatively mild winter.

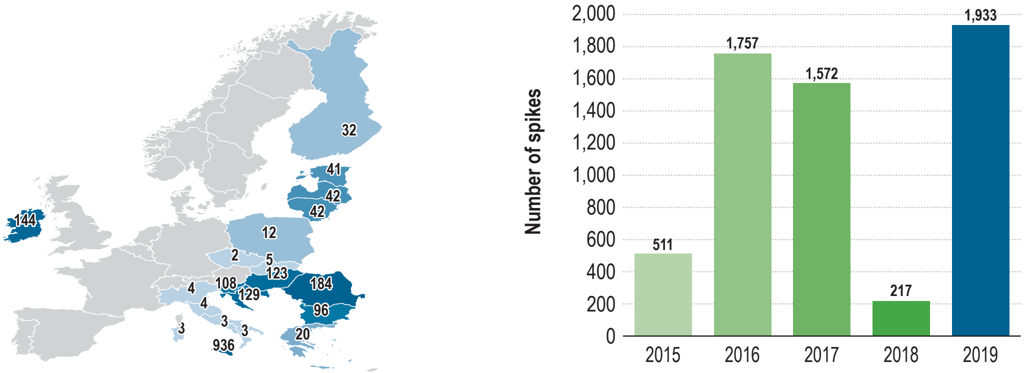
69 At the other end, the recovery of nuclear generation, following extended outages in Belgium, Great Britain and Spain in 2018, contributed to lower prices in these three countries, bringing them back to 2017 levels.

2.2 Price spikes and negative prices

70 This Section reports on the occurrence of periods when prices were significantly high (price spikes[43]) or significantly low (negative) in Europe in 2019.

71 Figure 6 (right) shows that price spikes in 2019 occurred almost 10 times more frequently than in 2018, returning to the 2017 levels. More than half of these spikes occurred in Italy (overall in Sicily), Romania and the Irish single energy market (SEM). In contrast to the previous two years, the 2019 price spikes showed a strong seasonal concentration, with 64% of all spikes observed in the months between August and October[44].

Figure 6: Left part: DA price spikes in the main wholesale DA markets in Europe – 2019 (number of occurrences). Right part: evolution of price spikes in Europe – 2015–2019 (number of occurrences)



Source: ACER calculations based on ENTSO-E and PLATTS data.
Note: For the calculation of the DA price spikes, the virtual bidding zones of Italy are excluded from the calculation.

72 The overall increase in the number of price spikes was largely explained by dry weather conditions and weak hydro generation, thus tightening generation margins and raising prices above 'normal' levels in a majority of East European countries, with either a large average share of hydro production (e.g. Romania and Slovenia) or largely dependent on imports (e.g. Greece, Hungary and Slovakia). The price spikes in the SEM coincided with a period of volatility in the market due to a number of generation outages, in combination with market design changes, in 2019.

73 Conversely, the decrease in the reduction of demand in 2019, together with the recovery of nuclear production (e.g. in Belgium), loosened generation margins and consequently limited the appearance of price spikes in most West European countries (except in Ireland) in 2019.

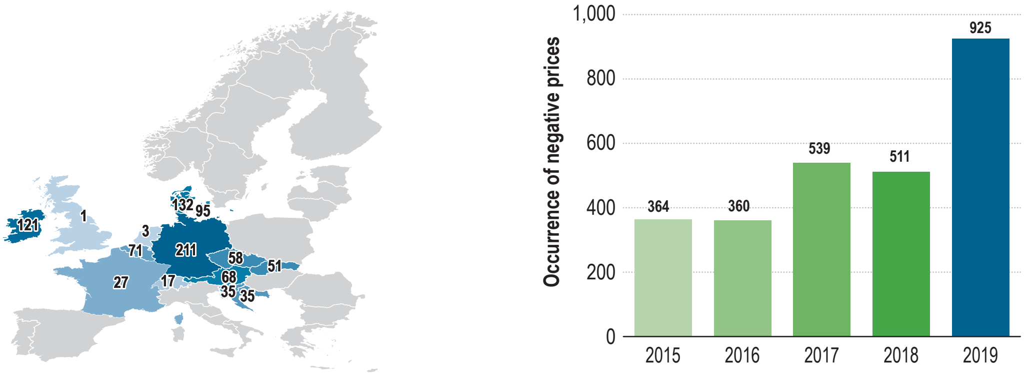
42 Data taken from the ENTSO-E transparency platform.

43 Consistently with the previous edition of the MMR, a price spike is defined as an hourly DA price that is three times above the theoretical variable cost of generating electricity with gas-fired power plants based on the TTF DA gas prices in the Netherlands. See more details in footnote 12 of the Electricity Wholesale Markets volume of the 2015 MMR, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf.

44 Please see Figure 44 in Annex 1 for the monthly evolution of the DA price spikes.

74 At the other end, Figure 7 displays the occurrence of negative prices, which usually take place at times of i) high RES feed-in in combination with low demand and ii) the presence of inflexible generators that are willing to pay for continuing to produce[45] rather than interrupting their production for a short time.

Figure 7: Left part: negative DA prices in the main wholesale DA markets in Europe – 2019 (number of occurrences). Right part: evolution of negative DA prices – 2015–2019 (number of occurrences)



Source: ACER calculations based on ENTSO-E data.

Note: For the calculation of the DA negative prices, the virtual bidding zones of Italy have been excluded from the calculation.

75 In 2019, the number of negative prices showed the highest year-to-year increase, almost doubling the 2018 level. The more profound appearance of negative prices occurred in central Europe, mostly driven by high RES production in Germany and the propagation of below-zero German prices to its neighbouring countries. The highest increase of negative prices year-to-year appeared in the SEM, reaching 121 occurrences, from only four in 2018.

76 An exceptional prolonged occurrence of negative prices in the CWE region took place on 7 June 2019 following a technical failure in the European Power Exchange (EPEX SPOT), which eventually led to a market decoupling[46], affecting Austria, Belgium, France, Germany-Luxembourg, Great Britain and the Netherlands. This restriction to local auctions, in combination with strong supply of wind generation and low weekend demand led to 40 negative price occurrences on that date (considering all markets taken together), representing more than 10% the occurrences in CWE for the entire 2019.

77 Overall, the increasing number of negative prices is related to the increasing penetration of intermittent RES, as long as part of these generators are still subsidised with payments that do not depend on the instantaneous needs of the system[47]. Furthermore, the presence of negative prices emphasises the need to efficiently reward flexibility, including demand side response (DSR), which would contribute to a more cost-efficient integration of RES in the network.

2.3 Price convergence

78 The level of price convergence in DA markets provides an indication of electricity markets integration in Europe. For instance, price convergence is expected to increase following the introduction of market coupling, network expansion, or other actions leading to an increase in commercial cross-zonal capacity. However, reaching full price convergence is not an objective as such, because it would require overinvestment in network infrastructures.

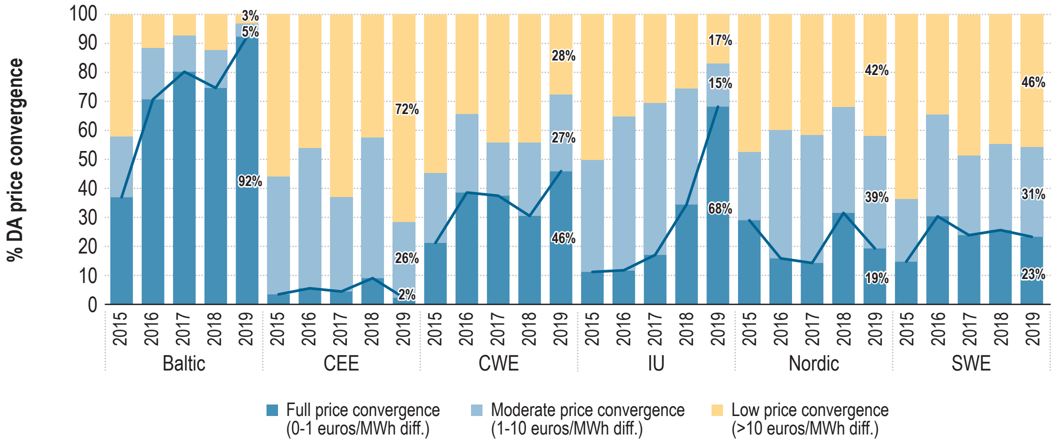
45 Depending on the specific national rules to integrate RES in wholesale markets, some subsidised RES generators could also be interested in paying a certain amount of money for producing, as long as this amount is lower than the subsidy that they receive.

46 More details on the market decoupling event of 7 June 2019 are given in the report established by the NEMO committee, available at: http://www.nemo-committee.eu/assets/files/sdac-report-on-decoupling.pdf.

47 According to the Guidelines on state aid for environmental protection and energy 2014–2020, from January 2016 onwards aid granted to energy produced from renewable sources should be market based, RES beneficiaries shall be subject to standard balancing responsibilities unless no liquid intra-day markets exist, and measures shall be taken to ensure that RES generators have no incentive to generate electricity under negative prices.

79 As year-on-year changes may also be caused by market fundamentals, which are not necessarily related to market integration, price convergence should be analysed over a few years. Figure 8 provides an overview of price convergence[48] within European regions[49] between 2015 and 2019.

Figure 8: DA price convergence in Europe – 2015–2019 (% of hours)



Source: ACER calculations based on ENTSO-E data.

80 In the Baltic region, full price convergence was recorded during 92% of the hours. At the same time, the IU region consisting of a single border (between Great Britain and SEM) has shown a considerable increase in price convergence following the go-live of market coupling, which took place in October 2018[50].

81 Figure 8 also shows a substantial decrease in price convergence for the Central-East Europe (CEE) region, which dropped to 2%. The relatively low cross-border capacity and the lack of market coupling in this area are the main causes behind the marginal level of price convergence in this region.

82 Finally, in the CWE region, where FBMC has been applied since 2015, the number of occurrences of full price convergence in 2019 increased by 15 percentage points as compared to the year before (46% vs. 31%). This increase can be partly explained by the above-mentioned recovery of nuclear generation in Belgium, in combination with the introduction of the 20% minimum remaining available margin (RAM) requirement (April 2018) which increased the cross-zonal trading possibilities in the region.

83 From a wider European perspective, price convergence was overall higher than in 2018. However, there is still room for improvement, especially in the CEE region, where the implementation of market coupling is still pending. Furthermore, the expected improvements in the CCMs and the application of the cross-zonal capacity targets set by the Regulation (EU) 2019/943 on the internal market for electricity (hereafter referred to as 'the recast Electricity Regulation')[51] are expected to further increase price convergence within and between EU regions.

48 Information on price convergence on per border and per capacity calculation region basis is included in Table 5 and Figure 43 respectively in Annex 1.

49 For the purpose of this analysis, bidding zones are grouped into regions, in consistency with the results presented in previous MMRs:
- Baltics region: Estonia, Latvia and Lithuania;
- Central-East Europe (CEE): the Czech Republic, Hungary, Poland and Slovakia;
- Central-West Europe (CWE): Austria, Belgium, France, Germany/Luxembourg and the Netherlands;
- IU region: the Republic of Ireland and the United Kingdom;
- Nordic region: Denmark, Finland, Norway and Sweden; and
- South-West Europe (SWE): France, Portugal and Spain.

50 For the IU region, the price spread is adjusted to reflect the impact of the two high-voltage direct current (HVDC) interconnectors' losses. Details of the effect of these losses are described at: http://www.eirgridgroup.com/site-files/library/EirGrid/I-SEM-Interconnector-Losses-Information-Paper-v1.0.pdf.

51 Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN.

3 Available cross-zonal capacity

84 A well-integrated and efficient IEM relies on sufficient capabilities for cross-zonal trade. Hence the optimal provision of cross-zonal capacity is an essential prerequisite for the IEM to function well.

85 This Chapter first provides an overview of the levels of cross-zonal capacity available for trade (tradable capacity)[52] in Europe, including the evolution of capacity available for trade on borders where the Net Transfer Capacity (NTC) calculation applies (Section 3.1) and, where FB capacity calculation applies (Section 3.2). It also includes an update on the use of remedial actions used by TSOs to alleviate network congestions and the related costs (Section 3.3).

86 As of this year, ACER will also publish a separate report aiming at, first, supporting the regulatory authorities to monitor the fulfilment of the minimum MACZT set in the CEP and second, enabling ACER to monitor the internal electricity market. In particular, in line with its Recommendation No 01/2019, ACER intends to estimate the level of MACZT on critical network elements with a contingency (CNECs) in order to assess whether at least 70% of the maximum admissible active power flow (Fmax) on CNECs is made available for cross-zonal trade.

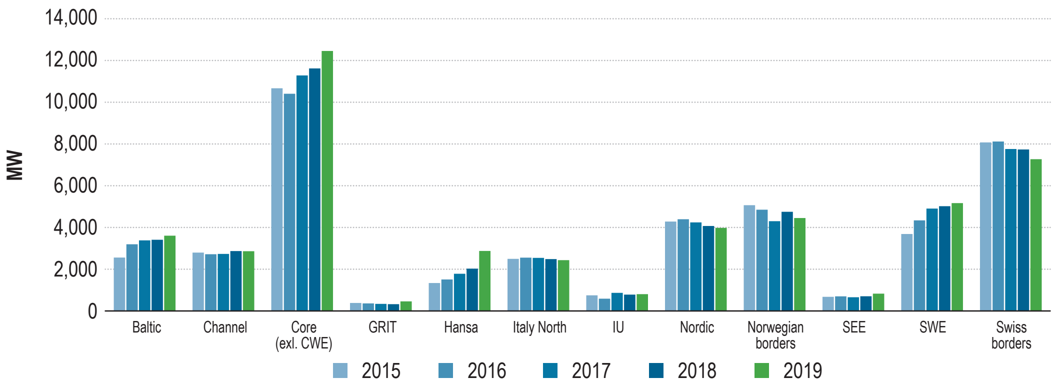
87 The above-mentioned target applies as of 1 January 2020, hence the monitoring of MACZT is not included in this year's MMR which refers to 2019; ACER is currently collecting the necessary data and will produce a dedicated report on the monitoring of the MACZT (covering the first semester of 2020), which will be published at a later stage.

3.1 Evolution of cross-zonal capacity where NTC calculation applies

88 This Section describes the evolution of the amount of cross-zonal capacity made available to the market during the last five years.

89 Figure 9 presents the average cross-zonal DA NTC per capacity calculation region (CCR)[53] from 2015 to 2019, based on hourly cross-zonal capacities made available across all timeframes and all borders of each CCR. The aim of the figure is to identify trends within regions rather than comparing absolute values across regions.

Figure 9: NTC averages of both directions on cross-zonal borders, aggregated per CCR – 2015–2019 (MW)



Source: ACER calculations based on ENTSO-E data.

Note: Only cross-zonal NTC and technical profiles' values are considered in this figure. Bidding zone borders within countries (i.e. within Denmark, Italy, Sweden and Norway) are not included in this figure.

52 Throughout this report, tradable cross-zonal capacity is also referred to as commercial cross-zonal capacity, available cross-zonal capacity or, simply, commercial or available capacity.

53 The Core (CWE) region is not included in this graph, as FBMC is applied. Average NTCs are also displayed for the Norwegian and the Swiss borders.

90 The general increasing trend of the recent years continued in 2019 (+3% compared to 2018), yet with some differences across CCRs. The highest increase occurred at the Greece-Italy (GRIT) region[54] and the Hansa region (both +42%) followed by the South-East Europe (SEE) (+18%), the Core (excluding CWE) (+7%) and the Baltic (+6%) regions, while in the IU and South-West Europe (SWE) regions the NTC increased by 3%. Moderate decreases, compared to 2018, were observed at the Swiss and Norwegian borders (-6%) and at a smaller scale in Italy North and Nordic regions (-2%).

91 The reasons for the above listed variations in cross-zonal capacity are border-specific. Figure 10 shows the major changes in the NTCs on European borders between 2018 and 2019[55]. A description of the factors explaining the most remarkable changes is included below.

92 First, the largest increase in both absolute and relative terms occurred at the technical profile between the Polish borders and the borders of the Czech Republic, Germany and Slovakia (+93% in the exporting direction from Poland and +44% in the opposite direction). The increase was mainly due to the reinforcement of the northern interconnector between Poland and Germany, including the installation of phase shifters that were commissioned during the second half of 2018[56].

93 Second, significant increases in the range between 20% and 40% occurred at a number of borders in the Core (excluding CWE) region, mainly on the Austrian borders. Based on information provided by the Austrian national regulatory authority (NRA), the main reason for the increase was the overall reduction of the system operation uncertainty in this area following the bidding zone split with Germany[57]. Indeed, both the reduction of peak exchange with Germany and the decline of unscheduled flows (UFs) on certain borders[58] contributed to increasing the available cross-zonal capacity on other Austrian borders.

94 Third, the NTC of the high-voltage direct current (HVDC) interconnector between Greece and Italy significantly increased in 2019 (+41%) due to less frequent outages than in 2018.

95 Fourth, after the application of a number of network upgrades to cope with internal congestions issues by the Bulgarian TSO[59], the NTC between Romania and Bulgaria increased significantly (+37%).

96 Finally, the increase at the Hansa region (+20%) was mainly due to the increase in the available capacity between Germany and Denmark (+15% in total compared to 2018). There are two main reasons for the increase. First, the implementation of the schedule to increase cross-zonal capacity between the German and the Western Danish bidding zones pursuant to the agreement between the two countries[60]. Second, a significant increase (+37% in total in both directions) of the capacity at the Kontek HVDC interconnector following long maintenance works and unplanned outages in 2018[61].

54 Here GRIT refers to the Italy-Greek interconnector since bidding-zones within Italy are not part of the analysis.

55 For more information on the evolution of NTC values on all EU borders, please see Table 6 in Annex 1.

56 The installation of phase shifters might also have played a role to the reduction of the unscheduled flows in the region. For more information, please see: https://www.50hertz.com/en/Grid/Griddevelopement/Interconnectorsandphaseshifters.

57 ACER Decision 06/2016 of 17 November 2016 on the electricity transmission system operator´s proposal for the determination of capacity calculation regions, available at: www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

58 For example, compared to 2018, a decrease of 16% in the amount of UFs was observed on the border between Austria and the Czech-Republic in 2019. For more details on the evolution of UFs, please see Annex 3.

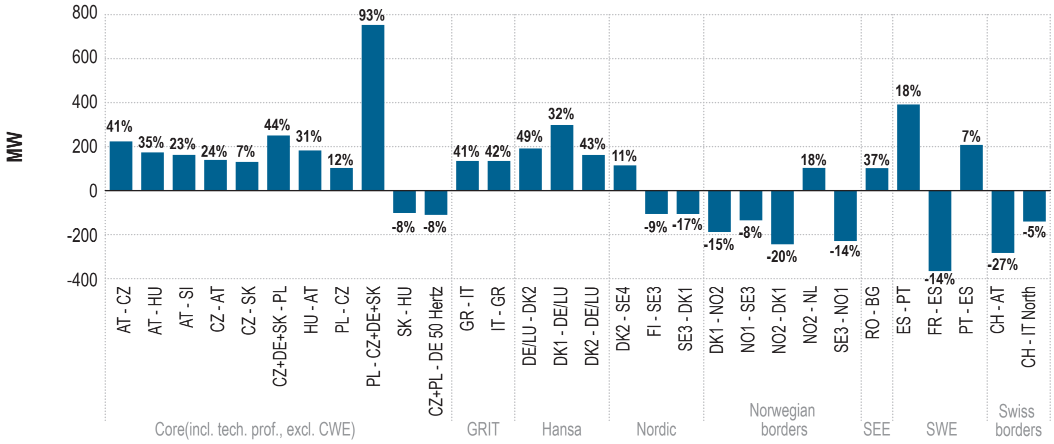
59 Based on communication with the Bulgarian NRA.

60 More information on the joint declaration between Germany and Denmark and the relevant commitments between the TenneT (TSO in the Netherlands and part of Germany) towards the European Commission, are available at: https://en.energinet.dk/About-our-news/News/2019/01/21/guaranteeing-minimum.

61 More information on the unavailability of the Kontek interconnector in 2018, available at: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/SOC/Nordic/ENTSO-E_HVDC_Utilisation_and_Unavailability_Statistics_2018.pdf.

97 At the other end, a decrease was observed at all Swiss borders and directions, except in the export direction from Austria to Switzerland. The highest relative NTC decrease was recorded at the border with Austria in the export direction from Switzerland to Austria (-27%). Similarly, the available capacity was reduced at the Norwegian borders with Denmark (-20% in the direction from Norway to Denmark and -15% in the opposite direction) and in the Nordic region at the Swedish borders with Denmark and Finland (-17% and -9% respectively). A significant decrease in capacity was also observed at the border between France and Spain (-14%). All these decreases were partly related to planned and unplanned outages[62,63]. The decrease at the French-Spanish border related to capacity curtailments for security reasons, following an unplanned outage, during the second and third quarters of 2019[64].

Figure 10: Changes in tradable capacity (NTC) in Europe (excluding differences lower than 100 MW) – 2018–2019 (MW, %)



Source: ACER calculations based on ENTSO-E, NRAs and Nord Pool data.

62 More information on the quarterly reports on 'Availability of transmission capacity in the Nordics', available at: https://www.svk.se/sok/?search-field=transmission+capacity+available+to+the+market.

63 ENTSO-E Transparency Platform.

64 More information on the Joint Allocation Office (JAO) announcements, available at: https://www.jao.eu/news/messageboard/overview.

3.2 Evolution of capacity on borders where flow-based capacity calculation applies (CWE region)

98 In the Core (CWE) region, NTC values have not been relevant since the launch of FBMC on 20 May 2015. An overall indicator for the development of tradable capacity in the Core (CWE) region between 2016 and 2019 is displayed in Figure 11. It shows the monthly average size (i.e. nth root of the volume[65]) of the FB domain in the Core (CWE) region, computed for every hour, but only for the economic direction, i.e. the 'directional size'. The latter is defined for the purpose of this indicator as the FB domain in the orthant[66] which includes the solution of the DA market coupling algorithm, i.e. in the direction corresponding to the bidding zones' net positions[67].

99 Compared to 2018, the directional volume increased on average by 2% in 2019, which partly relates to the introduction of the 20% minimum RAM requirement[68], and the removal of the German external constraints[69] since October 2018[70]. However, a reduction, in the size of the FB domain, was observed during the third and fourth quarters of 2019.

Figure 11: Average size (nth root of the volume) of the directional FB domain in the economic direction in the Core (CWE) region – 2016–2019 (GW)

Source: ACER calculations based on Core (CWE) TSOs data.

Note: The directional FB domain lies in the orthant, which contains the solution of the DA market-coupling algorithm maximising market welfare

65 Initially, the FB domain used for capacity calculation in the CWE region was three-dimensional. The introduction of an additional bidding-zone border between Austria and Germany/Luxembourg in October 2018 added one more dimension, thus leading to a four-dimensional domain. As a result, to ensure comparability, the cubic root of the volume is used up to September 2018, and for subsequent periods the fourth root of the volume is used.

66 An orthant corresponds to a subdivision of an n-dimensional space by coordinate planes (and is equivalent to an octant for a three-dimensional space).

67 For more information on relevant definitions and indicators related to the evolution of capacity on borders where FB methods apply, please see Subsection 3.2.1 on 'Evolution of commercial cross-zonal capacity' (page 24) of the Electricity Wholesale Markets Volume of the 2016 MMR, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf.

68 For more information, please see paragraph 106 of the Electricity Wholesale Markets Volume of the 2018 MMR, available at:http://www.acer.europa.eu/Official_documents/Publications/ACER_Market_Monitoring_Report_2018/15-11-2019%20Corrigendum%20MMR%202018-EW.pdf.

69 According to CACM Regulation Art. 2(6) "'allocation constraints' means the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and [that] have not been translated into cross-zonal capacity or that are needed to increase the efficiency of capacity allocation".

70 See footnote 94 of the Electricity Wholesale Markets Volume of the 2018 MMR.

100 As in recent MMR editions, ACER had access to detailed data on FB capacity calculation in the Core (CWE) region[71]. This data allows to analyse the location and extent to which the constraints related to individual critical network elements (CNEs) limit cross-zonal trade in the Core (CWE) region.

101 Figure 12 describes the share of active constraints[72], with and without taking into account shadow prices[73], per element type and TSO in the Core (CWE) region. The total number of active constraints significantly decreased in 2019 compared to the previous year (-35%), which is consistent with the increased levels of price convergence within the Core (CWE) region (see Section 2.3).

102 The number of constraints linked to internal lines and to cross-zonal lines decreased by -38% and -16%, respectively. At the same time, allocation constrains did not restrict cross-zonal exchange in 2019[74], following the removal of the German external constraints in October 2018[75].

103 Notably, for the first time since the launch of FBMC, the annual share of active constraints linked to internal lines was not higher than the share of constraints linked to cross-border lines (around 50% each in 2019)[76]. This development partly relates to the introduction of the 20% minimum RAM requirement in April 2018, and partly to changes in flow patterns due to a shift in the merit order of generation units. In particular, German coal-fired power plants were frequently replaced by foreign (e.g. gas-fired power plants) generation[77], which relieved some congestions in 2019[78].

104 The overall regional reduction of active constraints was mostly driven by a lower number of active constraints in the Netherlands (a -69% year-on year decrease) and in Germany (-51%). The number of active constraints increased in France, still remaining very limited in number, (nine occurrences compared to only one observed in 2018) and remained mostly unchanged in Belgium. In Austria, a higher number of active constraints was recorded in 2019 but their frequency remained similar to the 2018 levels if only the months after the bidding zone split are considered.

71 The analysis in this Section is limited to the DA timeframe. In the Core (CWE) region, most of the cross-border capacity allocated in the long-term timeframe is not nominated (i.e. the share of long-term nominated capacity in the last two years accounts on average for only between 0% and 2% of all nominations, depending on the border). Moreover, the cross-zonal capacity available for closer-to-real-time timeframes is a residual share of the overall cross-zonal capacity offered. As a result, the conclusions of this Section can be considered as valid for all timeframes taken together.

72 Active constraints refer to the constraints that effectively limit the cross-zonal exchange. Therefore, there is a positive shadow price (see definition in footnote 73) associated with active constraints.

73 The shadow price of a given CNEC measures the market welfare gain resulting from relaxing the capacity constraint on this CNE (i.e. from increasing its RAM) by 1 MW. For more information, see Section 3.1 (pages 21-23) of the Electricity Wholesale Markets Volume of the 2016 MMR.

74 The total number of non-active (i.e. non-binding) allocation constraints decreased by -76% in 2019 compared to 2018.

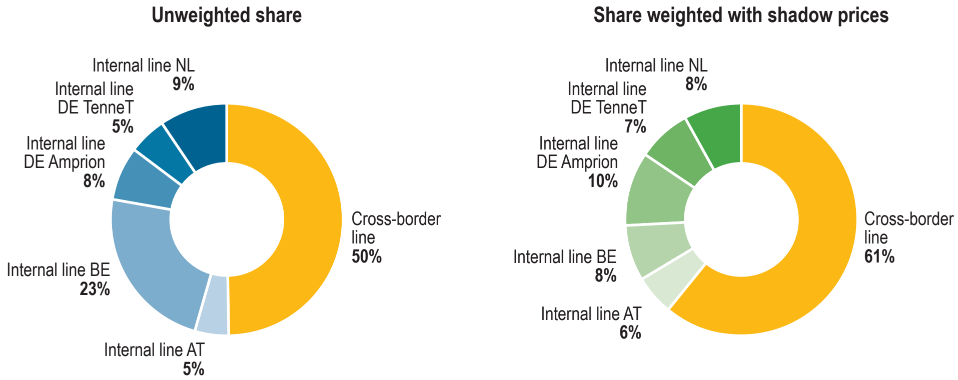
75 See footnote 94 of the Electricity Wholesale Markets Volume of the 2018 MMR.

76 No allocation constraint was active in 2019. At the same time, the total number of declared allocation constraints increased in all TSO areas (+98%, excluding Austria).

77 See Section 2.1 and also Amprion's Market Report 2020 available here: https://www.amprion.net/Dokumente/Dialog/Downloads/Stellungnahmen/2020/AMP_Market_Report_2020.pdf.

78 This also relates to the reduction of remedial action costs, described in Section 3.3.

Figure 12: Share of active constraints in the Core (CWE) domain per TSO control area and category – 2019 (%)



Source: ACER calculations based on ENTSO-E data.

Note: Elements with shares of active constraints weighted with shadow prices below 5% were removed from the pie chart. See Table 7 in Annex 1 for the detailed data.

105 Figure 13 shows the distribution of the minimum hourly RAM[79] over Fmax among all CNECs in the Core (CWE) region, per MSs, in 2018 and 2019. Moreover, Table 1 displays the number of hours with at least one CNEC having a RAM below 20% of Fmax, per MS. The figures show a drastic reduction in the number of occurrences when the RAM remained below 20% of Fmax for at least one CNEC.[80]

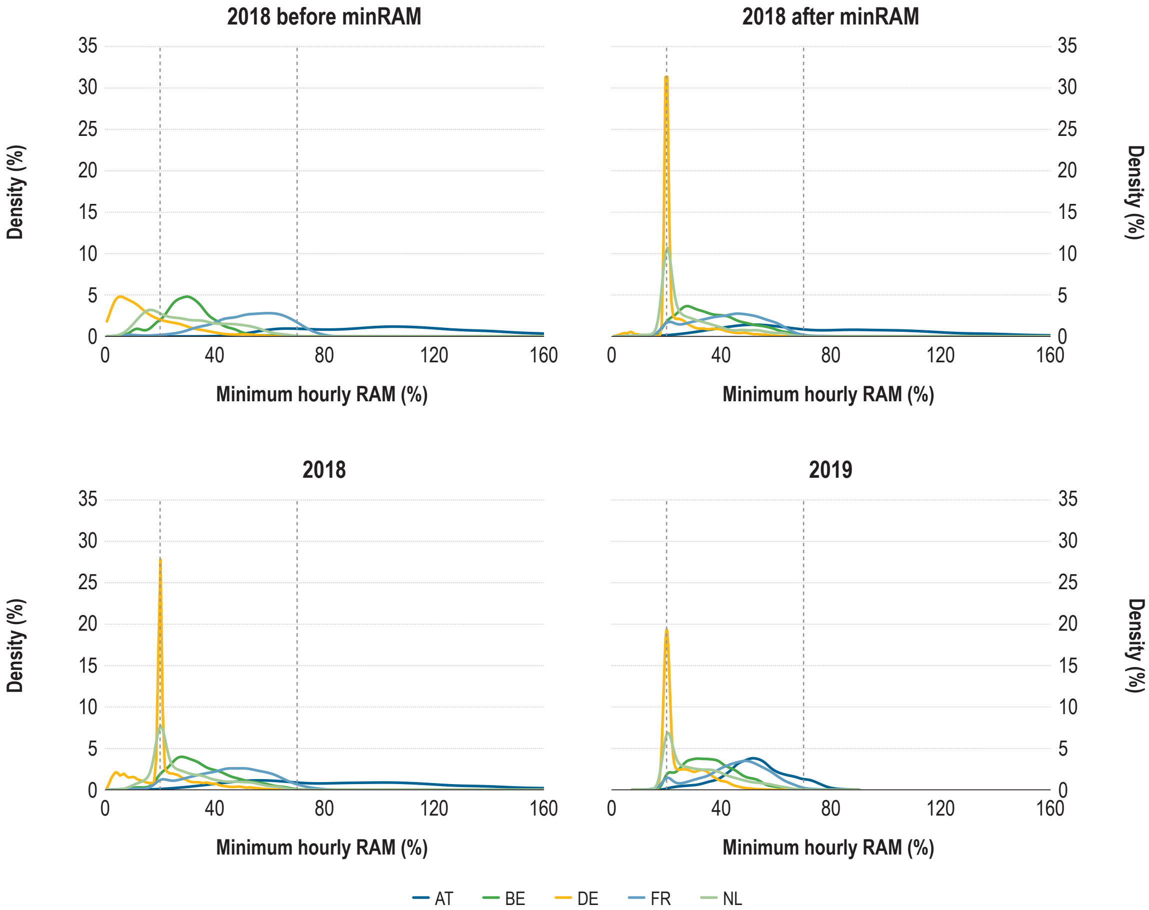
106 Finally, Figure 13 does not enable drawing precise conclusions with respect to the fulfilment of the 70% minimum capacity target. This would require additional consideration of the capacity used to accommodate flows derived from long-term capacity allocation (LTA) and from cross-zonal exchanges beyond the Core (CWE) region (i.e. the margin from non-coordinated capacity calculation, MNCC). As mentioned in the Introduction, ACER will publish a separate report with a detailed estimate of the level of MACZT on CNECs, in line with its Recommendation No 01/2019[81].

79 For the analysis, allocation constraints and CNECs stemming from the application of the long-term capacity allocation (LTA) inclusion patch were excluded.

80 The 20% minimum RAM requirement is subject to operational constraints, allowing further reduction in the capacity made available if system security is endangered. For implementation details please see the latest version of the Documentation of the CWE FB MC solution, available at: www.jao.eu/support/resourcecenter/overview?parameters=%7B"IsCWEFBMCRelevantDocumentation"%3A"True"%7D.

81 See paragraph 86.

Figure 13: Density function of the minimum hourly RAM over Fmax among all CNECs in the Core (CWE) region, per MS – 2018–2019 (%)



Source: ACER calculations based on ENTSO-E data.

Note: The dashed lines mark 20% (minimum RAM requirement as of April 2018) and 70% (minimum MACZT requirement as of January 2020).

Table 1: Number of hours with at least one CNEC with a RAM below 20% of Fmax in the CWE region – 2018–2019

	2018		2019
Member State	before minRAM	after minRAM	
AT	0	2	0
BE	321	30	0
DE	3636	454	13
FR	64	107	51
NL	831	160	0

Source: ACER calculations based on ENTSO-E data.

Note: All the occurrences displayed in the table refer to CNECs that were not actively limiting, i.e. their shadow price was zero.

3.3 Remedial actions

107 This Section focuses on the costs of currently applied remedial actions. These remedial actions relate to the measures taken by TSOs to address the congestions that remain after the market gate closure time (i.e. after day-ahead and intraday market coupling). Some remedial measures do not lead to significant costs[82] (e.g. changing grid topology). Others (e.g. redispatching, countertrading and curtailment of allocated capacity) come at a cost to the system or to TSOs[83].

108 The use of remedial measures in Europe has become frequent and is likely to further increase in the near future for several key reasons. First, bidding zones in Europe are usually defined by political borders, and thus often cannot efficiently address structural (physical) congestion in the network. As a result, locational price signals (via wholesale prices) are partly distorted because these prices do not always reflect the cost of congestion, e.g. within a bidding zone. In the absence of properly defined bidding zones, the volume of remedial actions needed to relieve structural congestion is unlikely to decrease. Second, an increased application of remedial actions will likely be necessary to ensure the fulfilment of the 70% minimum target. Third, as the share of intermittent RES generation is increasing, the location of structural congestion will probably become more dynamic, which may require more TSOs' interventions, sometimes in timeframes closer to real-time.

109 Table 2 shows the evolution of the cost of remedial action during the period between 2017 and 2019. The cost totalled 2.25 billion euros in 2019, which is a 20% reduction compared to 2018 levels.

110 The costs decreased in all MSs except in Austria, France, Hungary and Latvia. Despite the significant reduction (-27% year-on-year), Germany, with more than 1.1 billion euros, accounted nearly half (50%) of the overall costs, followed by Great Britain (19%), Spain (11%), Austria (7%) and Poland (5%).

111 The reduction in the cost of remedial actions in Germany is partly explained by the change in flow patterns as a result of the shift in the merit order of coal and gas generation units[84] and the reduction in the North-South flows due to the introduction of capacity calculation between Germany and Austria. In addition, following the split of the German/Luxembourgish/Austrian bidding zone, Austria started to bear most of the costs for the so-called 'network reserves', resulting in a cost increase in Austria in 2019.

112 In relative terms, the highest costs per unit of demand were observed in Lithuania (5.67 euros/MWh), Austria (2.36 euros/MWh), Germany (2.32 euros/MWh) and in GB (1.89 euros/MWh).

82 However, they may result from long-term investments in the network (e.g. substations or phase-shifters).

83 As of this edition, measures related to the procurement of reserves to cope with network congestion issues are reported under this Section. See footnote 132.

84 See also paragraph 103.

Table 2: Evolution of the costs of remedial actions – 2017–2019

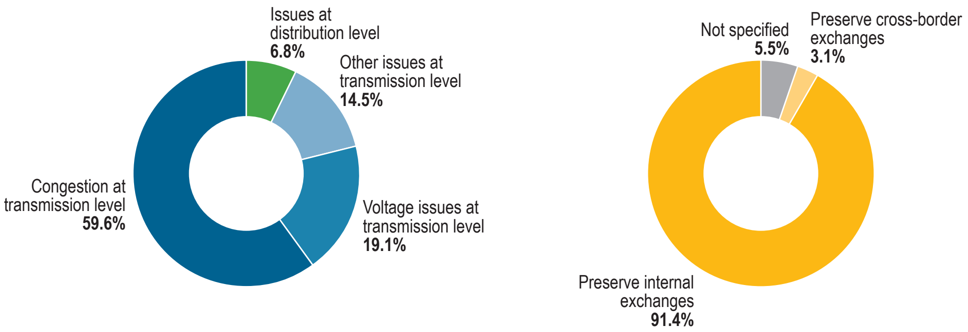
	2019								
Country	Total volume (GWh)	Redispatching (thousand euros)	Countertrading (thousand euros)	Cost of other actions (thousand euros)	Total cost (thousand euros)	Total cost 2017 (thousand euros)	Total cost 2018 (thousand euros)	Relative change 2019/2018	Cost of RAs per MWh of demand 2019 (euros/MWh)
LT	5	0	177	68,833	69,010	35,857	27,683	149%	5.67
AT	2,494	55,400	-22	93,306	148,706	92,405	116,650	27%	2.36
DE	19,341	163,000	63,452	909,656	1,136,107	1,576,469	1,550,386	-27%	2.32
GB	14,127	428,351	242	0	428,592	373,625	465,574	-8%	1.89
ES	7,614	239,610	7,303	0	246,913	371,475	368,743	-33%	0.99
LV	16	0	1,551	4,073	5,624	4,568	6,871	-18%	0.78
PL	15,943	113,666	329	0	113,996	NA	134,354	-15%	0.67
NL	537	31,725	0	29,339	61,064	62,355	65,456	-7%	0.59
EE	30	NAP	871	NAP	871	102	970	-10%	0.11
NO	626	8,630	362	0	8,992	12,523	13,216	-32%	0.07
FR	545	0	24,773	0	24,773	8,583	16,043	54%	0.05
BE	171	2,644	546	123	3,312	2,488	16,880	-80%	0.04
SE	222	2,226	322	0	2,548	5,965	3,664	-30%	0.02
HU	4	511	0	0	511	2,612	227	125%	0.01
FI	24	280	622	0	902	1,756	4,135	-78%	0.01
PT	7	174	0	0	174	44,525	16,764	-99%	0
IT	43	NAP	200	NAP	200	0	6,347	-97%	0
CZ	2	42	0	0	42	602	2,187	-98%	0
Total	**61,752**	**1,046,258**	**100,728**	**1,105,329**	**2,252,338**	**2,816,149**	**2,595,909**	**-20%**	**0.82**

Source: ACER calculations based on NRAs data.

Note: ACER requested data on congestion-related remedial actions. No costs related to costly remedial actions were incurred in Bulgaria, Croatia, Denmark, Greece, Ireland, Luxembourg, Poland, Romania, Slovakia and Slovenia. Switzerland has not provided details on costs. The cost of remedial actions per MWh load is obtained by dividing the total cost by the total demand. The detailed costs of remedial actions is available in Table 8 in Annex 1. Other actions include network reserves in Austria, Germany (including both availability and activation payments) Latvia and Lithuania, cross-border re-dispatching in Belgium, RES curtailment in Germany and the so called "restriction contracts" in the Netherlands (contracts related to the availability for ramping in situations where there is a risk of inadequate capacity available for redispatching, e.g. in case of foreseen maintenance).

113 Figure 14 shows the distribution of redispatching volumes by underlying cause and by objective. First, it indicates that the largest part of redispatching was performed in order to cope with congestions issues at the transmission level. Second, while clearly identifying a single objective for the applied remedial actions is not always possible, it indicates that the large majority of remedial actions are aimed to preserve intra-zonal as opposed to cross-zonal exchanges.

Figure 14: Distribution of redispatching volume by underlying cause (left) and by objective (right) – 2019 (%)



Source: ACER calculations based on NRAs data.

Note: The left chart does not include redispatching costs for Poland and Sweden as the breakdown per cause was not provided.

114 Overall, while a circumstantial reduction in the cost of remedial actions was observed in 2019, the need for TSOs to comply with the 70% minimum target in combination with the increasing share of intermittent RES generation is expected to increase both the volumes and the costs associated with the application of remedial actions.

4 Market liquidity

115 Market liquidity is one of the key indicators of a well-functioning electricity market. An electricity market is considered liquid if a significant number of market participants are able to sell and buy products in large quantities, quickly, without significantly affecting prices and without incurring significant transaction costs.

116 Market liquidity can be measured in several ways. Two of the most frequently used metrics of liquidity are: 1) the 'churn factor', defined as the overall volume traded through exchanges and brokers expressed as a multiple of physical consumption, and 2) the 'bid-ask spread', defined as the average difference between the highest buy offer (bid) and the lowest sell offer (ask) across the trading period of a given product. The first metric provides an indication of the relative 'size' of the market compared to its physical size and it is relevant to all market timeframes. The second metric relates to the costs that market participants may incur when making a transaction and it is mostly relevant to markets based on continuous trading, i.e. most of forward markets and a large share of intraday markets in Europe.

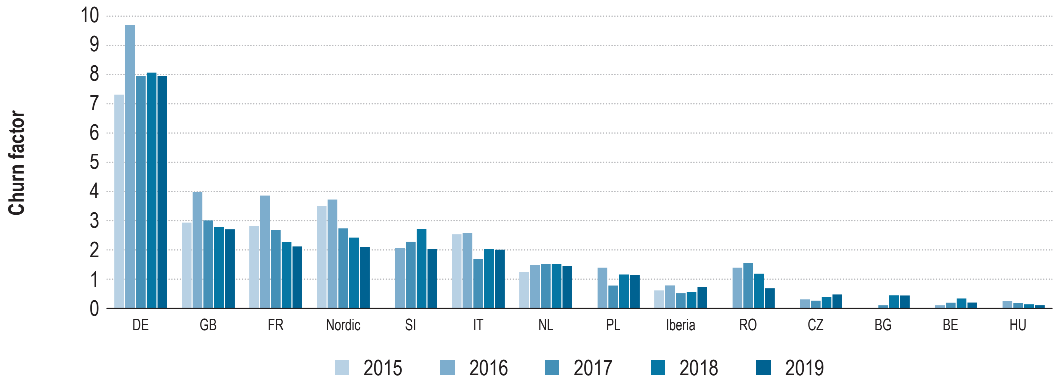
117 This Chapter makes use of these two metrics[85] to provide an update on liquidity in the forward markets across Europe (Section 4.1). The Chapter also includes an overview of European DA and ID markets' liquidity (respectively Section 4.2 and Section 4.3) and a specific analysis on the evolution of liquidity in the Austrian and German/Luxembourgish markets before and after the split of the Austria/Germany/Luxembourg bidding zone (Section 4.4).

4.1 Forward markets liquidity

118 This Section assesses the evolution of liquidity in major European forward markets in recent years.

119 Figure 15 displays the yearly churn factors of the largest European forward markets from 2015 to 2019. It shows that forward markets' liquidity decreased in all major European markets (7% overall decrease), except in Iberia (+29%), and that Germany continued to be the most liquid market in 2019.

Figure 15: Churn factors in major European forward markets – 2015–2019



Source: Volumes from European Power Trading 2020 report, © Prospex Research Ltd and NRAs, and demand from the ENTSO-E Transparency Platform and Eurostat (see footnote 36 in Section 2.1).

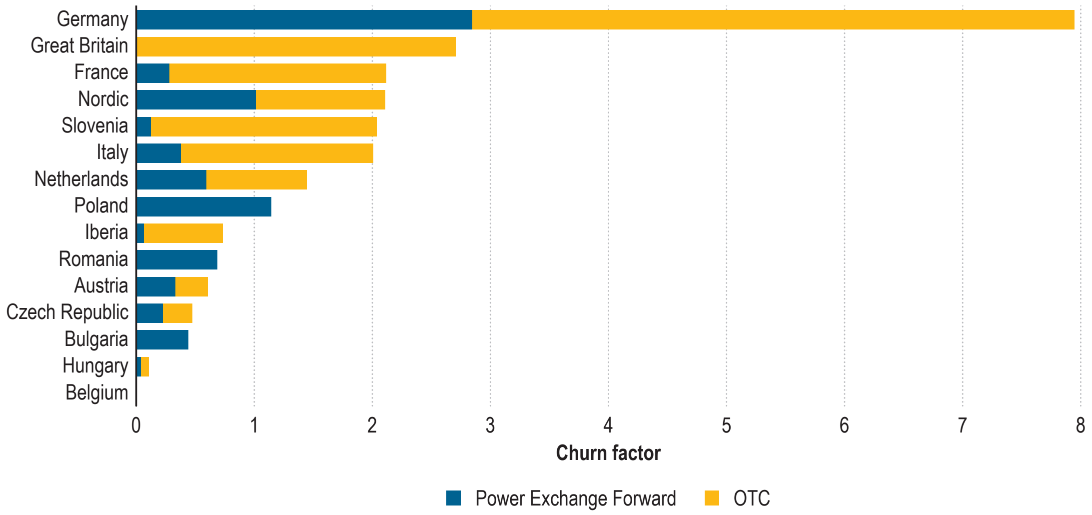
Note: The figure only includes volumes traded or cleared at power exchanges and volumes traded through brokers. For France, Germany, Great Britain, Iberia, Italy, the Netherlands, and the Nordic area, the traded volumes data from 2015 to 2019 were provided by Prospex. For Belgium, Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovenia, the traded volumes data from 2016 to 2019 were provided by the respective NRAs. For Belgium, Bulgaria, Poland, and Romania, the traded volumes are based only on contracts traded at the power exchange. For the Czech Republic, the traded volumes are based only on contracts traded at or cleared by the power exchange, excluding purely bilateral forward volumes.

85 Some metrics have been calculated using anonymised and aggregated data reported to ACER under Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT), available at: https://eur-lex.europa.eu/legal-content/EN/ TXT/?uri=CELEX%3A32011R1227.

120 The evolution of forward markets volumes is unlikely due to a single factor; and some of those factors are country-specific. For example, the decrease in France likely relates to the relative high level of market prices, which have mostly remained above the Regulated Access to Incumbent Nuclear Electricity (ARENH)[86] since Q4 2017. Consequently, independent suppliers may have preferred to source a relevant part of their energy and hedge risks in recent years directly from the ARENH mechanism, rather than in the market. In the Nordic area, the prolonged decrease seems to be explained by a combination of factors, including a more stringent financial regulation[87], a rise in the capacity of renewables, which increasingly use power purchase agreements (PPAs) to hedge its revenues[88], and a growing number of retail customers buying power at contracts indexed to the daily spot price[89].

121 Figure 16 shows the trading volumes per type across the major European forward markets over demand, presenting their divergent structure. While in Great Britain all market volumes are traded over-the-counter (OTC), elsewhere market participants seem to increasingly rely on the power exchanges. In fact, Figure 17 shows a significant overall shift in European forward markets from non-cleared to cleared OTC contracts or trading at the power exchange.

Figure 16: Forward markets churn factor per type of trade in the largest European forward markets – 2019



Source: European Power Trading 2020 report, © Prospex Research Ltd. and NRAs, and demand from the ENTSO-E Transparency Platform and Eurostat (see footnote 36 in Section 2.1).

Note: For France, Germany, Great Britain, Iberia, Italy, the Netherlands, and the Nordic area, the traded volumes data from 2015 to 2019 were provided by Prospex. For Belgium, Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovenia, the traded volumes data from 2016 to 2019 were provided by the respective NRAs. For Belgium, Bulgaria, Poland, and Romania, the traded volumes are based only on contracts traded at the power exchange. For the Czech Republic the traded volumes are based only on contracts traded at or cleared by the power exchange, excluding purely bilateral forward volumes.

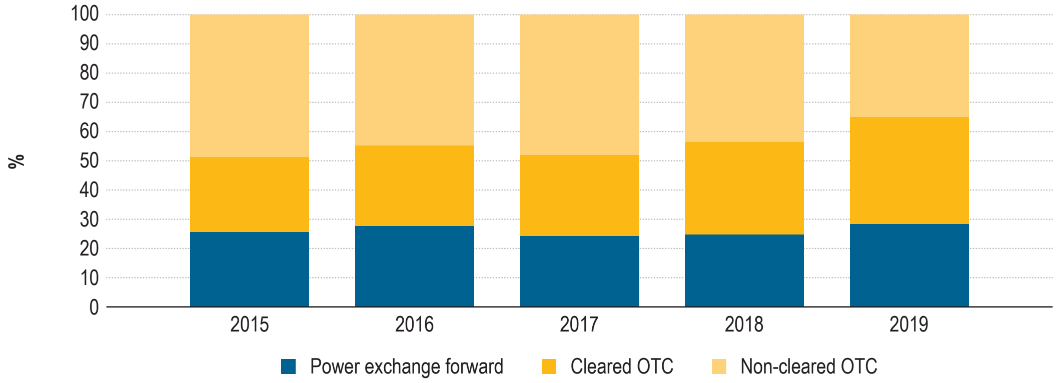
86 ARENH is a right that entitles suppliers to purchase electricity from EDF at a regulated price in volumes allocated by the French energy regulator, CRE. The ARENH price has remained at 42 euros/MWh since 1 January 2012. For more information, please see the related French government's decision, available at: https://www.legifrance.gouv.fr/jo_pdf.do?numJO=0&dateJO=20110520&numTexte=38&pageDebut=08793&pageFin=08793.

87 The impact of financial regulation on the liquidity of forward markets has been mentioned in several studies. For more information, please see Subsections 2.2.4 and 2.2.5 of the "European Electricity Forward Markets and Hedging Products – State of Play and Elements for Monitoring" report, available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ECA%20Report%20on%20European%20Electricity%20Forward%20Markets.pdf.

88 For more information, please see page 7 of the "Changed trading behaviour in long-term power trading; Power Purchase Agreements" report, available at: https://www.mercell.com/m/file/GetFile.ashx?id=108732614&version=0.

89 For more information, please see Subsection 3.3.1 of the report by the Council of European Energy Regulators (CEER) report "Implementing Technology that Benefits Consumers in the Clean Energy for All Europeans Package", available at: https://www.ceer.eu/documents/104400/-/-/bd457593-900f-f995-eac4-ed989255b26f.

Figure 17: Share of yearly traded volumes of selected European forward markets by product type – 2015–2019 (%)

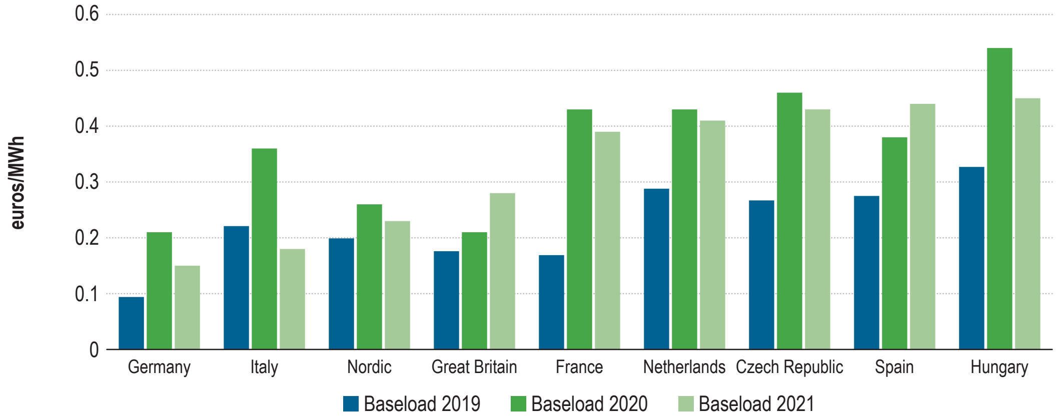


Source: European Power Trading 2020 report, © Prospex Research Ltd.

Note: Volumes from the German, French, Nordic, British, Italian, Iberian and Dutch markets.

122 Figure 18 shows the average bid-ask spreads of OTC-traded yearly base-load products for delivery in 2019, 2020 and 2021 for the major European forward markets. The figure shows that bid-ask spreads of OTC-traded products increased consistently across forward European markets in the past two years, despite an overall slight decrease[90] in the bid-ask spreads of the OTC-traded products for delivery in 2021. The increase is possibly related to the shift in forward market volumes, which are increasingly traded at the power exchange rather than OTC. As the values shown in Figure 18 refer to OTC-traded yearly products, the increased bid-ask spreads are likely the reflection of a lower amount of OTC-traded volumes.

Figure 18: Average bid-ask spreads of OTC yearly products in European forward markets – 2019–2021 delivery (euros/MWh)



Source: ICIS.

Note: Daily bid-ask spreads were averaged out throughout the period from 18 to 6 months before delivery start. For Great Britain, the half-yearly (winter and summer) products were used, and daily bid-ask spreads averaged out throughout the period from 12 to 6 months before the delivery start of each product. For Italy, the bid-ask spread of the base-load product for delivery in 2021 only refers to trades throughout the period from 12 to 6 months before the delivery start.

123 Conversely, bid-ask spreads of products traded at the power exchange followed the opposite trend, i.e. they decreased as the traded volumes increased in 2019 (base-load product for delivery in 2020), e.g. see Figure 24 in Section 4.4, which displays the evolution of yearly products traded at the European Energy Exchange (EEX) for Germany/Luxembourg, Austria and France.

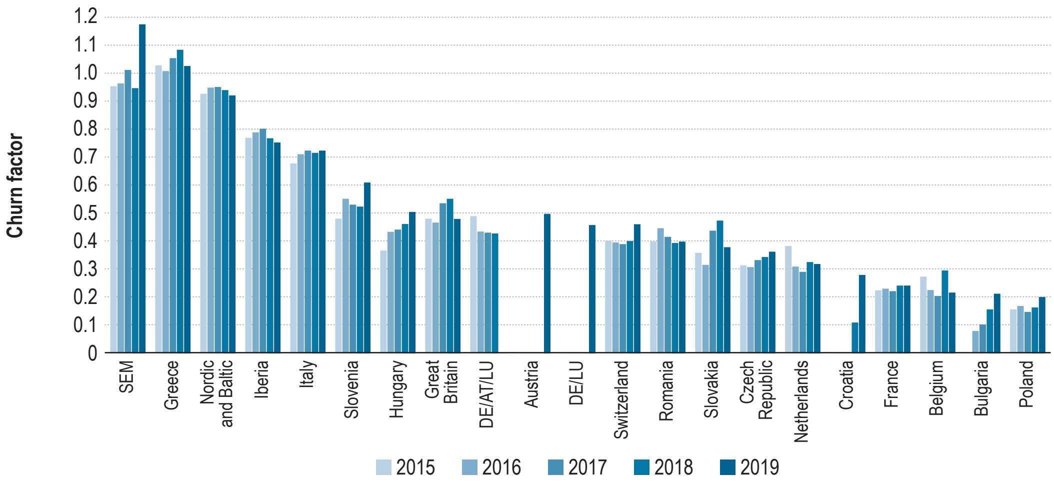
90 This decrease was more pronounced in Italy and Germany.

4.2 Day-ahead markets liquidity

124 Figure 19 shows the evolution of DA markets churn factors across Europe in recent years. It shows very divergent levels of liquidity in Europe, which are often related to differences in market design and market structure. For example, churn factors are equal to one[91] in markets which are exclusive[92] such as in the Single Energy Market of Ireland and Northern Ireland and Greece, while they are lower in markets where a significant share of the energy can be sourced through bilateral contracts or through specific national arrangements such as in France (see paragraph 120 and footnote 86).

125 Moreover, Figure 19 shows that year-on-year changes in DA market liquidity are in general modest, which suggests that DA markets are mature for the largest part of Europe. Some exceptions include markets that emerged in recent years (such as in Croatia and Bulgaria, with year-on-year increases of 154% and 36%, respectively, in 2019), and the increase in DA markets liquidity observed in Germany (together with Luxembourg) and Austria following the split of the German/Austrian/Luxembourgish bidding zone (see Section 4.4 below).

Figure 19: Churn factors in major European DA markets – 2015–2019



Source: Volumes from European Power Trading 2020 report, © Prospex Research Ltd and demand from ENTSO-E Transparency Platform and Eurostat (see footnote 36 in Section 2.1).

Note: Only volumes traded at power exchanges are included.

4.3 Intraday markets

126 This Section provides an update on intraday markets liquidity in European ID markets in 2019.

127 Figure 20 shows the evolution of yearly ID churn factors in major European markets between 2017 and 2019. First, the figure indicates that in 2019 the Iberian Market, Germany, Italy and Great Britain, continued to have the highest ID traded volumes expressed as a share of physical consumption.

128 Second, the figure shows that the upward trend in liquidity levels observed over the past years in most of the countries continued in 2019. The increase is largely related to the go-live of SIDC's first wave on 12/13 June 2018 across 15 countries[93] and its extension to Bulgaria, Croatia, the Czech Republic, Hungary, Poland, Romania and Slovenia, in the second wave on 19/20 November 2019[94]. Overall, the trend is consistent with the growing need for short-term adjustments due to the greater penetration of intermittent generation from renewables into the electricity system.

91 Except deviations due to discrepancies in the data sources used or other aspects such as the inclusion or exclusion of network losses and small producers in the statistics.

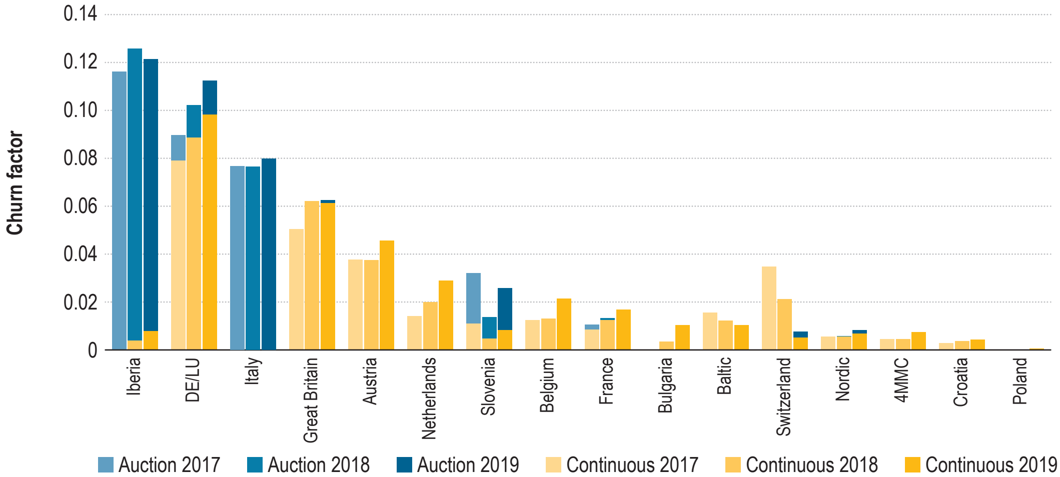
92 'Exclusive' refers to markets which represent the only route to trade ahead of delivery.

93 In particular, the first go-live wave included Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Luxembourg, Norway, the Netherlands, Portugal, Spain and Sweden.

94 More information on the SIDC description, available at: https://www.entsoe.eu/network_codes/cacm/implementation/sidc/.

129 At the other end, ID liquidity continued to pronouncedly drop in Switzerland since the introduction of SIDC (-52% in 2019 compared to the previous year, following a -39% year-on-year change in 2018). SIDC allows for continuous cross-border intraday electricity trading between all integrated bidding zones based on the continuous allocation of cross-border capacities. Because Switzerland – and the Swiss TSO, Swissgrid – does not participate in SIDC[95] and the system that had previously enabled implicit ID trading at the Swiss borders with Germany and France, the Flexible Intraday Trading Scheme, was withdrawn, ID trades with Switzerland now require cross-border capacity to be procured separately[96], with the exception of the Switzerland – Italy North border since mid-April 2019[97].

Figure 20: Yearly ID churn factors in major European markets by type of trade – 2017–2019

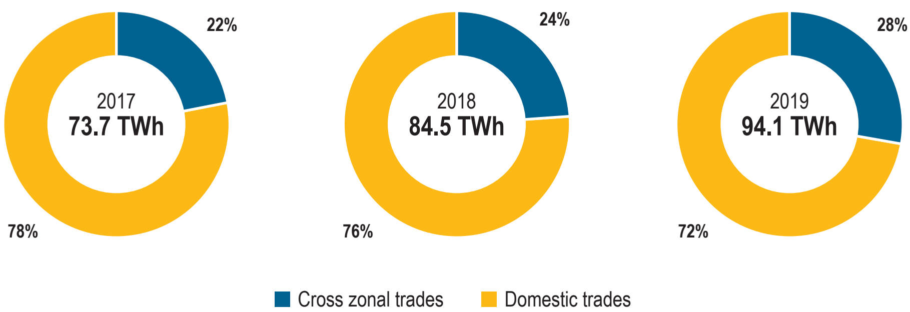


Source: Volumes from nominated electricity market operators (NEMOs) and demand from ENTSO-E Transparency Platform.

Note: Croatia only started its ID market in April 2017, Bulgaria in July 2018, and Poland when it joined SIDC in the second wave in November 2019.

130 An illustration of the benefits of SIDC is presented in Figure 21. It shows the increasing share of cross-zonal intraday trade, expressed as a percentage of the overall continuous ID trading volumes in Europe, following the go-live of SIDC in 2017. Overall, it confirms that SIDC allows market participants to access a larger portfolio of bids and offers to reduce their imbalances and/or support the system's balance in an efficient way.

Figure 21: Share of continuous ID-traded volumes according to intra-zonal vs. cross-zonal nature of trades in Europe and yearly continuous ID-traded volumes – 2017–2019 (% and TWh)



Source: ACER calculations based on NEMOs data.

95 Swissgrid was initially part of the European Cross-Border Intraday (XBID) project; however, since January 2017 it was excluded from the project, due to the intergovernmental agreement on electricity cooperation not having been reached between Switzerland and the EU by the end of 2016 (CACM Article 1 (4) & (5)). More information on the XBID project Q&A, available at: https://www.nordpoolspot.com/globalassets/download-center/xbid/xbid-qa_final.pdf.

96 For more information, please see pages 15 and 16 of the "Market Transparency 2018" ElCom Report, available at: https://www.elcom.admin.ch/dam/elcom/en/dokumente/2019/Markttransparenz%202018.%20Bericht%20der%20ELCom.pdf.download.pdf/Market%20Transparency%202018.%20ElCom%20Report.pdf.

97 Implicit ID auctions for the Switzerland – Italy North border went live on 17/18 April 2019. For a more detailed description see Terna's news publication, available at: https://www.terna.it/en/electric-system/publications/operators-news/detail/go-live-of-implicit-intraday-auctions-on-swiss-italian-border-20190410.

4.4 Case study: Evolution of liquidity before and after the split of the German/Austrian/ Luxembourgish bidding zone

131 On 1 October 2018, and following the ACER Decision 06/2016 on capacity calculation regions[98], the former bidding zone comprising Austria, Germany and Luxembourg was split into two bidding zones: Germany/Luxembourg and Austria. While the trigger for this split was the need to manage network congestions in the area by means of cross-zonal capacity allocation, the evolution of market liquidity in the German/Luxembourgish and Austrian markets following the split has often been regarded by stakeholders as an area of concern.

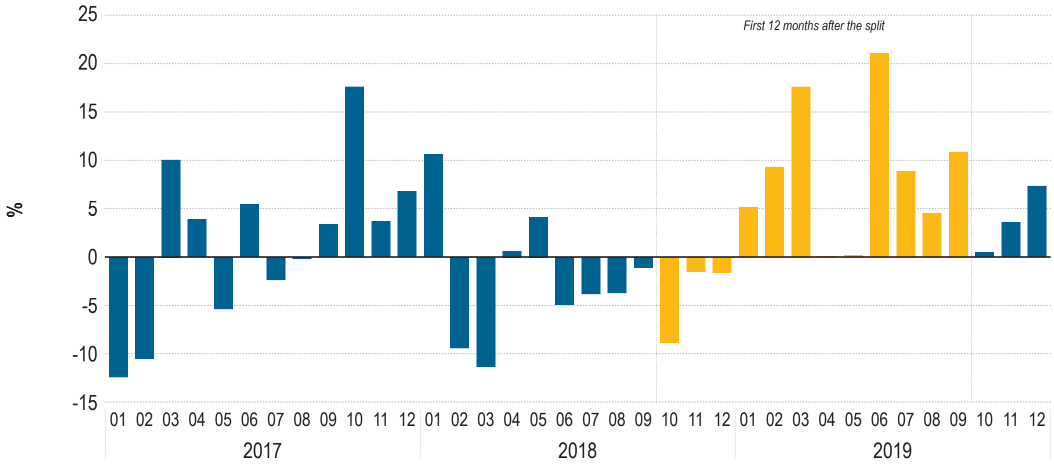
132 This Section attempts to shed light on the impacts of the bidding zone split on market liquidity by assessing first the evolution of short-term (mainly DA) markets' volumes and second the evolution of long-term markets' volumes and bid-ask spreads in the concerned geographical areas following the above-mentioned split.

133 Figure 22 shows the monthly relative change of volume compared to the same month in the previous year in the overall DA market in Austria, Germany and Luxembourg, taken together, since 2017. The figure shows an overall year-on-year increase in traded volumes in the period comprising the 12 months following the bidding zone split (+5.2% for the overall period).

134 During the same period, no similar increases in DA liquidity took place in Europe, which suggests that the increase in the German-Austrian area is mostly explained by the bidding zone split. Before the split, market participants with assets or trading activity in both markets were able to net their positions in a common bidding-zone. However, after the split, market participants need to close their positions in the market, independently for both bidding zones.

135 A similar increase in intraday markets' liquidity was observed following the bidding zone split (+7% year-on-year increase for the 12 months following the split), although this increase cannot be only attributed to the split itself, rather to a combination of factors including the overall increasing trend in intraday market liquidity in Europe.

Figure 22: Year-on-year monthly change in DA traded volumes at EPEX SPOT and EXAA for delivery in Austria, Germany and Luxembourg – 2017–2019 (%)

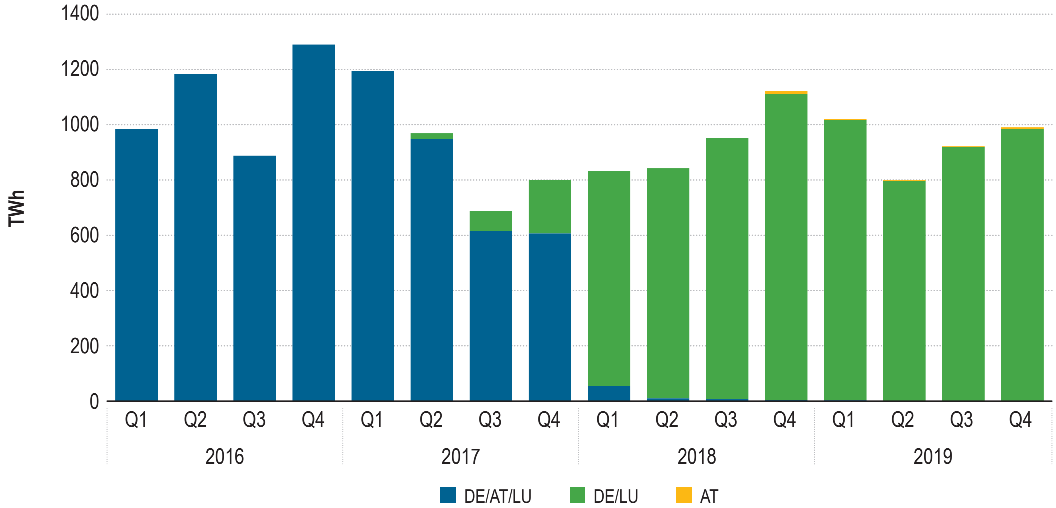


Source: ACER calculations based on aggregated REMIT data.

98 See footnote 57.

136 Figure 23 displays the evolution of quarterly forward trading volumes in the concerned geographical areas between 2016 and 2019. The figure shows a pronounced year-on-year decrease in traded volumes in 2017. While the decrease was partly mirroring the overall decreasing trend in the volumes traded in European forward markets in 2017, the uncertainty about the timeline and the effective implementation of the bidding zone split, until its confirmation in May 2017[99], possibly contributed to exacerbate the liquidity drop up to, and including, the third quarter of 2017.

Figure 23: Quarterly forward traded volumes in Germany/Luxembourg and Austria per bidding zone – 2016–2019 (TWh)



Source: EEX (futures and cleared OTC) and ACER calculations based on non-cleared Prospex data (for non-cleared OTC).

137 After the third quarter of 2017, the following developments were observed. First, a prolonged increase in market liquidity up to 2019, although the all-time high levels of 2016 were not reached. The increase coincided with the introduction of products for the new bidding zones of Germany/Luxembourg[100] and Austria, which progressively replaced the products traded for the formerly single bidding zone comprising the three MSs. Second, a progressive shift from OTC to power exchange-based trading, similar to the one observed in Europe (see Figure 17 in Section 4.1) was also recorded in these three MSs. Finally, while the forward market churn ratio remained high in Germany/Luxembourg following the split (around 8 in 2019), the ratio is still very low (0.24 in 2019) in Austria, despite the significant increase observed in 2019 (+25%) when compared to 2018 (0.19).

138 In this regard, the evolution of bid-ask spreads of typical products in each bidding zone provides further insight on the relative evolution of liquidity in the respective markets. Figure 24 below shows the evolution of bid-ask spreads of yearly contracts in the respective bidding zones, while France is added for comparative purposes. As opposed to Figure 18, which shows bid-ask spreads of OTC traded contracts, Figure 24 refers to products traded at the power exchange, as for the latter case information on the German/Luxembourgish and on the Austrian bidding zone products was separately available.

139 The following conclusions can be drawn from Figure 24. First, it shows a steady increase in bid-ask spreads in the yearly products traded for the formerly unified bidding zone as these products were phasing out. Second, it shows a year-on-year decrease (-16%) of bid-ask spreads in Germany in 2019 and early 2020 (base-load 2021 product, in the figure) consistently with an increasing activity at the power exchange (see paragraph 136). Third, it shows a significant decrease in the bid-ask spreads in Austria (to less than a half over the last two years) as the Austrian products started to become more widely used. Finally, the chart shows that the bid-ask spreads in

99 The official agreement between Austria and Germany was only enforced on 15 May 2017. For more information, please see the agreement's press declaration, available at: https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2017/15052017_DE_AU.html?nn=404422.

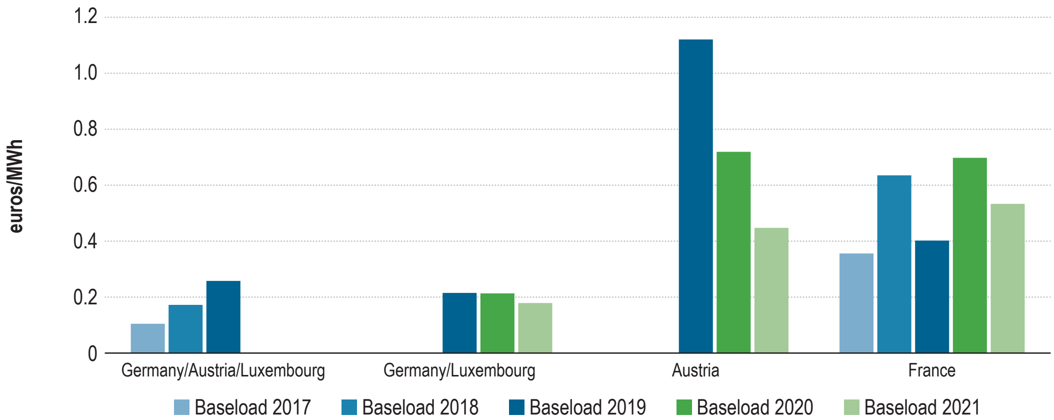
100 New products were launched by EEX as follows:
- 11/13 April 2017 – First communications to members that German futures would be prepared;
- 25 April 2017 – First German futures introduced (monthly/quarterly/yearly base-load/peak contracts);
- 26 June 2017 – First Austrian futures introduced (monthly/quarterly/yearly base-load/peak contracts) and range of German products complemented (daily/weekly futures and monthly/quarterly/yearly options); and
- 21 September 2017 - further German futures (weekend) introduced and Austrian future portfolio extended.

Austria became comparable to those observed in France (or even smaller for the base-load for delivery in 2021 product[101]).

140 The evolution of bid-ask spreads in Austria compared to the evolution of bid-ask spreads in Germany suggests that the size of the bidding zone is a relevant factor explaining forward markets liquidity. However, the fact that Austrian spreads have become comparable to the French also suggests that the size of the bidding zone is unlikely the only factor explaining forward markets liquidity[102].

141 All in all, it seems that following the bidding zone split, the opportunities for German market participants willing to use German forward products for hedging purposes have not significantly changed while Austrian market participants initially encountered more difficulties to use local (Austrian) products for hedging, due to the lower liquidity in the Austrian bidding zone. However, based on the evolution of bid-ask spreads, this difference has already decreased substantially over the past two years.

Figure 24: Average bid-ask spreads for yearly forward products traded in EEX with delivery in Germany, Austria, Luxembourg and France – 2017–2021 delivery (euros/MWh)



Source: EEX.
Note: Tick-size granularity bid-ask spreads were averaged out throughout the period from 18 to 9 months before delivery start.

142 Finally, local forward contracts should not be considered as the only hedging possibility for market participants. On the one hand, market participants located in a given bidding zone can combine one or more products of an adjacent bidding zone with transmission rights between the two bidding zones, the latter to hedge the risk of price differentials between the two market areas. On the other hand, market participants with hedging demands can use forward contracts in neighbouring markets (not necessarily adjacent ones) as proxies, if they consider that such contracts sufficiently meet their needs. For any bidding zone, a proxy could be a forward contract for another bidding zone or a combination of several forward contracts, e.g. for different bidding zones. The important issue would be whether a position in the proxy has sufficient correlation and thus provides sufficient hedging opportunities for the market participant. In order to identify potential proxies, a correlation analysis should be performed.

143 A possible correlation analysis is to compare the average local DA price with the average DA price in the zones considered relevant for hedging as a proxy[103]. For example, Table 3 shows the correlation of monthly average day-ahead prices across all possible combination of bidding zones within the CWE region in 2019, including the correlation between each bidding zone and an arithmetic average of CWE day-ahead prices.

101 For this analysis, the trading period considered for the base-load product for delivery in 2021 was between 1 July 2019 and 31 March 2020.

102 For a more detailed discussion on the relation between different indicators of forward markets liquidity and bidding zone size, please see Section 4.1 of the Electricity Wholesale volume of the 2017 MMR, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/MMR%202017%20-%20ELECTRICITY.pdf.

103 The analysis is in line with the recommendation included in a report commissioned by ACER on “Liquidity and transaction costs”. The report suggests several metrics to measure the impacts of a bidding zone change on liquidity, including the performance of a correlation analysis with a time resolution that should not be shorter than a month. For more information, please see page 18 of the report, available at: https://www.acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/Documents/200406%20DNV%20GL%20report_final.pdf.

Table 3: Monthly average DA price correlation matrix between CWE bidding zones – 2019

	Monthly average 2019 DA prices correlation matrix					
Bidding zone	AT	BE	DE/LU	FR	NL	CWE average price
AT	1.00	0.93	0.94	0.97	0.92	0.98
BE	0.93	1.00	0.87	0.98	0.96	0.98
DE/LU	0.94	0.87	1.00	0.91	0.85	0.93
FR	0.97	0.98	0.91	1.00	0.95	0.99
NL	0.92	0.96	0.85	0.95	1.00	0.97
CWE average price	0.98	0.98	0.93	0.99	0.97	1.00

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

Note: The correlation between the monthly average prices in zones A and B is defined as the ratio of their covariance and the product of their individual standard deviations.

144 Some observations can be derived from Table 3. First, the correlation of monthly average day-ahead prices tends to be high within the CWE[104]. Second, all market participants within CWE may consider using the highly liquid German market for hedging. With regard to Austrian market participants, they could consider using forward contracts of any of the bidding zones within the CWE region, including the highly liquid German market. Finally, the highest average correlation is observed between an arithmetic average CWE price and the individual bidding zone prices[105]. This means that if a regional price reference covering the whole CWE Region (e.g. a CWE arithmetic average DA price) was introduced as a financial product for hedging purposes, all market participants in any bidding zone of the region would have the possibility to share a highly correlated contract for hedging purposes. While, at the moment, the German forward market seems to be acting as a hub for the region, a regional reference price related to the entire CWE region could be an option to be considered in the future.

104 All correlations shown in Table 3 are above 0.9, with the main exceptions of the bidding zone pairs Belgium-Germany and Germany-The Netherlands, which can still be highly correlated based international standards. For example, based on international references, a correlation above 0.8 is considered as high in the report on “Methods for evaluation of the Nordic forward market for electricity” on page 36, available at: http://www.nordicenergyregulators.org/wp-content/uploads/2016/10/161208-Methods-for-evaluation-of-the-Nordic-forward-market-for-electricity.pdf.

105 Similar findings were presented in DNV’s study “Liquidity and transaction costs”. For more information, please see page 20 of the report, available at: https://www.acer.europa.eu/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/Documents/200406%20DNV%20GL%20report_final.pdf.

5 Efficient use of available cross-zonal capacity

145 This Chapter reports on the progress made regarding the efficient use of available cross-zonal capacities in the DA (Section 5.1), ID (Section 5.2) and balancing (Section 5.3) timeframes across Europe. Section 5.3 also reports on the latest developments of the initiatives for the exchange and sharing of balancing services, and provides an overview of the level of prices and of the lead time for procuring reserves in Europe.

5.1 Day-ahead markets

146 In recent years, significant progress has been made towards implementing the Electricity Target Model (ETM) for the DA market timeframe, which foresees a single DA coupling at European level that enables cross-zonal capacity to be used in the 'right economic direction' (from low- to high- price areas)[106] in case of a price differential across a given bidding-zone border[107]. The progress already made towards market integration, as well as the potential for further progress, is illustrated by two indicators.

147 First, Figure 25 shows the level of efficient use of electricity interconnectors in the DA market timeframe across all European borders. For the purpose of this analysis, efficient use is defined as the percentage of the available NTC used in the 'right economic direction' in the presence of a significant (>1 euro/MWh) price differential. The coupled borders (indicated by the blue bars in Figure 25), representing two thirds of the European borders (i.e. 25 European countries[108]), show 100% efficiency.

148 For the remaining borders, which are not coupled, the difference between 100% and the level of efficiency shown in Figure 25 indicates the potential for improvement. The finalisation of the DA market coupling on these borders in Europe will lift the level of efficient use of cross-zonal capacity in the DA timeframe, which for 2019 was measured at 88%[109], and consequently the overall economic efficiency of European electricity wholesale markets.

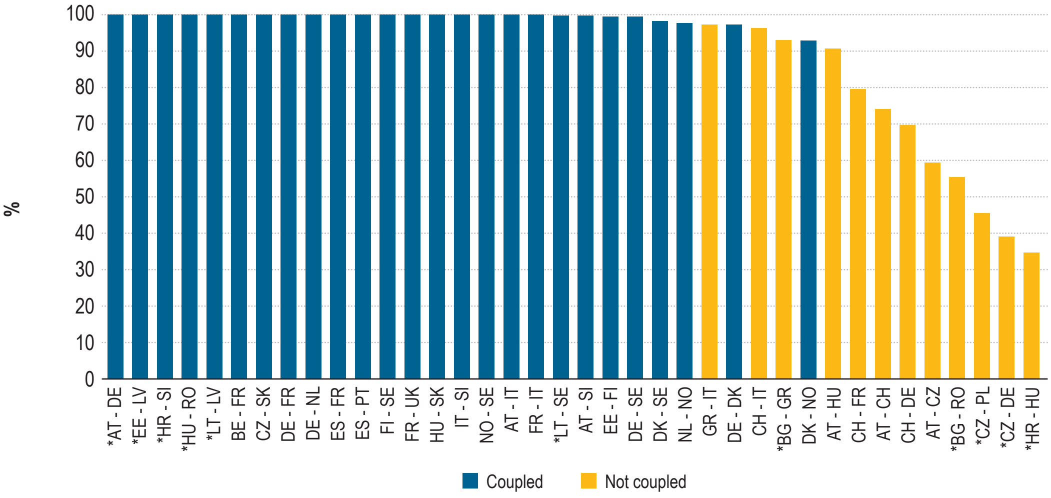
106 This definition of efficiency is a slight simplification of the welfare optimisation problem. In some circumstances, non-intuitive flows (from higher to lower price areas) may be beneficial if the welfare economic cost of a non-intuitive flow is smaller than the welfare economic benefit of the congestion relieved by such a non-intuitive flow. These situations are not analysed in this Section.

107 For more information, please see the methodological paper on 'Benefits from day-ahead and intraday market coupling', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Benefits%20from%20day-ahead%20and%20intraday%20market%20coupling.pdf.

108 By the end of 2019, DA market coupling had been implemented on 32 out of 42 EU borders (excluding the four borders with Switzerland). Please see footnote 110 for the countries included in the two differentiated market coupling initiatives that still coexist in Europe.

109 This value is not directly comparable with the level of efficiency reported in preceding MMRs, which was slightly higher. In previous MMR editions, some EU borders were not included in the analysis due to missing data. As most of the borders for which data are missing have not yet been coupled, the overall level of efficiency in the use of cross-zonal capacity for the whole EU is lower than the level reported in preceding MMRs.

Figure 25: Level of efficient use of cross-zonal capacity in the DA market timeframe, per border in Europe – 2019 (%)



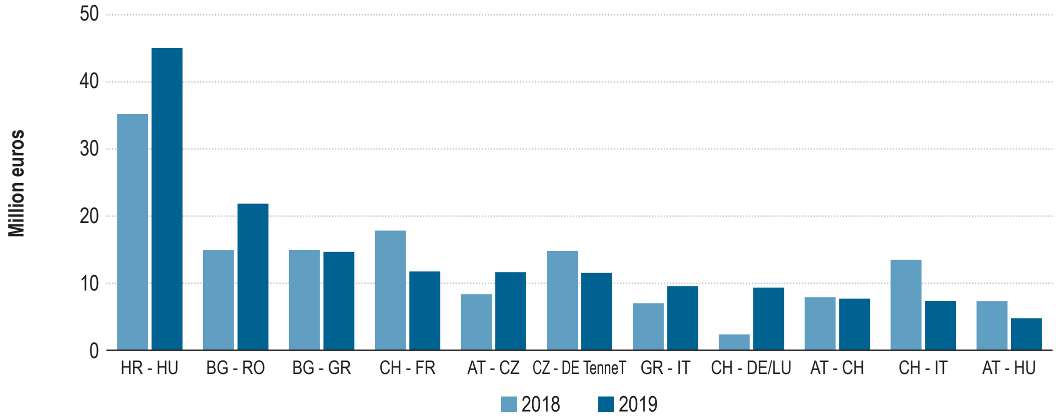
Source: ACER calculations based on ENTSO-E data.

Note: This figure contains data on all European bidding zone borders (except cross-zonal borders within countries and technical profiles), aggregated into country borders for convenience. The borders that were not included in previous MMRs are indicated with an asterisk (*). On some coupled-borders, the level of efficiency is reported to be below 100%. This may be either due to the existence of network losses factors (e.g. on some direct current (DC) interconnectors) which were not factored in the calculations underlying the figure, or due to occasional discrepancies between the reported DA NTC value and the actual offered capacity. For borders where specific data on DA schedules was not available, aggregated data (DA plus ID) on schedules was used. Finally, the level of efficiency on CWE borders, where NTC values are no longer used since the application of FBMC, is assumed to be 100%.

149 Second, Figure 26 shows that the overall estimated welfare gains to be obtained from extending DA market coupling to all EU borders, including the Swiss ones, amount to over 150 million euros per year. Among the non-coupled borders, the largest social welfare gains could still be obtained on the Croatian and Bulgarian borders[110]. Also, a relevant part of the above mentioned benefits will be delivered when the borders between Switzerland and the EU are coupled. However, this does not appear to be possible until the conditions envisaged in the CACM Regulation are met: the implementation of the main provisions of Union electricity market legislation in the Swiss national law and the conclusion of an intergovernmental agreement on electricity cooperation between the Union and Switzerland.

110 The remaining 10 non-coupled EU borders are: AT-CZ, AT-HU, BG-GR, BG-RO, CZ-DE, CZ-PL, DE-PL, GR-IT, PL-SK and HR-HU. The borders between the 4MMC and the MRC regions, i.e. AT-CZ, AT-HU, CZ-DE, CZ-PL, PL-SK and DE-PL are expected to be coupled initially through the NTC method (probably in 2020) before moving to FBMC. The HR-HU border is not included in this group and so far there is no roadmap for market coupling other than the Core FBMC. The coupling of the Greek and Italian markets is also expected in 2020 for both technical reasons and the ongoing reform of the Greek market towards the target model. The coupling of the Bulgarian-Greek-Romanian markets depends on the development of the integration of the whole Core region, and it could be expected to take place after the coupling of the 4MMC and MRC regions. A new project for the coupling of the Bulgarian-Croatian-Serbian markets was launched in February 2019 to implement trilateral market coupling within the MRC framework.

Figure 26: Estimated social welfare gains still to be obtained from further extending DA market coupling per border – 2018–2019 (million euros)



Source: ACER calculations based on ENTSO-E, NRAs and Vulcanus data.

Note: Only non-coupled borders are shown.

150 In conclusion, DA market coupling remains a crucial outstanding element in the integration of European electricity markets. The efficient use of interconnectors did not significantly increase in the last five years. The potential relevant welfare gains from extending implicit DA capacity allocation methods to all remaining European bidding zone borders that still applied explicit DA auctions at the end of 2019 highlight the urgency of such an extension, in particular in the Core region, which should follow the implementation deadline according to ACER's decision on the capacity calculation methodology for that region[111].

5.2 Intraday markets

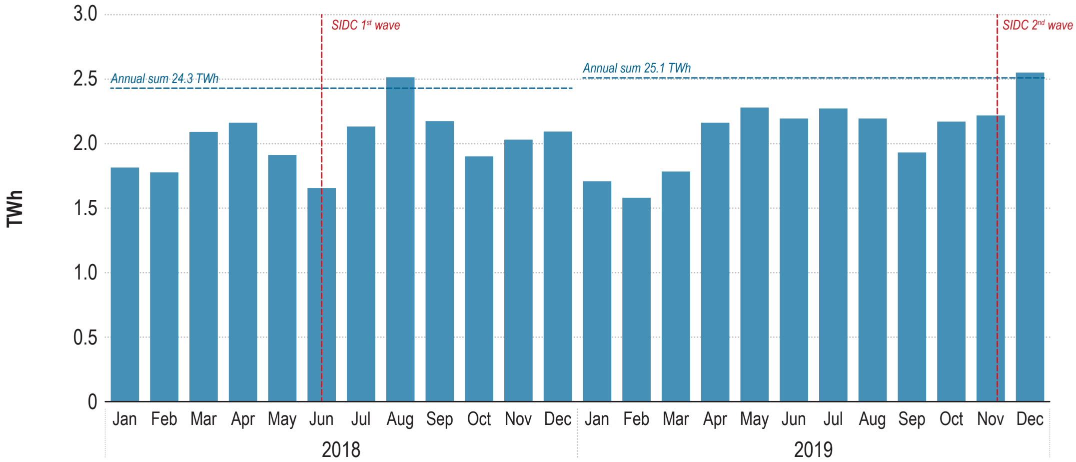
151 Similarly to previous editions of the MMR, this Section assesses the level of economic efficiency in the use of available cross-zonal capacity in the ID market timeframe[112] by analysing the evolution of cross-zonal intraday exchanges and the level of utilisation of cross-zonal capacity in the ID timeframe when it has an economic value (>1 euro/MWh).

152 Figure 27 shows that, in absolute terms, aggregated cross-zonal volume nominated in the ID market timeframe across the European network visibly increased after the go-live of the SIDC. This upward trend in nominations is consistent with the increase in ID-traded volumes observed in most MSs over the same period (see Section 4.3).

111 ACER Decision 02/2019 of 21 February 2019 on the Core CCR TSOs' proposals for the regional design of the day-ahead and intraday common capacity calculation methodologies, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2002-2019%20on%20CORE%20CCM.pdf.

112 The level of efficiency is defined as the absolute sum of net nominations and the level of utilisation of cross-zonal capacity in the ID timeframe when it has an economic value (>1 euro/MWh). See footnote 107.

Figure 27: Absolute sum of net ID nominations for a selection of EU borders – 2018–2019 (TWh)



Source: ACER calculations based on Vulcanus data.

Note: This figure contains data for all European bidding zones with ID markets. No comparison should be made with the analysis performed in previous MMRs, where the list of borders analysed was shorter due to unavailability of the data.

153 Despite the increasing trend of ID-traded volumes and cross-zonal nominations in the ID market timeframe, the efficiency[113] of the utilisation of ID cross-zonal capacity remains at 59%, significantly lower than the DA market timeframe (an average of 88% in 2019, see Figure 25) but about 9 percentage points higher than in 2018. This increase can be largely attributed to the Single Intraday Coupling, which was operational through all 2019, and to a lesser extent to the launch of the second wave in late 2019, which included 7 additional intraday markets (see paragraph 128 in Section 4.3 for more information on the 2nd wave countries).

154 Second, the analysis of individual borders confirms that cross-zonal capacity was allocated more efficiently by using implicit allocation methods (69% efficiency) rather than explicit or other allocation methods (49% efficiency).

155 Overall, this analysis suggests that a part of the potential benefits from the use of existing infrastructure in the ID market timeframe remains untapped across Europe. The additional welfare benefits from a more efficient use of ID cross-zonal capacity across Europe are estimated at over 50 million euros annually[114]. However, the introduction of the second wave of SIDC at the end of 2019, the anticipation of a third wave foreseen in Q1/2021[115] and, finally, the implementation of pan-European ID auctions as envisaged in ACER Decision 01/2019[116], are expected to further increase the economic efficiency in the use of cross-zonal capacity in the ID timeframe.

113 Similar to the study done in previous MMR versions (see 2017 MMR, Figure 36), the intraday efficiency is defined as the percentage of hours where the intraday capacity is "sufficiently" used in the economic direction (based on threshold values). For more details, see the methodological paper in footnote 91. Finally, the analysis was done for a selection of borders, similar to the study done in previous MMR versions (see 2017 MMR, Figure 36).

114 For more information on how to estimate welfare benefits from increased efficiency in the use of ID cross-zonal capacity see the methodological paper in footnote 107. The actual welfare benefits from ID cross-zonal trade may be considerably higher as both intraday markets liquidity and the intraday capacity offered by TSOs via capacity recalculation is expected to increase in the coming years.

115 The third wave is expected to include Italy and Greece. More information on the SIDC integration is available at: https://www.entsoe.eu/network_codes/cacm/implementation/sidc/, and http://www.nemo-committee.eu/sidc.

116 ACER Decision 01/2019 of 24 January 2019 establishing a single methodology for pricing intraday cross-zonal capacity, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2001-2019%20on%20intraday%20cross-zonal%20capacity%20pricing%20methodology.pdf.

5.3 Balancing markets

156 This Section provides an update on the prices of balancing services (energy and capacity) (Subsection 5.3.1), assesses the situation of the lead time for the procurement of balancing capacity (Subsection 5.3.2) and gives an overview of the exchanges of these services across EU borders (Subsection 5.3.3).

5.3.1 Balancing (capacity and energy)

157 The EB Regulation, which entered into force in 2017[117], lays down detailed rules on electricity balancing, including establishing common principles for the procurement, activation and exchanges of balancing energy, the procurement and exchange of balancing capacity and sharing of reserves, including the allocation of cross-zonal capacity. It strives to implement an integrated balancing market, which will allow TSOs to procure, exchange and use balancing energy and capacity in an economically efficient and market-based manner.

158 To accelerate the integration of balancing markets, several initiatives have been launched in Europe, including the frequency containment reserves (FCR) cooperation project[118] for procuring and exchanging balancing capacity for FCRs; the regional International Grid Control Cooperation (IGCC) project[119] operating the imbalance netting process; the Common Baltic Balancing Market[120] platform for manually-activated frequency restoration reserves (mFRRs) exchanges; the Nordic Balancing Model (NBM)[121], a Nordic programme aimed at implementing a common balancing market, and the Trans European Replacement Reserves Exchange (TERRE) platform for exchanging balancing energy from replacement reserves (RRs). These projects have proven useful to stimulate the exchanges of balancing services in Europe. They will need to adapt to the EB Guideline requirements, and to become part of the reference projects (see Subsection 5.3.3) to allow for a greater efficiency and better synergies across Europe.

159 Nevertheless, while waiting for major European projects and platforms initiated by the EB Regulation to be introduced more widely[122], large disparities in balancing energy and balancing capacity prices persisted in 2019 (see Figure 28 and Figure 29 for automatically-activated frequency restoration reserves (aFRRs)).

160 Compared to previous years, an improvement in price convergence was observed between Austria and Germany. While in 2017 the prices for downward energy activated from aFRRs in these two countries were negative and significantly different (-82 euros/MWh for Austria and -15 euros/MWh for Germany), they became positive and on average very similar in 2019 (1 and 3 euros/MWh, respectively).This is partly due to the implementation of a balancing cooperation project for the exchange of balancing energy from aFRRs between these two countries in 2016, which has gradually increased competition.

117 See footnote 24.

118 FCR currently involves ten TSOs in seven countries: the TSOs in Austria (APG), Belgium (Elia), Switzerland (Swissgrid), Germany (50Hertz, Amprion, TenneT DE, TransnetBW), Western Denmark (Energinet), France (RTE) and the Netherlands (TenneT NL). For more information, please see: https://www.entsoe.eu/network_codes/eb/fcr/.

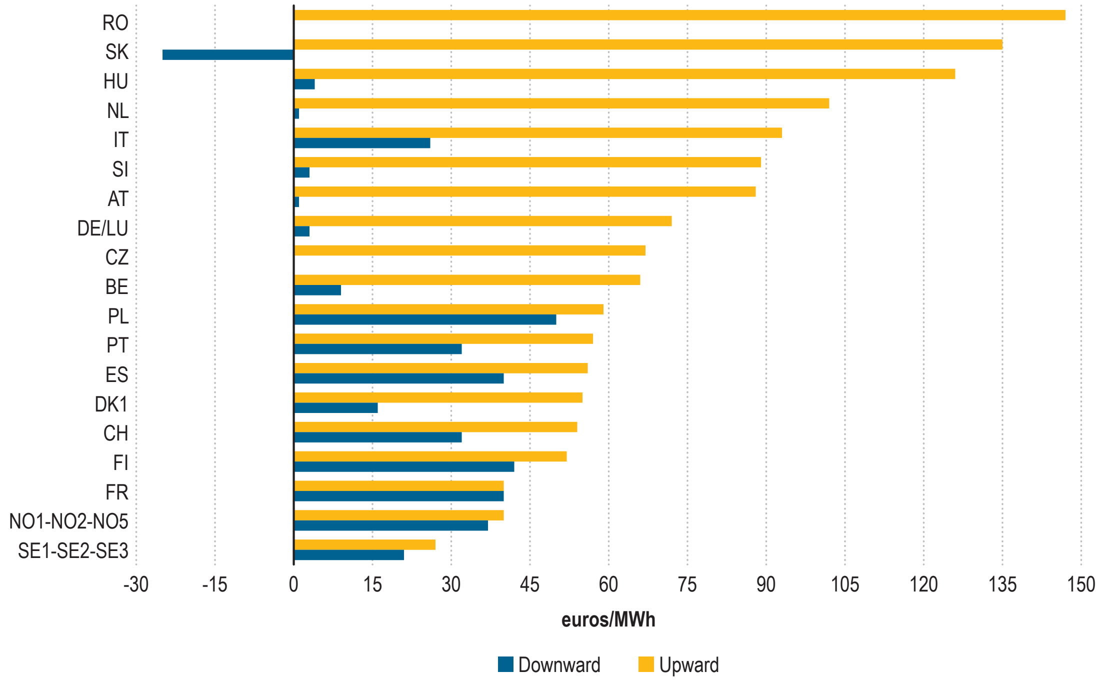
119 IGCC is a regional project for the imbalance netting process. Currently, it involves 14 TSOs in 11 countries: the TSOs in Austria (APG), Belgium (Elia), Switzerland (Swissgrid), the Czech Republic (CEPS), Germany (50Hertz, Amprion, TenneT DE, TransnetBW), Denmark (Energinet.dk), France (RTE), the Netherlands (TenneT NL), Slovenia (Eles), Croatia (HOPS) and Italy (TERNA). For more information, please see: https://www.entsoe.eu/network_codes/eb/imbalance-netting/.

120 The Common Baltic Balancing Market started operating on 1 January 2018. It allows the Baltic TSOs (Elering, AST and Litgrid) to exchange standardized mFRR products through a common merit order list. For more information, please see: https://dashboard-baltic.electricity-balancing.eu/.

121 The TSOs in Denmark (Energinet), in Finland (Fingrid), in Norway (Statnett) and in Sweden (Svenska kraftnätt) take part in this project. For more information, please see: http://nordicbalancingmodel.net/.

122 See Subsection 5.3.3.

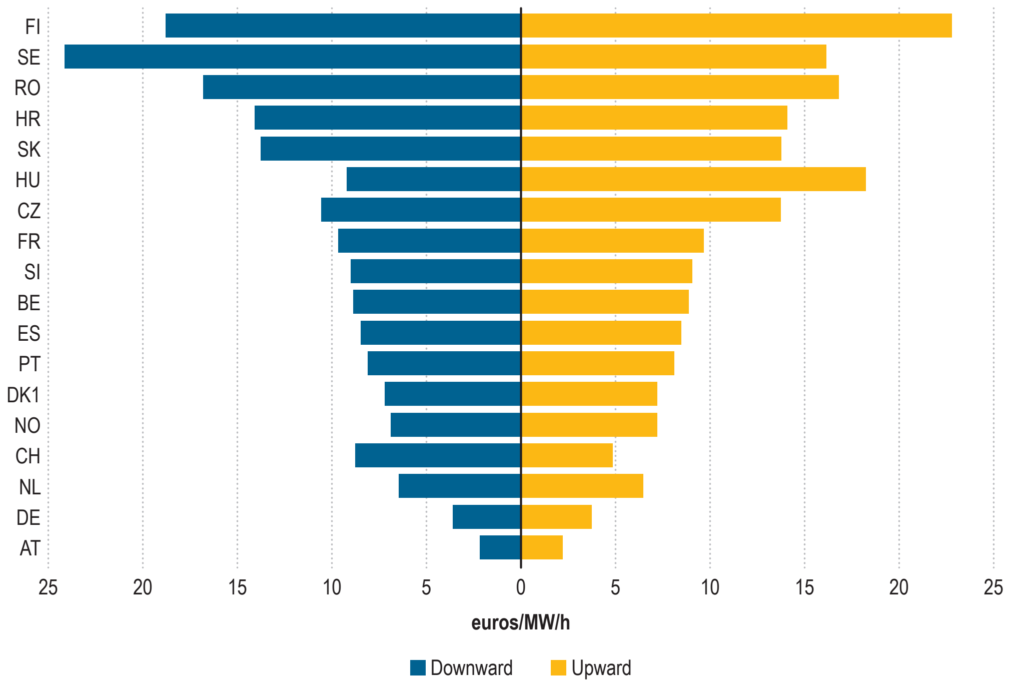
Figure 28: Weighted average prices of balancing energy activated from aFRRs (upward and downward activations) in a selection of EU markets – 2019 (euros/MWh)



Source: ACER calculations based on ENTSO-E data.

Note: The values shown in the figure refer to the prices of activated balancing energy in a given market area, irrespective of whether the activations aim to cover the needs for balancing in the same or in neighbouring market areas.

Figure 29: Average prices of balancing capacity (upward and downward capacity from aFRRs) in selected EU markets – 2019 (euros/MW/h)



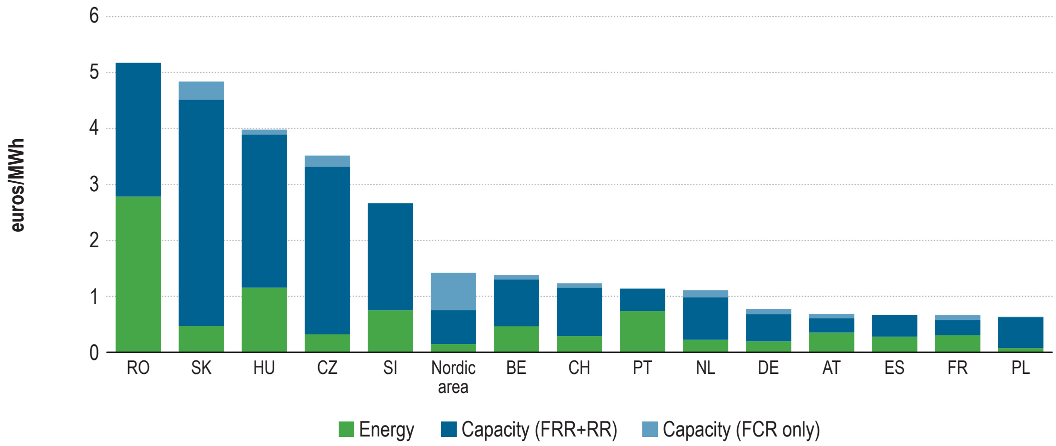
Source: ACER calculations (2020) based on NRAs data.

161 Figure 30 displays the overall costs of balancing[123] for a selection of countries for which sufficient data was available. Compared to 2017[124], a decrease in balancing capacity procurement costs was observed in most countries, which is consistent with the drop of balancing capacity prices over the last two years. There were only a few increases in balancing capacity procurement costs observed: for FCRs in the Nordic area, and for frequency restoration reserves (FRRs) in Germany (due to higher prices) and the Netherlands (due to an increased volume procured). The costs related to the activation of balancing energy remained essentially unchanged or slightly below 2017 levels, which is consistent with the evolution of balancing energy prices.

162 The reasons for the drop in capacity costs are manifold. It can partly be attributed to the extension or go-live of European projects (detailed in Subsection 5.3.3), and to certain changes in national markets design. In particular, moving from symmetric capacity procurement to bidirectional procurement (as in Slovenia and Switzerland for aFRRs), and moving towards procuring balancing capacity closer-to-real-time (for example, D-2 auctions for FCR cooperation, see Subsection 5.3.2) allows a wider group of market participants (including RES and DSR) to become balancing service providers (BSPs) and increase competition. Larger hydro reservoirs for some countries in 2019 than in 2017, less capacity contracted, and improvement in the TSO's algorithms also contributed to the decline in capacity costs.

163 Overall, the conclusions drawn from equivalent figures in preceding MMRs are still valid: in most MSs, the largest share of balancing costs continued to be the procurement costs of balancing capacity, which emphasises the importance of optimising balancing capacity procurement costs.

Figure 30: Overall costs of balancing (capacity and energy) over national electricity demand in selected European markets – 2019 (euros/MWh)



Source: ACER calculations based on NRAs data.

Note: The overall costs of balancing are calculated as the procurement costs of balancing capacity and the costs of activating balancing energy (based on activated energy volumes and the unit cost of activating balancing energy from the applicable type of reserve). For the purposes of this calculation, the unit cost of activating balancing energy is defined as the difference between the balancing energy price of the relevant product and the DA market price. For Switzerland, the balancing energy costs are based only on the activation of balancing energy in Switzerland as information on the financial settlement of cross-border activations or imbalance netting was not available.

123 See how balancing costs are defined for the purpose of this analysis in the note below Figure 30.

124 The latest assessment on balancing costs was made by ACER in the Electricity Wholesale Markets Volume of the 2017 MMR. See footnote 102.

5.3.2 Lead time for the procurement of balancing capacity

164 The recast Electricity Regulation[125] reasserts[126] the principle established in the EB Regulation, that balancing capacity procurement should be performed on a short-term basis[127]. This principle aims to maximise the participation of flexible resources in short-term energy markets with a view to improve liquidity and competition. In particular, the day-ahead procurement of capacity advocated in the regulation[128] allows for an efficient arbitrage between day-ahead and balancing capacity markets. The main benefit of this requirement is a more sound formation of close-to-real-time prices which will better reflect the instantaneous needs of the system.

165 Following the implementation of the above mentioned provisions, the share of reserve capacity contracted as balancing capacity in day-ahead or intraday timeframes is expected to increase. Figure 31 and Figure 32 show that the lead time for procuring balancing capacity is currently uneven, depending on the type of reserve, and on the country. More than 60% of the capacity from RRs and aFRRs is contracted on a day-ahead basis, whereas more than 60% of the capacity from mFRRs is contracted on a monthly or yearly basis. The procurement of FCR is somewhere in the middle: a significant percentage (27%) is contracted on a weekly basis. This is partly due to the FCR cooperation project[129], which was contracted on a weekly basis: as of 1 July 2019, the reserve within the scope of the FCR cooperation project is auctioned two days before delivery for working days, while daily auctions are planned from 1 July 2020. In particular, the Belgian TSO announced that it would start procuring its entire FCR obligations via the FCR Cooperation project starting from this date[130]. Since the introduction of the D-2[131] auction on 1 July 2019, the Netherlands stopped holding its national auction[132], and procures its FCR volumes exclusively via the common auction.

166 Figure 32 shows that Poland, Portugal and Spain are already in line with the recast Electricity Regulation's requirements[133]. In Portugal, a small amount of reserves is procured even closer to real time than required by the recast Electricity Regulation, during the intraday timeframe. Austria, Germany, Denmark and Sweden have most of their reserves procured on a daily basis. In other jurisdictions (Belgium, Croatia, the Czech Republic, Great Britain, Hungary, Latvia, Lithuania, the Netherlands, Slovenia, Slovakia, Romania, and Switzerland), less than 10% of reserves are procured on a day-ahead basis, and significant efforts are needed for them to become aligned with the requirements of the recast Electricity Regulation.

125 See footnote 51.

126 Article 6(9) of the recast Electricity Regulation: "Contracts for balancing capacity shall not be concluded more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day".

127 Article 32(2) of EB Guideline: "The procurement process shall be performed on a short-term basis to the extent possible and where economically efficient".

128 Articles 6(9) to 6(11) of the recast Electricity Regulation. A derogation can be granted, but must be limited in time, and minimum quotas of balancing capacity contracted on at least a day-ahead basis have to be reached in any case.

129 See Subsection 5.3.1 and footnote 118.

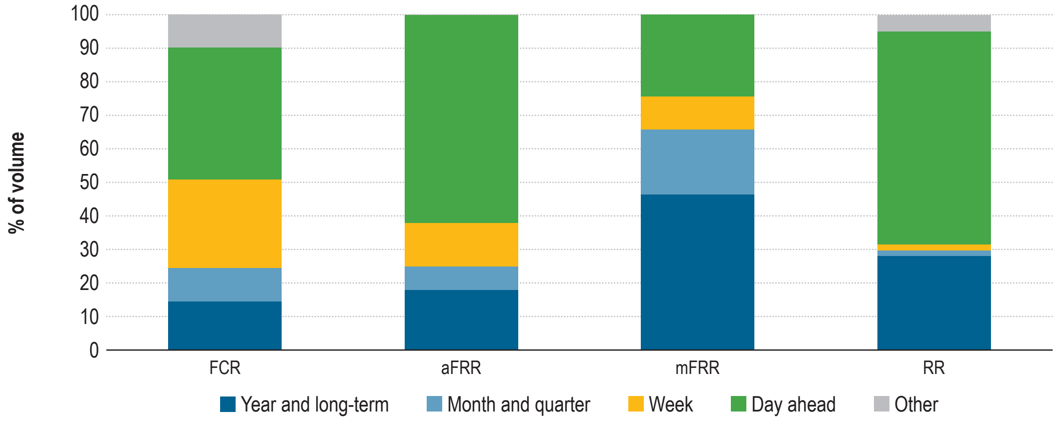
130 For additional information, please see ENTSO-E's announcement from 2 December 2019, available at: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Network%20codes%20documents/NC%20EB/191202_FCR_press_release_FCR_values_2020___BE_full_FCR_procurement.pdf.

131 Two days ahead of delivery.

132 See press release at: https://www.regelleistung.net/ext/static/prlnl?lang=en.

133 See footnote 126.

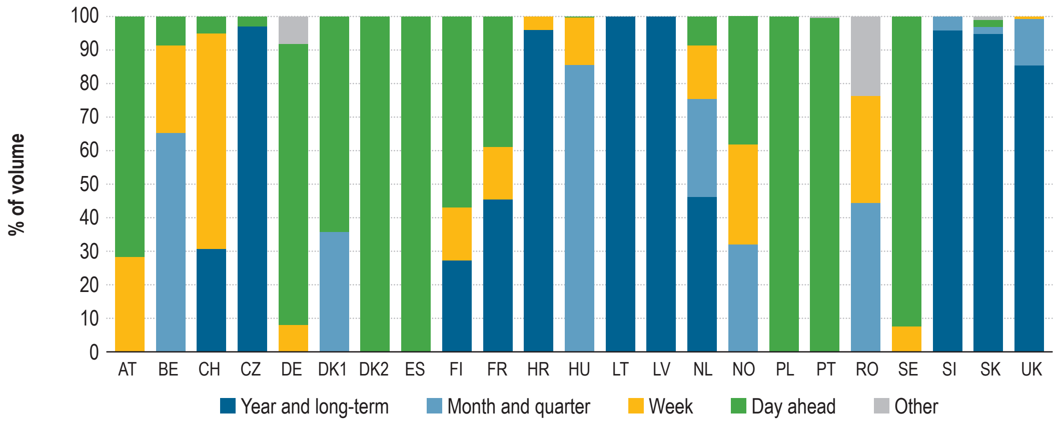
Figure 31: Repartition of the procurement lead time of each type of reserve – 2019 (% of volume)



Source: ACER calculations based on NRAs data.

Note: This figure is based on the countries mentioned in Figure 32. The category 'other' is for non-specified lead times, for D-2 for Germany and for intraday for Portugal.

Figure 32: Repartition of procurement lead time of each country, for all types of reserve (FCR, aFRR, mFRR, RR) – 2019 (% of volume)



Source: ACER calculations based on NRAs data.

5.3.3 Cross-zonal exchange of balancing services

167 Figure 33 and Figure 34 show, respectively, the share of activated balancing energy and balancing capacity (for FCRs) procured cross-border compared to the system's needs. Additionally, Figure 35 shows the application of imbalance netting as a percentage of the total needs for balancing energy.

Figure 33: EU balancing energy activated cross-border as a percentage of the amount of total balancing energy activated to meet national needs – 2019 (%)

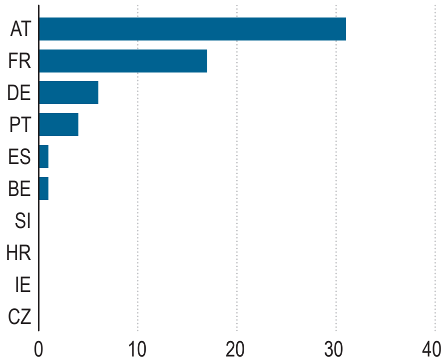
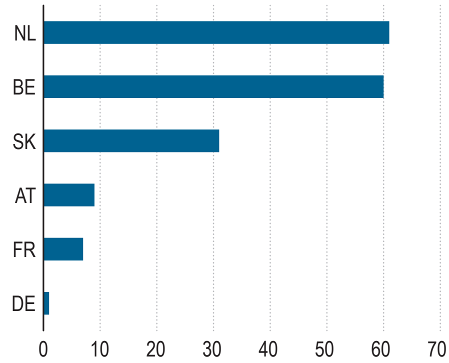


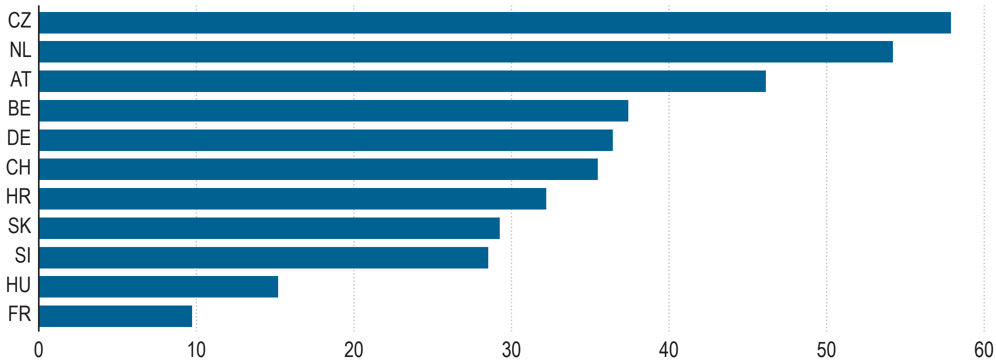
Figure 34: EU balancing capacity contracted cross-border as a percentage of the system requirements of reserve capacity (upward FCRs) – 2019 (%)



Source: ACER calculations based on NRAs data.

Note: These figures include only the countries that reported some level of cross-zonal exchange. The Baltic countries are part of a cooperation project for the exchange of balancing services, and activate balancing energy to balance the system as a whole. Consequently, imported balancing energy can only be estimated for the Baltic countries put together. The percentage of cross-border energy exchanges for Baltic countries is 44%, but is not strictly comparable to other countries. The actual exchange of balancing energy across borders within the Nordic region is not included in Figure 35, because the Nordic electricity systems are integrated and balanced as a single load frequency control (LFC) area. Therefore, the cross-zonal exchange of balancing energy cannot be disentangled from imbalance netting across borders.

Figure 35: Imbalance netting as a percentage of the total need for balancing energy (explicitly activated or avoided by means of netting) from all types of reserves in national balancing markets – 2019 (%)



Source: ACER calculations based on NRAs data.

Note: This figure includes only the countries that reported some level of cross-zonal exchange. The Nordic electricity systems are integrated and balanced as a single LFC area. The percentage of total need of balancing energy (imbalance netting and exchanged balancing energy, which cannot be disentangled) procured abroad for Nordic countries is 88%, but is not strictly comparable to the other countries.

168 In 2019, the level of exchange of balancing energy (Figure 33) remained similar to the levels in preceding years. The Baltic countries, which have shared a common Baltic balancing market for aFRR energy[134] since 2018, are an exception. Together, they covered 44% of their balancing needs with imports from other countries. The level of exchange of balancing capacity (Figure 34) has significantly increased for the Netherlands and Belgium, both members of the FCR cooperation project[135].

134 See footnote 120.

135 See footnote 118.

169 Compared to previous years, the level of exchange of balancing services in 2019 displayed in the figures above remains essentially unchanged. The main exceptions are the decrease in the amount of imbalance netting for Germany (-24% compared to 2018) and an increase in the level of imbalance netting for the Czech Republic, Croatia and Slovenia. The latter two experienced a rise of 7% each, probably as they both joined the IGCC[136] in early 2019.

170 As mentioned in Subsection 5.3.2, further improvement in cross-zonal exchanges for balancing services is expected in the coming years, with the launch of several initiatives stemming from the implementation of the EB Regulation. The status of the most relevant projects related to these initiatives is outlined below.

171 First, the FCR cooperation project has expanded geographically (see footnote 118) in recent years, and is expected to further expand in the near future. The project relies on a TSO-TSO-model[137] where the FCR is procured through a common merit order list where all TSOs pool the offers they receive from BSPs within their respective areas of responsibility. As mentioned, the procurement of the capacity involved in the project has been made two days before delivery since mid- 2019, and daily auctions are planned from 1 July 2020.

172 Second, the imbalance netting cooperation projects have been merging into a single project. In particular, the IGCC project extended its geographical scope to Slovenia and Croatia in 2019, and to Italy in early 2020. Bulgaria, Greece, Hungary, Portugal, Romania, Slovakia and Spain are also planning to join at different times. IGCC is now the European reference project for imbalance netting[138], and is expected to incorporate the geographical scope of the e-GCC[139] and imbalance netting cooperation (INC)[140] projects in the near future.

173 Third, the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)[141] became the reference project for establishing a platform for exchanging balancing energy from aFRR, in compliance with the EB Regulation. Previous aFRR cooperation projects in participating countries are part of PICASSO and considered to be interim steps on the way to target design; the existing aFRR cooperation project between Austria and Germany[142] is such an example. The first launch of the platform is planned for mid-2021[143]. Another example is the Nordic Balancing Market (see footnote 121). Between 2020 and 2023, the TSOs will gradually implement the changes in operational processes (in particular the single imbalance price model and the 15-minute imbalance settlement period), with a view to being merged first with the Manually Activated Reserves Initiative (MARI) and later with PICASSO.

136 See footnote 119.

137 'TSO-TSO model' is a model for the exchange of balancing services where the balancing service provider provides balancing services to its connecting TSO, which then provides these balancing services to the requesting TSO.

138 ACER Decision 13/2020 of 24 June 2020 on the implementation framework for the European platform for the imbalance netting process sets a twelve months deadline, after approval of this decision, for all TSOs to use the imbalance netting platform in order to operate the imbalance netting process for intended exchange of balancing energy. The decision is available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2013-2020%20on%20Implementation%20framework%20for%20imbalance%20netting.pdf.

139 The e-GCC is a project operating the imbalance netting process which involves ČEPS (Czech Republic), MAVIR (Hungary) and SEPS (Slovakia).

140 The INC was a project operating the imbalance netting process which involved APG (Austria), ELES (Slovenia) and HOPS (Croatia).

141 PICASSO originated as a regional project initiated by 8 TSOs in 5 countries, including APG, Tennet NL, Elia, RTE, 50Hertz, Amprion, Tennet DE and TransnetBW. Since its inception, the following TSOs have joined the project: ČEPS, Energinet, Fingrid, MAVIR, Statnett, ELES, Red Eléctrica de España, Svenska Kraftnät, HOPS, Fingrid, Terna, PSE, REN, Transelectrica and SEPS.
The following TSOs are participating in the PICASSO project as observers: the Bulgarian TSO ESO, the Greek TSO IPTO/ADMIE and the Swiss TSO Swissgrid. ENTSO-E participates in PICASSO in the role of an observer. All TSOs obliged to establish the aFRR-Platform, pursuant to the EB GL, are participating in the PICASSO project.

142 The aFRR-cooperation project involving the German and Austrian TSOs went live on 14 July 2016. This project allows the activation of the most efficient aFRRs based on a common merit order list and a TSO-TSO model. As a result, the costs of activating aFRRs can be reduced.

143 The accession roadmap of PICASSO is published on ENTSO-E's website, available at: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Network%20codes%20documents/Implementation/picasso/200424-EB_Reg_aFRRIF_PICASSO_Accession_roadmap.pdf.

174 Fourth, the launch of the platform for exchanging balancing energy from mFRRs is planned for 2022[144]. The platform is part of MARI, which was launched in April 2017 with the signing of a memorandum of understanding by 19 European TSOs. Since late 2019, the Austrian and German TSOs have operated 'GAMMA', a shared platform for the joint activation and netting of mFRRs.

175 In early 2020, ACER published two decisions on the implementation framework for a European platform for the exchange of balancing energy from aFRRs and mFRRs[145]. These decisions set the deadlines for the implementation of these platforms, and confirm PICASSO and MARI as reference projects for the implementation. Since the beginning of 2020, ACER also took several decisions on key aspects of the implementation of the exchanges of balancing services[146].

176 Last, the Trans European Replacement Reserves Exchange (TERRE) platform for exchanging balancing energy from RRs, was implemented in early 2020 with the effective incorporation of the Czech TSO. Other TSOs participating in the project (France, Italy, Great Britain, Poland, Portugal, France, Spain and Switzerland) are expected to join at different points in time between 2020 and 2022.

177 In addition, the actual volumes of imbalance netting and exchanged balancing energy can be compared to the potential of these two services, i.e. the maximum amount of imbalance netting and balancing energy volumes that could be exchanged subject to sufficient available cross-zonal capacity. Based on the methodology used in last year's MMR[147], the actual application of imbalance netting and exchange of balancing energy is estimated at approximately 23% of their potential in 2019 for a selection of 13 borders where sufficient information was available. It is comparable to the previous year, and is still relatively low when compared to the level of efficiency recorded in the preceding DA (88%) and ID (59%) timeframes in 2019. This is mainly due to the fact that the exchange of balancing energy (except imbalance netting) is still inexistent or residual on most European borders. The potential benefits from imbalance netting and exchange of balancing energy calculated for the whole of Europe, would be as high as 1.3 billion euros annually[148].

144 The accession roadmap of MARI is published on ENTSO-E's website, available at: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Network%20codes%20documents/Implementation/MARI/200424-EB_Reg_mFRRIF_MARI_Accession_roadmap.pdf.

145 ACER Decision 02/2020 of 24 January 2020 on the implementation framework for aFRR platform, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2002-2020%20on%20the%20Implementation%20framework%20for%20aFRR%20Platform.pdf and ACER Decision 03/2020 of 24 January 2020 on the implementation framework for mFRR platform, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2003-2020%20on%20the%20Implementation%20framework%20for%20mFRR%20Platform.pdf.

146 All ACER's decisions are available at: https://www.acer.europa.eu/m/official_documents/Pages/individual_decision.aspx.

147 For more information, please see the methodological paper on 'Benefits from balancing markets integration', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents/ACER%20Methodological%20paper%20-%20Benefits%20from%20balancing%20markets%20integration.pdf.

148 For additional information, please see the methodological paper mentioned in footnote 147 of this report and paragraph 582 of the Electricity Wholesale Markets Volume of the 2014 MMR, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

6 Capacity mechanisms and generation adequacy

178 The recast Electricity Regulation sets the framework for assessing mid-term[149] resource adequacy and provides general principles and design rules for CMs. Article 23 of the recast Electricity Regulation establishes the European resource adequacy assessment (ERAA) setting inter alia the high level characteristics of this assessment. Notably, national resource adequacy assessments (NRAA) shall also be based on the same methodology in many aspects. The application of a CM by a MS shall be justified on the basis of the results of resource adequacy concerns identified in the ERAA and/or NRAA. On 25/09/2020 ACER approved the methodology for the ERAA (ERAA methodology) proposed by ENTSO-E introducing significant amendments establishing a common European framework for the resource adequacy assessment[150].

179 According to Article 15 of the recast ACER Regulation[151], ACER shall monitor the performance of MSs in the area of security of supply of electricity based on the results of the ERAA and taking into account the evaluation of electricity crisis as per Article 17 of the Risk Preparedness Regulation (RPR)[152].

180 This Chapter starts by outlining the current status of CMs in Europe and provides an overview of the costs incurred or expected for financing them together with a breakdown of the technologies that are remunerated through the CMs (Section 6.1 and Section 6.2, respectively). It then briefly discusses updates concerning the way interconnections are taken into account in MSs' national adequacy assessments and provides a preliminary analysis of the necessity of CMs on the basis of perceived adequacy concerns resulting from ENTSO-E's 2019 Mid-term Adequacy Forecast (2019 MAF)[153] (Section 6.3).

6.1 Status of capacity mechanisms

181 Figure 36 presents the status of CMs in Europe as of the end of 2019[154]. The key changes compared to last year are as follows: first, the re-approval by the European Commission of the CM in GB in October 2019, following its annulment by the General Court of the European Union in November 2018 and a new in-depth investigation carried out by the European Commission; second, in Germany, the implementation of the first procurement process for Strategic Reserves (SR) in December 2019[155], third, in Italy, the first two auctions for reliability options in November 2019[156] and, finally, in Greece, the suspension of the transitory flexibility auction approved in 2018, since March 2019, and the proposal for a new CM, which is still under development.

149 The framework for seasonal and short term adequacy assessments is defined in the Regulation 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0941&from=EN.

150 See footnote 19.

151 See footnote 33.

152 Regulation (EU) 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC, available at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0941&from=EN.

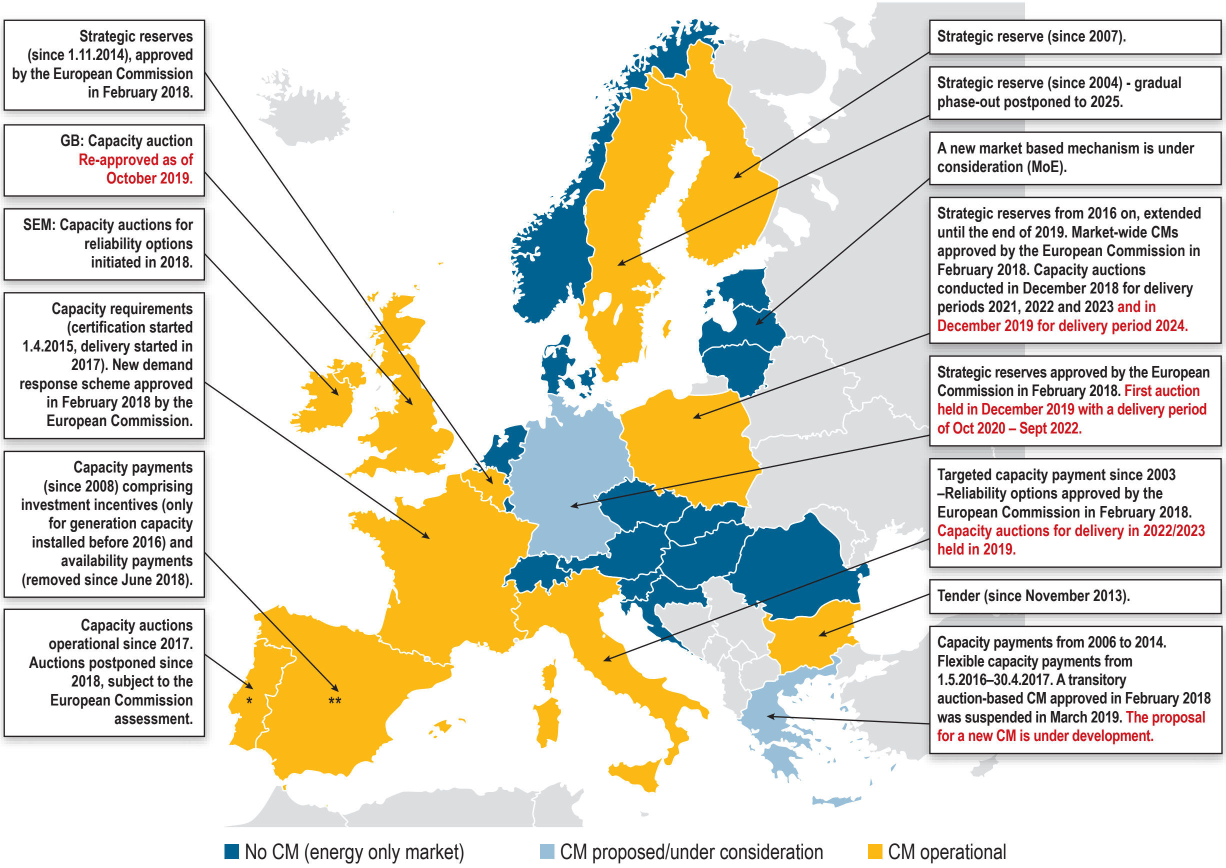
153 For additional information, please see: https://www.entsoe.eu/outlooks/midterm/.

154 As of this year's edition, the costs related to network and system reserve mechanisms will not be reported in the capacity mechanisms Section, in line with the definition of capacity mechanisms provided in Article 2(22) of the recast Electricity Regulation, and all related costs will be reported in the Section of remedial actions (Section 3.3). Such mechanisms apply at least in Austria, Germany, Latvia and Lithuania.

155 More information can be found in: https://www.netztransparenz.de/EnWG/Kapazitaetsreserve (in German).

156 More information can be found in: https://www.terna.it/it/sistema-elettrico/mercato-capacita (in Italian).

Figure 36: CMs in Europe – 2019



Source: NRAs.

Note: Changes with respect to 2018 are outlined in red. While in Portugal and Spain the CMs are marked as operational, the following caveats apply: in Portugal, the CM in place has been postponed since 2018; in Spain**, the CM used to comprise "investment incentives" and "availability payments"; however, such availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016.*

182 Figure 37 provides an update on the costs incurred or expected to be incurred at MS level in order to finance CMs. In 2019, the overall cost of CMs across the EU increased by 73% compared to 2018, reaching 3.9 billion euros. Based on the results of CM auctions held in several countries for delivery in 2020 and beyond, the total amount to finance CMs will likely continue to grow. In particular, the Italian auctions resulted in a total anticipated cost of 2.8 billion euros for 2022 and 2023[157] while the anticipated cost from the Polish auctions will reach 7.7 billion for the 2021–2024 period[158]. In Germany, the resulting costs of the SR for 2020 will add approximately 20 million euros[159]. At the same time, a few other MSs, such as Lithuania and Greece are considering establishing CMs in the near future.

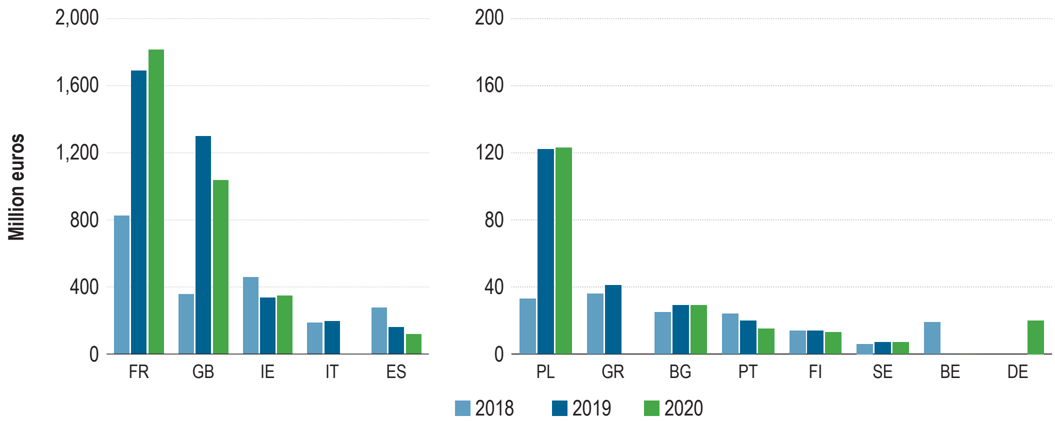
183 In 2019, the relative cost to finance CMs, expressed per unit of demand (Figure 38), was still very high in Ireland as in previous years, reaching a level equal to 24% of the average DA price. When compared to DA prices, CM costs were also significant in Great Britain (9%), France (9%) and Greece (5%).

157 For more information on TERNA capacity auction results, please see footnote 156.

158 For additional information, please see: https://forum-energii.eu/public/upload/articles/files/Capacity%20market%20for%20review_net.pdf.

159 Based on annual costs from auction results, see footnote 155, considering only the delivery period October-December 2020 and taking into account additional costs e.g. for testing.

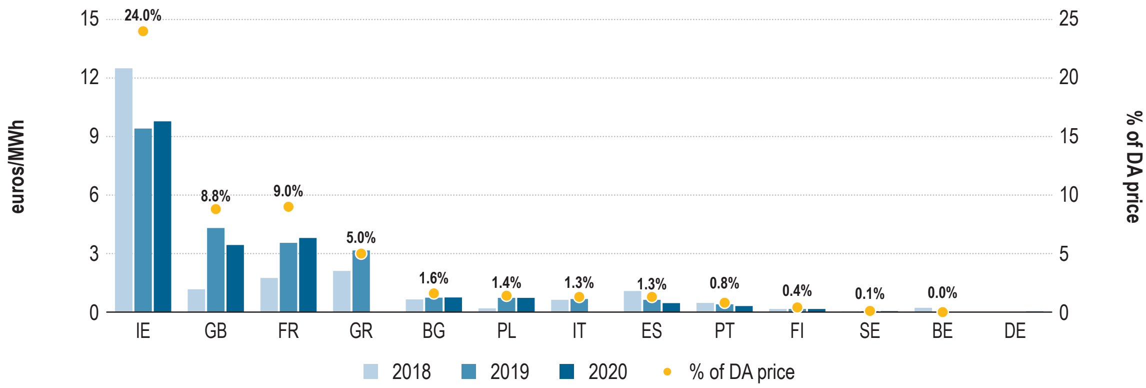
Figure 37: Costs incurred or forecasts to finance CMs – 2018–2020 (million euros)



Source: ACER calculations based on NRAs data.

Note: Costs are based on the total annual realised payments to capacity providers for delivery of capacity in the relevant year. Please see the note applying to Figure 37 and Figure 38 below. Values marked with the label 'IE' refer to 'SEM'.

Figure 38: Costs incurred or forecasted to finance CMs per unit demand – 2018–2020 (euros/MWh) and expressed as a percentage of the yearly average DA price in Europe – 2019 (% of DA price)



Source: ACER calculations based on NRAs and ENTSO-E data.

Note applying to Figure 38: The costs expressed as percentages of day-ahead prices refer to 2019 data unless otherwise stated herein. Costs per unit demand are based on total annual realised payments to capacity providers for delivery of capacity in the relevant year; when and where the payments have not been realised yet, the values are the best estimates of the expected payments provided by NRAs. Demand data are derived from ENTSO-E's Transparency Platform which includes system losses (see footnote 36) thus the depicted results for 2018 may differ from the ones of the previous edition of the MMR, where Eurostat demand data was used.

Note applying to Figure 37 and Figure 38: The costs are gross and do not account for side effects such as impacts on energy prices and/or additional costs or benefits derived from the CMs. As of this year's edition, the costs for network or system reserves (relevant for at least Germany, Latvia, Lithuania) are reported as remedial action costs and not as CM related costs. In Belgium, there was no auction for 2019, resulting in zero costs. The overall costs for France are an approximation considering that all capacity certificates are valued at the market reference price, while a significant share (which varies year-on-year) of these capacity certificates is implicitly valued through the ARENH mechanism, which is a scheme that enables suppliers to purchase electricity from nuclear generators at a regulated price. Therefore, the actual costs for France are dependent on the reference used to value the capacity certificates related to the ARENH mechanism. Great Britain's cost figures for 2018 refer to the period until 15 November 2018, i.e. the time of the CM's suspension, while for 2019 they refer to the period from December 2018 until the end of November 2019, although the actual payments were made in early 2020. For 2018 these costs were scaled up accordingly to approximate yearly costs. For Greece, the provided costs referred only to the reference period i.e. October–December for 2018 and January–March 2019, and were scaled up to approximate yearly costs. Cost data for Italy refer to remaining capacity payments from a previous capacity remuneration scheme. Cost data for 2019 and 2020 for Lithuania were not available. In Spain, the CM was cancelled in June 2018. The depicted costs refer to the remaining long term investment incentives awarded to installations before 2016. Values marked with the label 'IE' refer to 'SEM'.

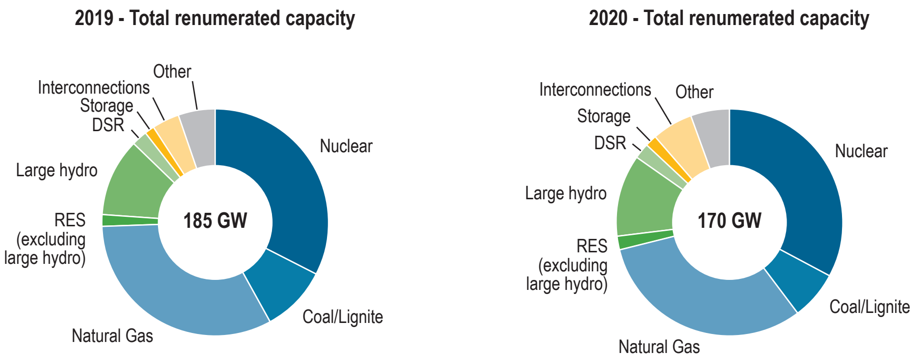
6.2 Technologies remunerated under capacity mechanisms

184 The provisions of Article 22(4) of the recast Electricity Regulation regarding the exclusion of generation units exceeding certain CO_2 emissions limits from receiving payments from CMs are expected to become effective gradually as MSs adopt these provisions. Therefore, a reduction of the share of high-emitting technologies that receive CM payments is expected in the coming years[160]. At the same time, according to the principles for designing CMs described in Article 22(1h) of the recast Electricity Regulation, CMs shall be open to participation of all resources including energy storage and demand side response. Finally, pursuant to Article 26, direct cross-border participation of foreign resources shall be allowed in CM rules, including for SR when technically feasible[161].

185 While the results of the full implementation of the recast Electricity Regulation will gradually become visible, ACER initiated a data collection process in order to provide insights on the technologies currently remunerated under CMs, with a view to monitor developments concerning the aforementioned provisions of the recast Electricity Regulation.

186 Figure 39 displays the breakdown of technologies remunerated through CMs for eleven MSs with a CM. Nuclear power plants account for a third of the remunerated capacity in both years while the largest share of the remunerated resource capacity refers to fossil fuels (approximately 47% and 44% for 2019 and 2020, respectively) with coal and lignite power generation units accounting for 9% and 7% of the total capacity for 2019 and 2020, respectively. In addition, cross-border participation, currently only in the form of interconnections, already occurs in three cases[162], reaching 4% of the total capacity remunerated under CMs in 2019 and increasing to 6% in 2020. More precisely, direct participation of interconnectors takes place in the British (6% for 2020), French (6% and 7% for 2019 and 2020 respectively), and the Irish SEM (5% for both 2019 and 2020) CMs. Demand side response and to a lesser extent RES and storage also play a role in CMs across the EU, with a share of approximately 2% each in both years.

Figure 39: Capacity remunerated through CMs in a number of MSs per type of technology – 2019–2020 (GW)



Source: ACER calculations based on NRAs data.

Note: The graphs are based on data for Belgium, Bulgaria, France, Finland, Greece, Ireland, Poland, Portugal, Spain, Sweden and the United Kingdom (Great Britain).

160 The provisions of the recast Electricity Regulation on adequacy shall apply without prejudice to commitments or contracts concluded by 31 December 2019.

161 Pursuant to the same Article, interconnectors may be allowed to directly participate in existing CMs for another two years from the date of approval of the methodologies.

162 Cross-border participation is also foreseen in the Italian and Polish CMs. However, these are not included herein since the first delivery auction of the Italian CM refers to 2022 and cross-border participation in the Polish CM is pending due to the lack of agreements between the Polish and neighbouring TSOs.

6.3 Capacity mechanisms and resource adequacy concerns

187 According to Article 21(4) of the recast Electricity Regulation, "Member States shall not introduce capacity mechanisms where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern". Similarly, Article 21(6) states that "Where a Member State applies a capacity mechanism, it shall review that capacity mechanism and shall ensure that no new contracts are concluded under that mechanism where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern […]". Moreover, according to Article 25 of the recast Electricity Regulation "When applying capacity mechanisms Member States shall have a reliability standard in place." and this reliability standard "…shall be calculated using at least the value of lost load and the cost of new entry over a given timeframe and shall be expressed as 'expected energy not served' (EENS) and 'loss of load expectation' (LOLE)."

188 While according to Article 11(1) of the recast Electricity Regulation MSs applying or planning to apply a CM were expected to calculate the value of lost load (VoLL) and consistently define reliability standards by 5 July 2020, these values were not yet available at the time of producing this MMR due to delays in the finalisation of the methodologies underlying the calculation of the VoLL and the reliability standard[163].

189 In the absence of the above-mentioned values, ACER requested NRAs to provide information on the existence of, binding or indicative, reliability standards currently used to assess the need for interventions to tackle resource adequacy concerns. The results, presented in Table 4, show that only ten MSs had a reliability standard in place as of the end of 2019.

Table 4: Reliability standards used in the EU – 2019

Member State	Type of reliability standard	Value	Binding (B)/Non-binding (NB)
BE	LOLE LOLE (P95)	3 hours/year 20 hours/year	B B
BG	SAI = 1 - LOLP	0.99815	B
CY	Reserve margin	189 MW	B
DE	LOLE	5 hours/year	NB
DK	Outage minutes	7 minutes	B
FR	LOLE	3 hours/year	NB
GR	LOLE	3 hours/year	NB
IE	LOLE	8 hours/year	B
IT	LOLE	3 hours/year	B
LT	LOLE	8 hours/year	NB
NL	LOLE	4 hours/year	NB
PL	LOLE	3 hours/year	NB
ES	Reserve margin/LOLE	(see note)	NB
UK (GB)	LOLE	3 hours/year	B

Source: NRAs and Federal Ministry of Economics and Energy for Germany

*Note: Loss of load expectation or LOLE is the average number of hours per year, during which loss of load, i.e. load shedding, occurs in a given area (based on modelling results). P95 indicates the 95th percentile of a range of LOLE estimates i.e. 5% of the estimates are above this value. Loss of load probability or LOLP is the probability that available capacity will not be able to cover demand. In Bulgaria, the system adequacy indicator or SAI refers to the annual average since different values per semester are actually used. The SAI level corresponds to approximately 16 hours of LOLE. The reserve margin in Cyprus is the as the level of additional capacity which is readily available during the peak period of capacity demand. In Denmark the reliability standard is set in 'outage minutes (OM)' defined as OM = 8760 * 60 * EUE / Demand, where Demand is the annual load and EUE is the expected unserved energy i.e. the EENS adjusted to account for the fact that real load shedding occurs at predefined blocks of energy. The uniform 7 minutes target refers to outages related to either resource adequacy (5 minutes), transmission adequacy (1 minute) or system operation incidents (1 minute). For Germany, the reliability standard has been derived from a threshold presented in the 2019 security of supply monitoring report[164]. Herein, a LOLP of 0.06 % has been calculated using cost of new entry (CONE) and VOLL (CONE / VOLL = 50,000 euros/MW/year / 10,000 euros/MWh ≈ 0.06 %). The LOLE thereof is 0.06% of 8760 hours ≈ 5 hours. The value for Ireland refers to the SEM and is used for the purpose of the current CM. In Spain a 10% reserve margin, not legally established, was used recently, while a LOLE indicator is currently under discussion; for the non-mainland territories there is a requirement of maximum LOLP of one day every 10 years, equivalent to a LOLE of 2.4 hours/year. The value of United Kingdom refers to Great Britain only.*

163 While Article 23(5) of the recast Electricity Regulation stipulates that the relevant methodology for calculating the VoLL and the reliability standards should have been submitted to ACER by 5 January 2020, ENTSO-E formally submitted the methodologies on the 4 May 2020.

164 Definition and monitoring of security of supply on the European electricity markets, Federal Ministry of Economics and Energy, Chapter 2.3.4 – Quantitative definition of the SoS standard, page 39, https://www.bmwi.de/Redaktion/EN/Publikationen/Studien/definition-and-monitoring-of-security-of-supply-on-the-european-electricity-markets-from-2017-to-2019.pdf?__blob=publicationFile&v=9.

190 As in the 2018 MMR, ACER conducted a preliminary analysis of the results of the ENTSO-E 2019 MAF[165] in order to get insights on adequacy at MS level based on a common assessment. Figure 40 and Figure 41 depict the levels of LOLE and EENS relative to total annual demand, compared to conservative thresholds[166], for 2021 and 2025, for the MSs that employ approved or operational CMs. The reported reliability standard expressed as LOLE (if any) is also depicted in Figure 40.

191 The analysis indicates that for nine out of the thirteen MSs that introduced a CM[167], i.e. Bulgaria, Germany, Finland, Greece, Ireland (SEM), Poland, Portugal, Spain and UK (Great Britain), the 2019 MAF results do not show an adequacy issue. The results are illustrated in Figure 42.

192 In the case of Italy, the levels of LOLE and EENS estimated in the 2019 MAF are significant in two of the Italian bidding zones, i.e. in Italy Center-North (EENS is estimated to be 0.004% in 2021 and 2025 while LOLE is estimated to be 2.05 hours/year and 2.51 hours/year in 2021 and 2025, respectively) and in Sicily (EENS is estimated to be 0.008% in 2021 and 2025 while LOLE is estimated to be 4.22 hours/year and 8.97 hours/year in 2020 and 2025, respectively). Similarly, in Sweden, the EENS is estimated to be significant in the SE3 bidding zone (0.001% for both 2021 and 2025) and LOLE is estimated to be significant in the SE4 bidding zone (1.74 hours/year in 2021). Such differences across bidding zones should be considered when addressing potential adequacy issues.

193 Two important caveats on the MAF results underlying the above analysis apply. The first one is that the results refer to the MAF ‘base case’ scenario. The second is that, for some MSs, the 2019 MAF results for 2025 are visibly different from the 2018 MAF ones for the same year. This leads to different conclusions with respect to the presence of adequacy issues in the concerned MSs[168]. This is mainly due to the different assumptions of the two versions of the MAF, e.g. on the evolution of the generation capacity in 2025, as well as some significant improvements in the methodological framework of the latest MAF version[169]. While adjustments in the assumptions, data and methodology underlying adequacy assessments are welcome and partly unavoidable, a stable framework to ensure confidence in the conclusions derived from pan-European resource adequacy assessments is needed. In this context, ACER will strive to ensure that following the ERAA methodology, a common European framework for the resource adequacy assessment is established, leading to robust and reliable resource adequacy assessments at Union level (as well as at national level since NRAAs shall be based on ERAA methodology)[170].

165 For the purposes of this preliminary analysis the values of LOLE and EENS (expected energy not served, i.e. the average amount of energy expected not to be supplied per year) were compared with the same thresholds as in the 2018 MMR. Potential adequacy issues are assumed when the following two conditions are simultaneously met (i) LOLE ≥ 1hour for at least one year (2021 or 2025) and (ii) EENS ≥ 0.001% of annual demand for at least one year (2021 or 2025) . On the contrary, if, for a given MS, either of the reliability indicators is below the respective threshold for both of the examined years, i.e. 2020 and 2025, there is some indication that no adequacy issues may be perceived at the regional level for this MS.

166 In fact, the thresholds are significantly more conservative than the values reported in Table 4.

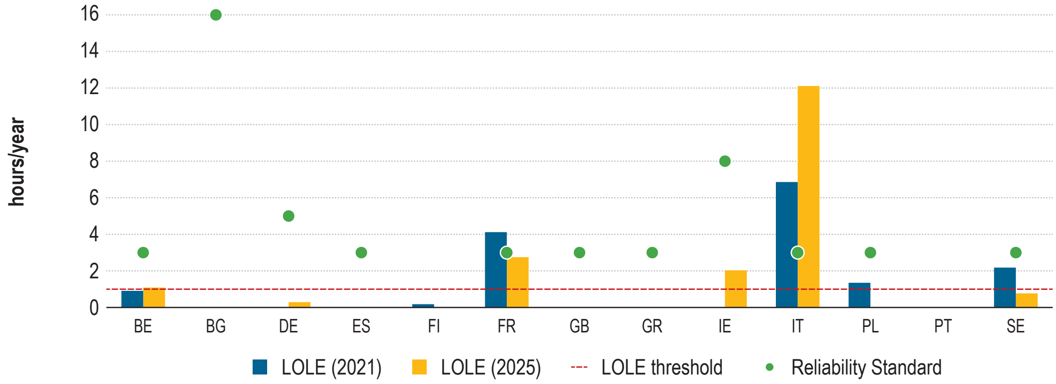
167 The Greek temporary CM was approved until October 2019 but was suspended since March 2019 (see also Figure 36).

168 E.g. while for Lithuania in the 2918 MAF LOLE for 2025 was negligible, in 2019 MAF the same indicator reaches a value of 7.5 hours/year.

169 For more details, please see: https://www.entsoe.eu/Documents/SDC%20documents/MAF/2019/MAF%202019%20Appendix%202%20-%20Methodology.pdf.

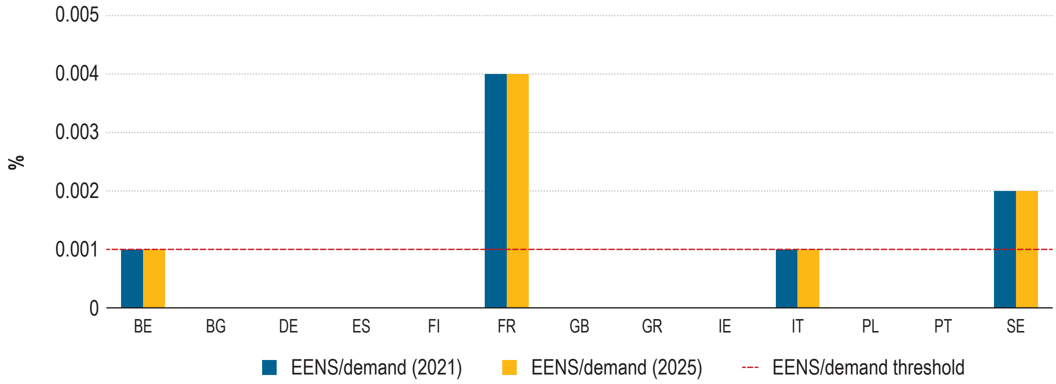
170 Pursuant to Article 23(7) of the recast Electricity Regulation the scenarios, sensitivities and assumptions on which they are based, and the results of the ERAA shall be subject to the prior approval by ACER.

Figure 40: LOLE for MSs with approved or operational CMs according to ENTSO-E's 2019 MAF and reliability standards for a number of MSs (hours/year)



Source: ACER calculations based on ENTSO-E's 2019 MAF results and NRAs data.

Figure 41: EENS relative to total annual demand, for MSs with approved or operational CMs according to ENTSO-E's 2019 MAF (%)



Source: ACER calculations based on ENTSO-E's 2019 MAF results and dataset.

Figure 42: Perceived need for CMs based on the 2019 MAF results – 2019

Source: ACER based on ENTSO-E´s 2019 MAF.

Note: In Greece, CM auctions have been postponed since March 2019 and no CM has been in place since November 2019. In Portugal**, the CM in place has been postponed since 2018. In Spain***, the CM used to comprise "investment incentives" and "availability payments"; the availability payments were removed in June 2018 and the investment incentives apply only to generation capacity installed before 2016..*

194 Lastly, Articles 23 and 24 of recast Electricity Regulation call for a common methodology for assessing adequacy at both Union and national levels. According to Article 23(5) of the Electricity Regulation, interconnections should be properly taken into account in the adequacy assessments. Furthermore, according to Article 24 of the recast Electricity Regulation NRAAs must have a regional character, while coordination between neighbouring competent bodies is foreseen. In this respect, interconnections should be taken into account in the assessment of adequacy in all MSs.

195 In line with the recast Electricity Regulation, the ERAA methodology ensures that the ERAA explicitly models interconnections and the related cross-zonal capacity in a probabilistic way. At the same time cross zonal capacities shall reflect the minimum capacity pursuant to Article 16(8) of the recast Electricity Regulation (taking into account action plans or derogations pursuant to Articles 15 and 16(9) of the recast Electricity Regulation accordingly[171]), as well as the expected impact of measures to reach electricity interconnection targets. Consequently, the assessment of the contribution of interconnections in resolving adequacy concerns is expected to improve at European level in the future ERAAs and NRAAs.

196 Despite the above improvements expected in the near future, the contribution of interconnectors continued to be underestimated in national adequacy assessments. In particular, in four MSs, i.e. Austria, Latvia, Romania and Spain[172], as well as in Norway, interconnectors are still not taken into account in their national adequacy assessments[173]. Out of these four MSs, Spain[174] has a CM in place.

171 Pursuant to Article 4(6a) of the European resource adequacy assessment methodology (see footnote 19) *"In particular, cross-zonal capacities shall reflect the latest available information regarding MS action plans for a linear trajectory pursuant to Article 15 or the minimum capacity pursuant to Article 16(8), as well as any temporary derogations granted as per Article 16(9) of the Electricity Regulation."*

172 Spain considers interconnections in the adequacy assessment methodology; however, it does not account for them in the decisive scenario for the justification of interventions regarding resource adequacy issues.

173 No official adequacy assessment exists in the Czech Republic.

174 The Spanish CM is not operational, see Figure 36.

Annex 1: Additional figures and tables

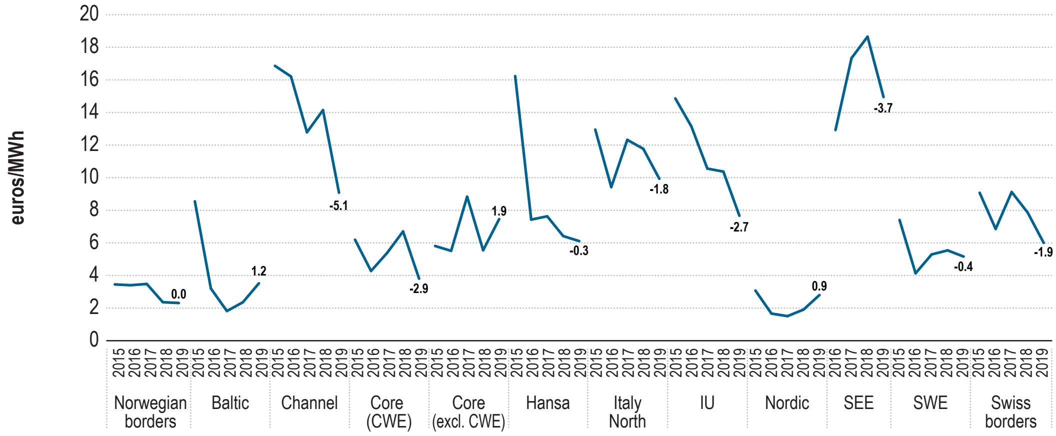
Table 5: Average DA price differentials across European borders (ranked) – 2016–2019 (euros/MWh)

	Average price differentials (euros/MWh)				Average of absolute price differentials (euros/MWh)			
Border	2016	2017	2018	2019	2016	2017	2018	2019
BG-GR	-6	14.6	-20.5	-16.3	14.6	19.8	24.2	20.4
DE-PL	-7.5	-2.8	-7.7	-15.8	10	8.7	9.9	16.1
GR-IT	2.5	5.5	1	12.9	8.2	9	8.4	14.3
PL-SE4	6.9	4.6	5.8	13.7	9.2	5.5	7.1	14.2
CZ-PL	-5.3	-0.5	-6.1	-13.3	9.1	8.4	8.9	13.8
PL-SK	5	-4.1	3.7	12.0	9.1	11.1	8.7	13.3
FR-IT	-5.9	-9.4	-10.5	-11.8	7.3	9.8	11	11.9
AT-IT	-13.7	-20.2	-14.4	-11.2	13.7	20.2	14.4	11.4
AT-HU	-6.4	-16.2	-4.7	-10.3	7.4	16.9	6.9	11.3
CH-IT	-4.8	-8.8	-8.5	-10.4	6.2	10.2	9.5	10.8
ES-FR	2.9	7.3	7.1	8.2	8	10.2	10.8	10.1
FR-GB	-12.4	-6.8	-14.7	-9.4	15.4	12.5	15.6	9.9
BG-RO	-0.3	-8.3	-6.5	-2.9	11.4	14.8	13.1	9.6
HU-SK	4	9.4	2.5	8.8	4	9.4	2.6	8.8
AT-SI	-6.6	-15.3	-4.8	-8.7	7.4	15.3	5	8.7
LT-PL	0.1	-1.7	-2.2	-7.3	6.1	4.2	4.5	8.6
GB-NL	16.9	12.4	12.4	7.7	17	13.1	12.7	8.2
GB-IE	4	5.9	2.9	-1.4	13.8	10.5	10.4	7.7
FI-NO4	7.4	7.5	3.1	5.7	7.6	7.6	4.5	7.7
IT-SI	7	4.9	9.5	2.5	7.2	7	9.8	6.5
LT-SE4	7	2.9	3.6	6.3	7.1	3	3.8	6.4
DE-SE4	-0.5	1.9	-1.9	-2.1	4.9	7.9	6.7	6.1
FI-SE1	3.5	2.3	2.6	6.1	3.5	2.3	2.6	6.1
CH-DE	8.9	11.8	7.7	3.2	9.5	13	9	5.8
DK1-NO2	1.5	1.3	0.8	-0.8	3.1	4.8	4.9	5.8
HR-HU		1.5	1	-1.1		5	4.7	5.7
FI-SE3	3.2	1.9	2.3	5.7	3.2	1.9	2.3	5.7
NL-NO2	7.1	10.4	9.3	1.9	7.5	10.6	10.6	5.5
DE-FR	-7.8	-10.8	-5.7	-1.8	8	10.9	6.8	5.0
DK1-SE3	-2.6	-1.2	-0.5	0.1	2.7	2.9	4.1	4.8
CZ-DE	2.2	2.3	1.6	2.6	3.9	4.5	4.1	4.5
DE-NL	-3.3	-5.1	-8.1	-3.5	3.8	6.6	8.3	4.2
AT-CH	-8.9	-11.8	-5.9	-0.8	9.5	13	7.4	3.9
BE-NL	4.4	5.3	2.7	-1.8	6.1	7	6.3	3.6
AT-CZ	-2.2	-2.3	0.3	-0.2	3.9	4.5	4.2	3.5
CH-FR	1.1	1	2	1.4	4.9	4.5	5.2	3.5
DE-DK2	-0.4	2.1	-1.7	-2.2	4.3	6.2	5.1	3.4
BE-FR	-0.1	-0.4	5.1	-0.1	2.6	3.8	5.6	2.8
DK2-SE4	-0.1	-0.2	-0.2	0.0	0.7	1.7	2.1	2.7
NO1-SE3	-3.1	-2.2	-0.9	0.9	3.3	2.9	1.5	2.6
AT-DE	0	0	1.8	2.4	0	0	1.8	2.5
DE-DK1	2.3	4	0.4	-0.8	3.9	6.6	4.1	2.5
HU-RO	2.1	2.4	4.6	0.0	2.5	3	5	2.0
EE-FI	0.6	0	0.3	1.8	0.7	0.1	0.4	1.8
NO4-SE1	-3.9	-5.1	-0.5	0.4	4.1	5.4	1.9	1.6
NO4-SE2	-3.9	-5.1	-0.5	0.4	4.1	5.4	1.9	1.6
NO3-SE2	-0.3	-1.3	-0.1	0.6	0.9	1.7	0.9	1.4
CZ-SK	-0.3	-4.5	-2.4	-1.3	0.6	4.5	2.5	1.3
EE-LV	-3	-1.5	-2.8	-0.4	3.1	1.5	2.9	0.6
HR-SI		-0.1	0.8	0.5		10.3	3.1	0.5
ES-PT	0.2	-0.2	-0.2	-0.2	0.3	0.4	0.3	0.2
LT-LV	-0.4	0.4	0.1	-0.2	0.5	0.5	0.2	0.2

Source: ACER calculations based on ENTSO-E data.

Note: No data were available for the Croatian borders in 2016.

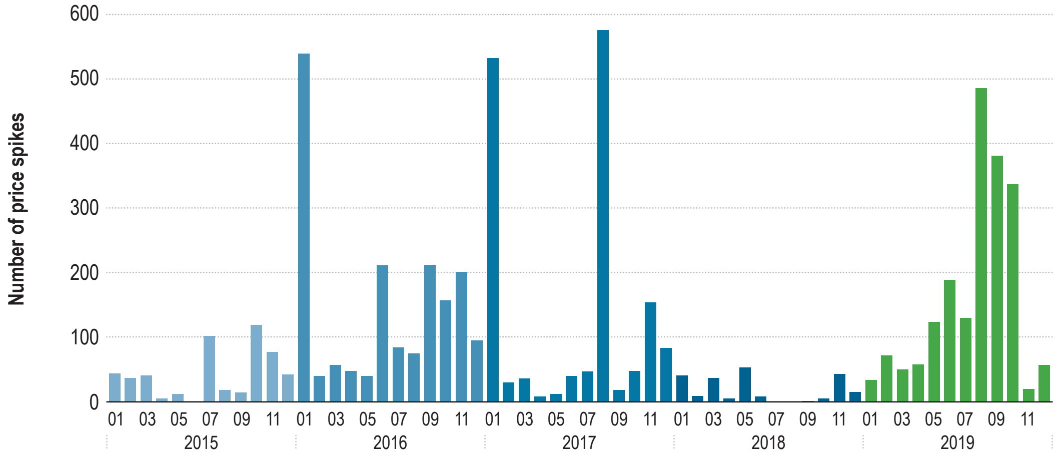
Figure 43: Yearly evolution of absolute DA price spread per CCR – 2015–2019 (euros/MWh)



Source: ACER calculations based on ENTSO-E data.

Note: The absolute DA price spread per CCR is calculated as the average of the absolute DA price spread of all borders which are part of a given CCR. The number in the chart represent the price spread for 2019.

Figure 44: Monthly distribution of DA price spikes in Europe – 2015–2019 (number of occurrences)



Source: ACER calculations based on ENTSO-E data.

Table 6: Average oriented NTCs on European borders – 2018–2019 (MW and % change)

CCR	Directional border	NTC 2018	NTC 2019	Change
Baltic	EE - FI	977	997	2.1%
	EE - LV	764	800	4.8%
	FI - EE	981	998	1.8%
	LT - LV	589	584	-0.8%
	LT - PL	477	475	-0.4%
	LT - SE4	441	502	13.7%
	LV - EE	711	734	3.3%
	LV - LT	1025	1075	4.9%
	PL - LT	295	395	33.8%
	SE4 - LT	562	652	15.9%
Channel	FR - GB	1853	1841	-0.7%
	GB - FR	1853	1840	-0.7%
	GB - NL	1016	1021	0.6%
	NL - GB	1016	1021	0.5%

CCR	Directional border	NTC 2018	NTC 2019	Change
Core (excl. CWE)	AT - CZ	550	774	40.7%
	AT - HU	495	668	35.1%
	AT - SI	693	855	23.5%
	CZ - AT	576	716	24.3%
	CZ - DE/LU	2422	2497	3.1%
	CZ - PL	591	595	0.7%
	CZ - SK	1859	1990	7.0%
	CZ+DE+SK - PL	268	520	93.6%
	DE/LU - CZ	1720	1805	4.9%
	HR - HU	967	1000	3.4%
	HR - SI	1450	1432	-1.2%
	HU - AT	585	768	31.2%
	HU - HR	1200	1200	0.0%
	HU - RO	652	688	5.6%
	HU - SK	966	942	-2.4%
	PL - CZ	829	932	12.5%
	PL - CZ+DE+SK	469	1223	160.5%
	PL - SK	542	543	0.3%
	RO - HU	491	487	-0.8%
	SI - AT	839	936	11.5%
	SI - HR	1457	1482	1.7%
	SK - CZ	1200	1200	0.0%
	SK - HU	1266	1164	-8.1%
	SK - PL	493	494	0.2%
Core (technical profiles)	CZ+PL - DE-50Hertz	1358	1249	-8.0%
	DE-50Hertz - CZ+PL	1002	904	-9.8%
Greece-Italy (GRIT)	GR - IT	325	459	41.5%
	IT - GR	325	459	41.5%
Hansa	DE/LU - DK1	1275	1374	7.7%
	DE/LU - DK2	391	583	49.2%
	DK1 - DE/LU	939	1237	31.8%
	DK2 - DE/LU	381	543	42.6%
	PL - SE4	196	284	45.1%
	SE4 - PL	557	487	-12.7%
Italy North	AT - IT North	228	230	0.7%
	FR - IT North	2410	2368	-1.7%
	IT North - AT	95	100	5.9%
	IT North - FR	1020	1019	-0.1%
	IT North - SI	644	634	-1.7%
	SI - IT North	539	518	-4.0%
The Republic of Ireland and the United Kingdom	GB - SEM	924	939	1.6%
	SEM - GB	692	670	-3.2%
Nordic	DK1 - SE3	527	470	-10.9%
	DK2 - SE4	1008	1122	11.4%
	FI - SE1	1073	1052	-2.0%
	FI - SE3	1133	1028	-9.3%
	SE1 - FI	1503	1486	-1.1%
	SE1 - SE2	3151	3087	-2.0%
	SE2 - SE1	3299	3294	-0.2%
	SE2 - SE3	6197	6248	0.8%
	SE3 - DK1	637	531	-16.7%
	SE3 - FI	1181	1137	-3.8%
	SE3 - SE2	7300	7300	0.0%
	SE3 - SE4	4579	4597	0.4%
	SE4 - DK2	1081	1135	5.1%
	SE4 - SE3	1969	1799	-8.7%
	DK1 - DK2	574	572	-0.4%
	DK2 - DK1	588	583	-0.9%

CCR	Directional border	NTC 2018	NTC 2019	Change
Norwegian borders	DK1 - NO2	1250	1062	-15.0%
	NL - NO2	584	677	15.8%
	NO1 - SE3	1793	1659	-7.5%
	NO2 - DK1	1238	994	-19.7%
	NO2 - NL	572	676	18.1%
	NO3 - SE2	571	575	0.7%
	NO4 - SE1	468	482	3.1%
	NO4 - SE2	122	98	-19.6%
	SE1 - NO4	348	435	24.9%
	SE2 - NO3	784	727	-7.2%
	SE2 - NO4	175	152	-13.1%
	SE3 - NO1	1597	1368	-14.4%
	NO1 - NO2	1653	1782	7.8%
	NO1 - NO3	30	34	11.3%
	NO1 - NO5	528	489	-7.4%
	NO2 - NO1	2831	3112	9.9%
	NO2 - NO5	216	169	-21.5%
	NO3 - NO1	-30	64	-309.9%
	NO3 - NO4	44	183	318.8%
	NO3 - NO5	63	126	100.9%
	NO4 - NO3	878	924	5.3%
	NO5 - NO1	3044	3578	17.6%
	NO5 - NO2	309	358	15.9%
	NO5 - NO3	335	176	-47.6%
South-East Europe (SEE)	BG - GR	450	458	1.9%
	BG - RO	319	413	29.5%
	GR - BG	362	408	12.8%
	RO - BG	277	379	36.9%
South-West Europe (SWE)	ES - FR	2184	2245	2.8%
	ES - PT	2221	2613	17.7%
	FR - ES	2568	2202	-14.3%
	PT - ES	3066	3274	6.8%
Swiss borders	AT - CH	866	915	5.6%
	CH - AT	1043	761	-27.0%
	CH - DE/LU	3472	3491	0.6%
	CH - FR	1183	1163	-1.7%
	CH - IT North	2609	2469	-5.4%
	DE/LU - CH	1267	1343	6.0%
	FR - CH	2770	2678	-3.3%
	IT North - CH	1722	1721	0.0%

Source: ACER calculations based on ENTSO-E data.

Table 7: Number of active capacity constraints and shadow prices by element type in the Core (CWE) region – 2019

TSO	Element type	Number (2018)	Number (2019)	Difference	Total of shadow prices 2019 (euros/MW)	Average shadow price 2019 (euros/MW)
AT	Internal line	117	233	99%	22,252	96
BE	Internal line	1,109	1,126	2%	29,966	27
DE	Allocation constraint	457	0	-100%	-	-
DE-Amprion	Internal line	927	374	-60%	39,568	106
DE-TenneT	Internal line	301	251	-17%	29,517	118
DE-TransnetBW	Internal line	80	16	-80%	2,149	134
FR	Allocation constraint	0	0	-	-	-
FR	Internal line	1	9	800%	429	48
NL	Allocation constraint	190	0	-100%	-	-
NL	Internal line	1,452	455	-69%	30,279	67
Cross-border line		2,897	2,431	-16%	235,755	97
Total		**7,531**	**4,895**	**-35%**	**389,916**	**80**

Source: ACER calculations based on ENTSO-E data.

Table 8: Detailed data on the cost of remedial actions in European countries – 2019

Country	Total volume (GWh)	Costs (thousand euros)			Redispatching Costs (thousand euros)						
		Redis-patching	Counter-trading	Other actions	Related to network congestion at transmis-sion level	Related to voltage issues at transmis-sion level	Related to other issues at transmis-sion level	Related to issues at distribution level	Related to preserving internal exchanges	Related to preserving cross-border exchanges	Other
AT	2,494	55,400	-22	93,306	55,400	0	0	NA	NA	NA	NA
BE	171	2,644	546	123	2,644	0	0	0	2,644	0	0
CZ	2	42	0	0	42	0	0	0	0	0	42
DE	19,341	163,000	63,452	909,656	130,313	30,835	1,852	0	138,755	24,245	0
EE	30	NAP	871	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP
ES	7,614	239,610	7,303	0	12,716	96,073	38,542	92,278	239,610	0	0
FI	24	280	622	0	268	12	0	0	280	0	0
FR	545	0	24,773	0	0	0	0	0	0	0	0
GB	14,127	428,351	242	0	365,362	19,796	43,193	0	428,351	0	0
HU	4	511	0	0	0	0	511	0	511	0	0
IT	43	NAP	200	NAP	NAP	NAP	NAP	NAP	NAP	NAP	NAP
LT	5	0	177	68.833	0	0	0	0	0	0	0
LV	32	0	1,551	4,073	0	0	0	0	0	0	0
NL	537	31,725	0	29,339	31,564	0	161	0	908	30,655	161
NO	626	8,630	362	0	5,291	61	94	3,184	7,683	853	94
PL	15,943	113,666	329	0	NA	NA	NA	NA	113,033	594	40
PT	7	174	0	0	174	0	0	0	174	0	0
SE	222	2,226	322	0	NA	NA	NA	NA	2,226	0	0

Source: ACER based on NRAs data.

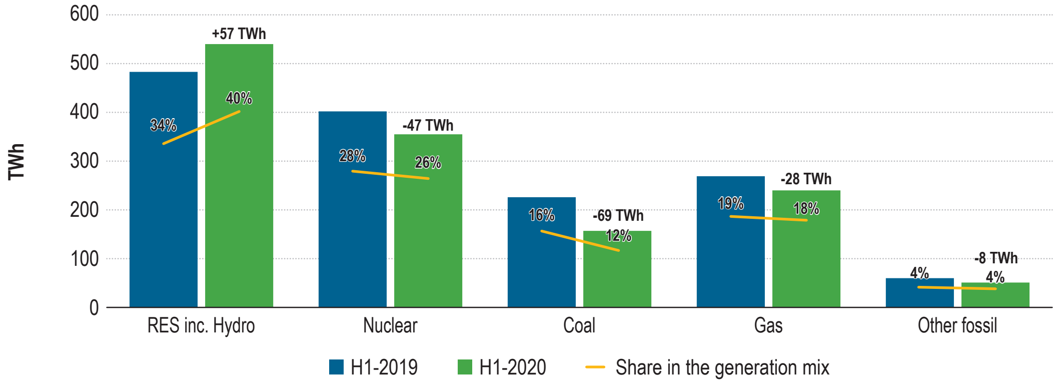
Note: Data include remedial actions for resolving congestion issues only. Costs refer to net costs paid by TSOs (i.e. including possible benefits received due to the remedial actions). Redispatching and countertrading data refer to issues taking place within the bidding zone, i.e. excluding actions conducted to resolve issues in other TSOs' grid, but including actions conducted by other TSOs to resolve internal issues and share of relevant cross-border actions. No costs related to costly remedial actions were incurred in Bulgaria, Croatia, Greece, Ireland, Luxembourg, Poland, Romania, Slovakia and Slovenia. Switzerland has not provided details on the costs. Other actions include network reserves in Austria, Germany (including both availability and activation payments) Latvia and Lithuania, cross-border redispatching in BE, RES curtailment in Germany and the so called "restriction contracts" in the Netherlands (contracts related to the availability for downward ramping in situations where there is a risk of inadequate capacity available for redispatching, e.g. in case of foreseen maintenance). Due to unavailability of data the Danish NRA provided only information on redispatching for transmission related congestion (14.97 GWh) and on redispatching conducted internally to solve issues located in a neighbouring TSO's area (1428.13 GWh of with a cost of 7.4 million euros).

Annex 2: Impact of the COVID-19 pandemic on electricity markets (first half of 2020)

197 In light of the extraordinary impact of the COVID-19 pandemic and of the resulting lockdown measures on energy systems, this edition of the MMR includes an update on key data of the European electricity markets up to June 2020.

198 Compared to the first half of 2019, the lockdown measures imposed by all MSs depressed EU electricity demand by 7% in the first half of 2020. Due to lower demand, a significant reduction in the production of electricity from fossil fuels (-19%) was observed. The largest drop was observed in the generation of electricity from coal, which decreased by 30% during the period. At the other end, the production of electricity from RES increased by 12%. As a result, for the first time ever, the share of electricity produced from RES (40%) was above the share of electricity produced from fossil fuels (33%) in the EU. Figure 45 shows the year-on-year change in the generation mix in the analysed period.

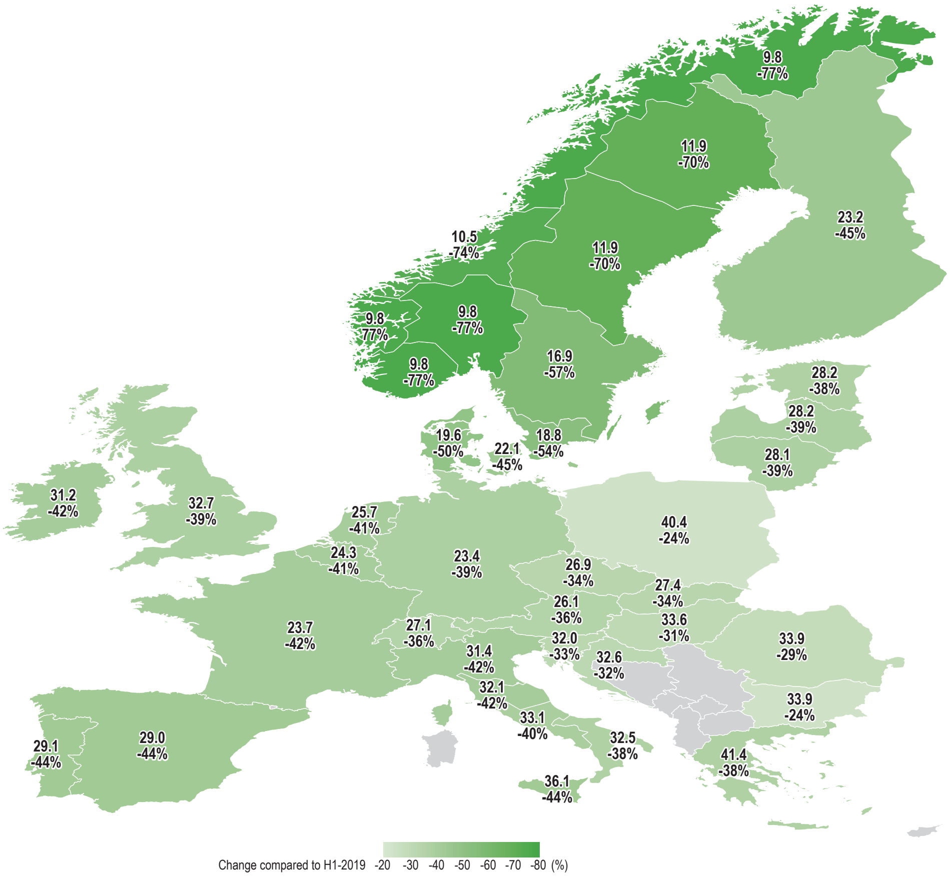
Figure 45: Net electricity generation per technology and the corresponding share in the generation mix in the EU-28 – H1-2019 and H1-2020 (TWh and %)



Source: ACER calculations based on ENTSO-E data.

199 In line with these developments, electricity markets witnessed historically low prices in almost all EU bidding zones. This decline is a consequence of very low electricity demand, in combination with other aspects, such as historically low fuel prices derived from the global impact of the COVID-19 pandemic on the economy. Figure 46 displays average day-ahead prices per bidding zone, and their year-on-year change, for the first half of 2020.

Figure 46: Average annual DA electricity prices and relative changes compared to the previous year in European bidding zones – H1-2020 (euros/MWh and % change compared to H1-2019)



Source: ACER calculations based on ENTSO-E data.

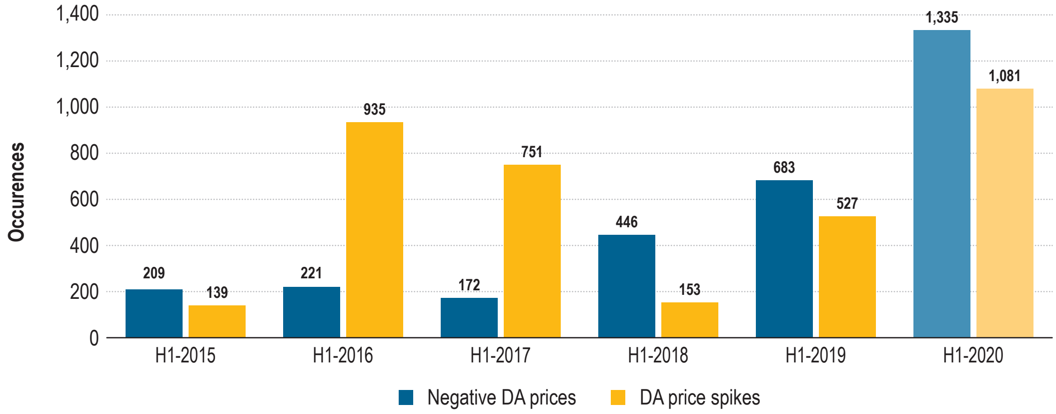
200 Moreover, Figure 47 shows that the number of hours with extreme (very low or very high) DA prices considerably increased in the first half of 2020. The increase in the number of hours with negative prices, which almost doubled compared to the same period of 2019, can be explained by a huge fall in the electricity demand. In particular, negative DA prices were observed for the first time in several bidding zones, including all bidding zones in the Baltics and most of the Nordic ones.

201 At the other end, the increase in the number of price spikes relates to the evolution of gas prices in the first half of 2020, which was 52% lower than in the first half of 2019[175]. Given that the threshold used by ACER to compute price spikes relates to the costs of producing electricity with gas[176], the increase in price spikes did not necessarily imply the presence of 'extraordinarily high' day-ahead prices in absolute terms. On the contrary, price spikes were recorded at 79 euros/MWh on average, which was 40% less than in 2018, but significantly above the costs of generating electricity with gas.

175 See Section 2.2 for more details.

176 See footnote 43.

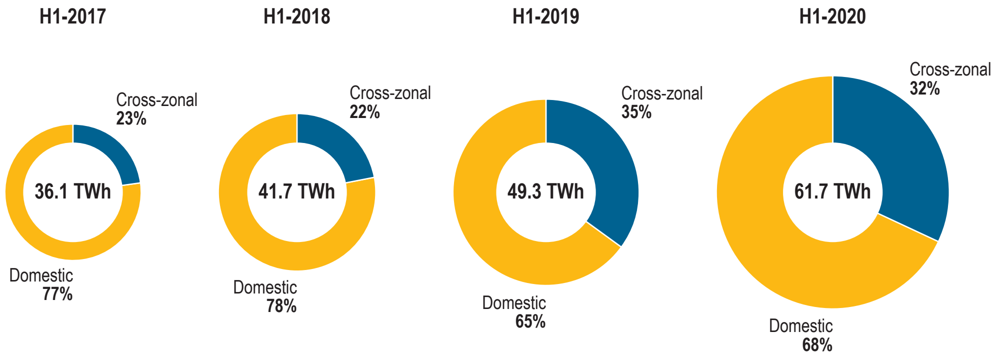
Figure 47: Frequency of negative DA prices and DA price spikes in the main wholesale DA markets in Europe – H1-2015–H1-2020 (number of occurrences)



Source: ACER calculations based on ENTSO-E data.

202 Finally, despite the pandemic, market integration process continued at pace. For example, thanks to SIDC, and despite the unprecedented drop in consumption, ID liquidity continued to increase. In particular, the continuous ID volumes traded in the first half of 2020 increased by more than 25% compared to the same period of 2019 (see Figure 48). The third wave of SIDC, which is expected to go live in the first quarter of 2021, should confirm the steady increase in ID trading activity in recent years, which is key to facilitating the integration of RES.

Figure 48: Share of continuous ID-traded volumes according to intra-zonal vs. cross-zonal nature of trades in Europe and yearly continuous ID-traded volumes – H1-2017–H1-2020 (% and TWh)



Source: ACER calculations based on NEMOs data.

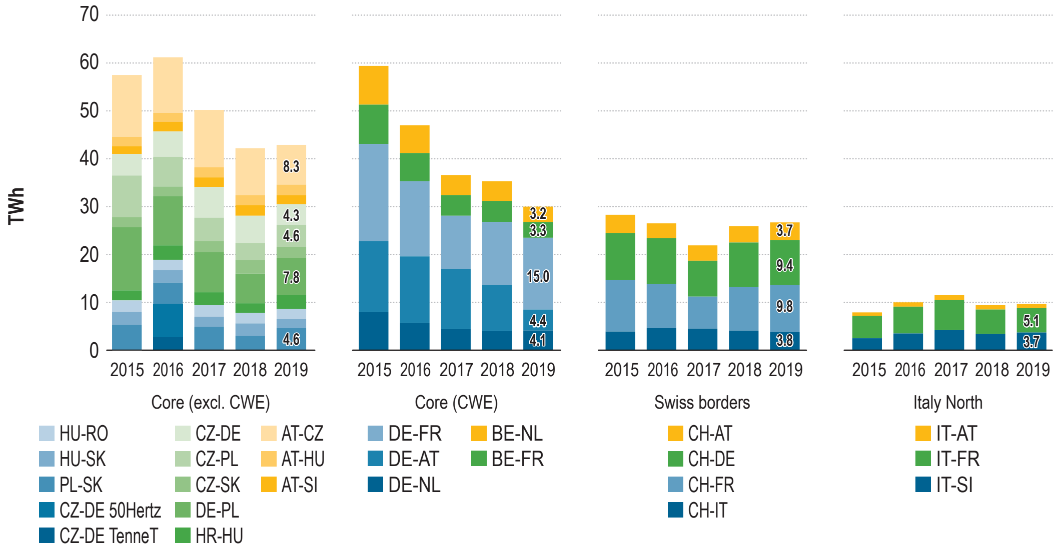
Annex 3: Unscheduled flows

203 As shown in previous editions of the MMR[177], UFs present a challenge to the further integration of the IEM. Their persistence reduces tradable cross-zonal capacity, market efficiency and network security.

204 The definitions of the flows used in this Annex and the detailed process description are provided in the methodological paper on UFs[178]. Briefly, UFs are comprised of unscheduled allocated flows (UAFs), most of which stem from insufficient coordination in capacity calculation and allocation processes, and loop flows (LFs), which originate from electricity exchanges inside other bidding zones.

205 The data on the allocated flows[179] (AFs) used in the analysis of this Annex were provided to ACER by ENTSO-E. AFs were calculated on an hourly basis, using some simplifications. Because of the simplifications used, the AFs data obtained can be considered only as a proxy for the total amount of AFs (and indirectly LFs and UAFs) observed on each border. For the Core (CWE) region, ENTSO-E provided improved information on schedules, thus refining the analysis and reducing the amount of UAFs for this region. ACER has been monitoring the evolution of UFs in Europe (on the borders in the Core and Italy North regions and on Swiss borders) since 2012. For these regions in 2019, UFs totalled 109 TWh, which represents an overall decrease of 3% compared to 2018.

Figure 49: Absolute aggregate sum of UFs for the Core (CWE and non-CWE borders), for Swiss borders and for Italy North regions – 2015–2019 (TWh)



Source: ACER calculations based on ENTSO-E and Vulcanus data.

Note: The UFs are calculated with an hourly frequency; the absolute values are then summed across the hours and aggregated for borders belonging to the relevant regions.

206 As shown in Figure 49, in the Core (excluding CWE) region, UFs essentially remained unchanged, as they increased by less than 2% compared to 2018. Overall, this region had the larger share of UFs, more than 39% of all UFs in Europe. In the Core (CWE) region, UFs decreased 15% year-on-year, mainly due to the decrease on the AT-DE border. In both the Swiss borders region and the Italy North region the UFs increased by 3%, compared to 2018.

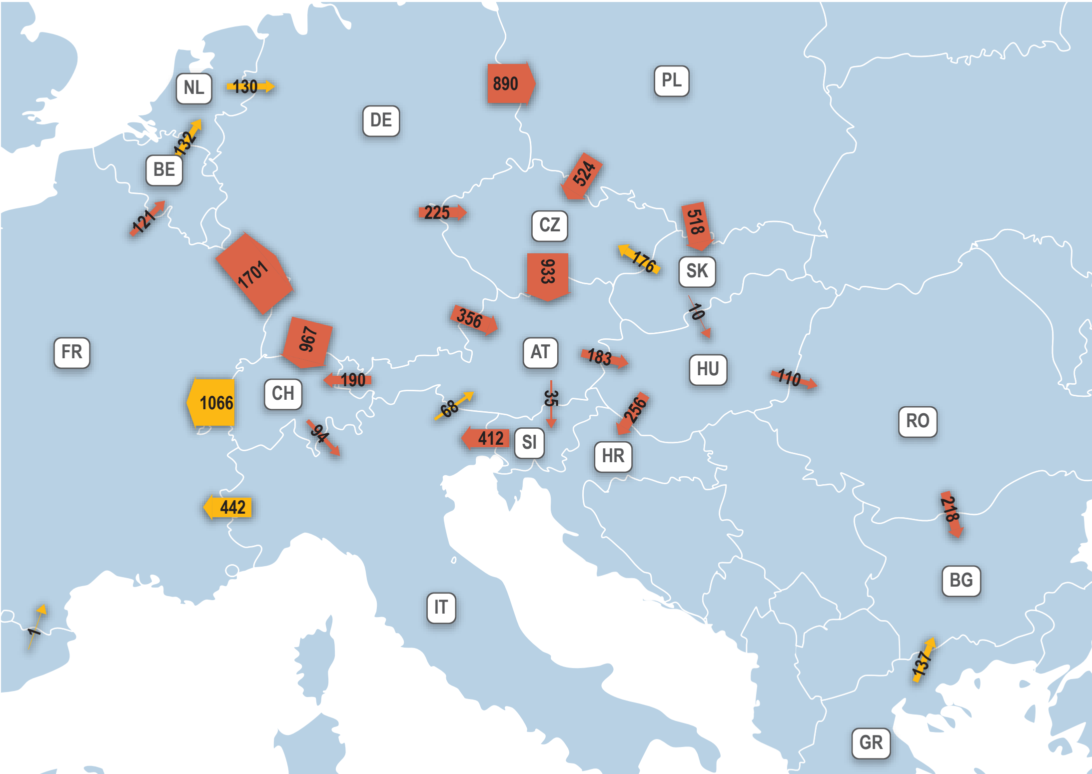
177 For more information, please see Section 5.1 'Unscheduled flows' (page 28) of the Electricity Wholesale Markets Volume of the 2015 MMR.

178 For additional information, please see the methodological paper on 'Unscheduled flows', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ACER%20Methodological%20paper%20-%20Unscheduled%20flows.pdf.

179 Allocated flows describe the actual flows coming from cross-zonal capacity allocation.

207 Figure 50 shows the prevailing direction of UF volumes. It reveals that the overall pattern still consists of two major loops, from Germany to Switzerland to the south west, and to Poland to the east. UFs on the German-Polish border increased by 26% year-on-year, returning to the 2017 levels. Unscheduled flows between the Netherlands and Germany on average had a different direction compared to 2018, related to the shift from coal to gas and the increase of exports for the Netherlands. Figure 51 and Figure 52 depict the UFs decomposition into UAFs and LFs.

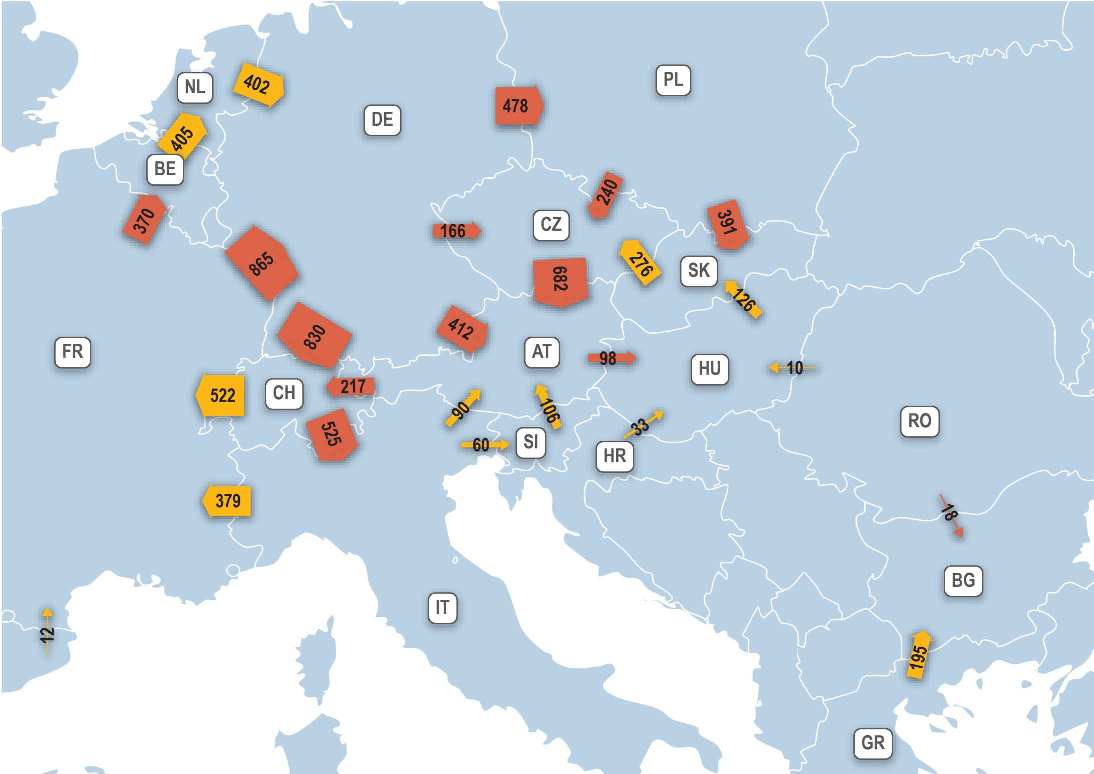
Figure 50: Average oriented UFs in Continental Europe – 2019 (MW)



Source: ACER calculations based on ENTSO-E and Vulcanus data.

Note: Average UFs are average hourly oriented values in 2019. The arrow width and label describe the average UF. The arrow is red when UFs flow in the same direction as the physical flow, and yellow when UFs flow opposite to physical flows. The direction of the UF is the same as that of the physical flow if the physical flow exceeds the cross-zonal schedule, or if both run in opposite directions. The direction of the UF is the opposite to the physical flow if the cross-zonal schedule exceeds the physical flow.

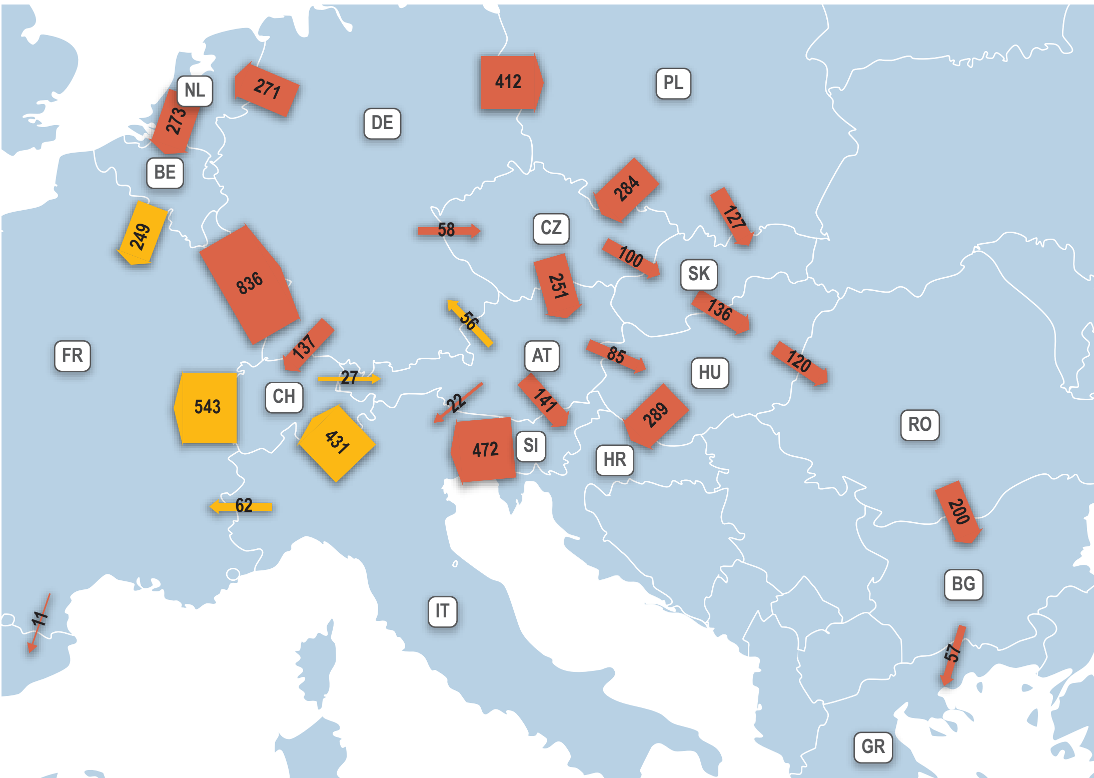
Figure 51: Average oriented UAFs in Continental Europe – 2019 (MW)



Source: ACER calculations based on ENTSO-E and Vulcanus data.

Note: Average UAFs are average hourly oriented values in 2019. The arrow width and label describe the average UAF. The arrow is red when UAFs flow in the same direction as the physical flow, and yellow when UAFs flow opposite to physical flows.

Figure 52: Average oriented LFs in Continental Europe – 2019 (MW)

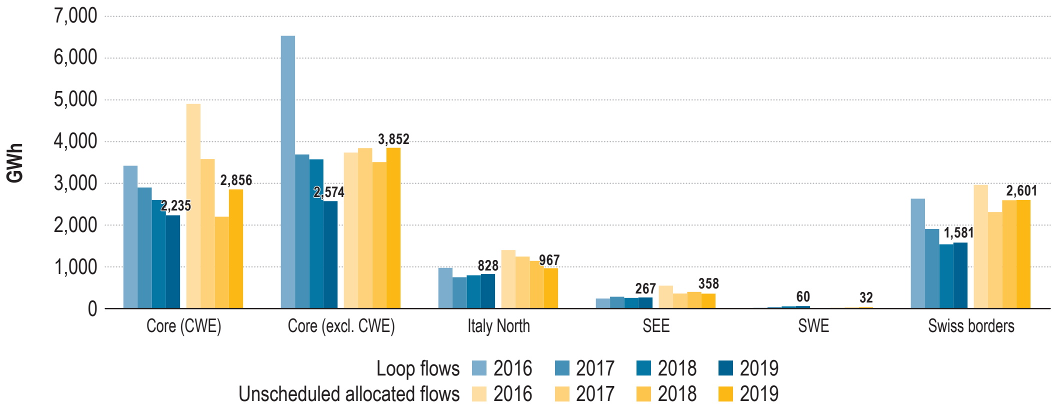


Source: ACER calculations based on ENTSO-E and Vulcanus data.

Note: Average LFs are average hourly-oriented values in 2019. The arrow width and label describe the average LF. The arrow is red when LFs flow in the same direction as the physical flow, and yellow when LFs flow opposite to physical flows.

208 Figure 53 describes the average absolute UAFs and LFs in Continental Europe. The largest UAFs and LFs were both observed in the Core (excluding CWE) region, which is the region with the largest number of EU borders. However, the LFs showed a considerable decrease in this region compared to 2018.

Figure 53: Average absolute LFs and UAFs in Continental Europe – 2016–2019 (GWh)



Source: ACER calculations based on ENTSO-E and Vulcanus data.

Note: For a given CCR, the UAFs (resp. LFs) are the sum of absolute UAFs (resp. LFs) on all individual borders. Neither UAFs nor LFs were observed in the GRIT region, because this region only has one DC border. Compared to the previous figures, the absolute UAFs and LFs are non-oriented.

209 Despite some improvements, UFs still significantly impede the efficient functioning of the Internal Electricity Market, mainly by 'consuming' flow on interconnectors. As a result, the capacity available for cross-zonal trade is limited. FB market coupling should lead to decreasing UAFs (in particular those resulting from exchanges within the region) but does not affect LFs. LFs may be tackled through bidding zone reconfiguration or other measures to ensure non-discrimination in capacity calculation.

Annex 4: Data Sources

210 Table 9 displays the data sources used throughout the present Electricity Wholesale Volume of the MMR, together with the associated data items.

Table 9: Data sources - Electricity Wholesale Markets Volume of the 2019 MMR

Source	Data items	Applicable Regulation	Public source
ENTSO-E Transparency Platform	• Day-ahead prices • NTC • Generation per production type • Scheduled DA and ID commercial exchanges • Nominated capacities • Prices of activated balancing energy • Actual total load (demand)	(EU) 543/2013	YES
ENTSO-E	• Flow-based parameters • Power transfer distribution factor (PTDF) indicator	(EU) 1222/2015	NO
ENTSO-E	• MAF results	(EU) 2009/714	YES
Joint Allocation Office	• Long-term auctions	(EU) 2016/1719	YES
Vulcanus (centralised database including cross-border flows)	• Scheduled DA and ID commercial exchanges • Physical flows • Realised scheduled exchanges	N/A	NO
EEX	• Forward bid-ask spreads • Forward traded volumes	N/A	NO
Eurostat	• Electricity demand – historical annual values	(EU) 222/2009	YES
NEMOs	• Intraday traded volumes and prices	(EU) 1222/2015	YES
NRAs	• Data on adequacy and capacity mechanisms • Various data items on balancing (cross-zonal exchange of balancing services, activated balancing energy, balancing capacity and balancing energy prices, lead-times for procuring balancing capacity) • Costs and volumes of remedial actions • Forward traded volumes	(EU) 2019/942	NO
PLATTS	• Clean spark and clean dark spreads	N/A	NO
European Climate Assessment Data	• Information on regional temperatures (daily values)	N/A	YES
Prospex	• Forward traded volumes • Day-ahead traded volumes	N/A	NO
ICIS	• Forward bid-ask spreads	N/A	NO
REMIT	• Day-ahead traded volumes	(EU) 1227/2011	NO

Annex 5: List of acronyms

Abbreviation	Definition
4MMC	4M Market Coupling
ACER	Agency for the Cooperation of Energy Regulators
AF	Allocated flow
aFRR	Automatically activated frequency restoration reserve
ARA	Oil and coal trading area in the triangle formed by the cities Amsterdam-Rotterdam-Antwerp. Alternative designations are NWE (North West Europe) or Rotterdam
ARENH	Regulated Access to Incumbent Nuclear Electricity
BSP	Balancing service provider
CACM	Capacity Allocation and Congestion Management (electricity)
CCM	Capacity calculation methodology
CCR	Capacity calculation region
CEE	Central-East Europe (electricity region)
CEER	Council of European Energy Regulators
CEP	Clean Energy Package
CM	Capacity mechanism
CNE	Critical network element
CNEC	Critical network elements with contigencies
CONE	Cost of new entry
CWE	Central-West Europe (electricity region)
DA	Day-ahead
DC	Direct current
DSR	Demand side response
EB	Electricity Balancing
ECAD	European Climate Assessment Data
EEA	European Emission Allowance
EENS	Expected energy not served
EEX	European Energy Exchange
EXAA	Energy Exchange Austria
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX SPOT	European Power Exchange
ERAA	European resource adequacy assessment
ETM	Electricity Target Model
EU	European Union
EUE	Expected unserved energy
FB	Flow-based
FBMC	Flow-based Market Coupling
FCA	Forward Capacity Allocation
FCR	Frequency containment reserve
Fmax	Maximum admissible active power flow
FRR	Frequency restoration reserve
GDP	Gross domestic product
GRIT	Capacity calculation region, consisting of the border Greece-Italy and the bidding zone borders within Italy
HVDC	High-voltage direct current
ID	Intraday
IEM	Internal Market for Electricity
IGCC	International Grid Control Cooperation project
INC	Imbalance netting cooperation
IU	The Republic of Ireland and the United Kingdom
JAO	Joint Allocation Office
LF	Loop flow
LFC	Load frequency control
LNG	Liquefied natural gas
LOLE	Loss of load expectation
LOLP	Loss of load probability
LTA	Long-term capacity allocation
MACZT	Margin available for cross-zonal trade
MAF	Mid-term Adequacy Forecast
MARI	Manually Activated Reserves Initiative

Abbreviation	Definition
mFRR	Manually activated frequency restoration reserve
MMR	Market Monitoring Report
MNCC	Margin from non-coordinated capacity calculation
MRC	Multi-Regional Coupling
MS	Member State
NBM	Nordic Balancing Model
NEMO	Nominated electricity market operator
NRA	National regulatory authority
NRAA	National resource adequacy assessment
NTC	Net Transfer Capacity
OM	Outage minutes
OTC	Over the counter
PCI	Project of common interest
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation
PPA	Power purchase agreement
PTDF	Power transfer distribution factor
RAM	Remaining Available Margin
REMIT	Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency
RES	Renewable energy sources
RPR	Risk Preparedness Regulation
RR	Replacement reserve
SAI	System adequacy indicator
SEE	South-East Europe
SEM	Irish Single Energy Market (comprising Northern Ireland and the Republic of Ireland)
SIDC	Single Intraday Coupling
SO	System operation
SoS	Security of supply
SR	Strategic reserves
SWE	South-West Europe (capacity calculation region) consisting of the border Spain-Portugal and France-Spain.
TERRE	Trans European Replacement Reserves Exchange
TSO	Transmission system operator
TTF	Title Transfer Facility (the Dutch gas hub)
UAF	Unscheduled allocated flows
UF	Unscheduled flows
VoLL	Value of lost load
XBID	European Cross-Border Intraday

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