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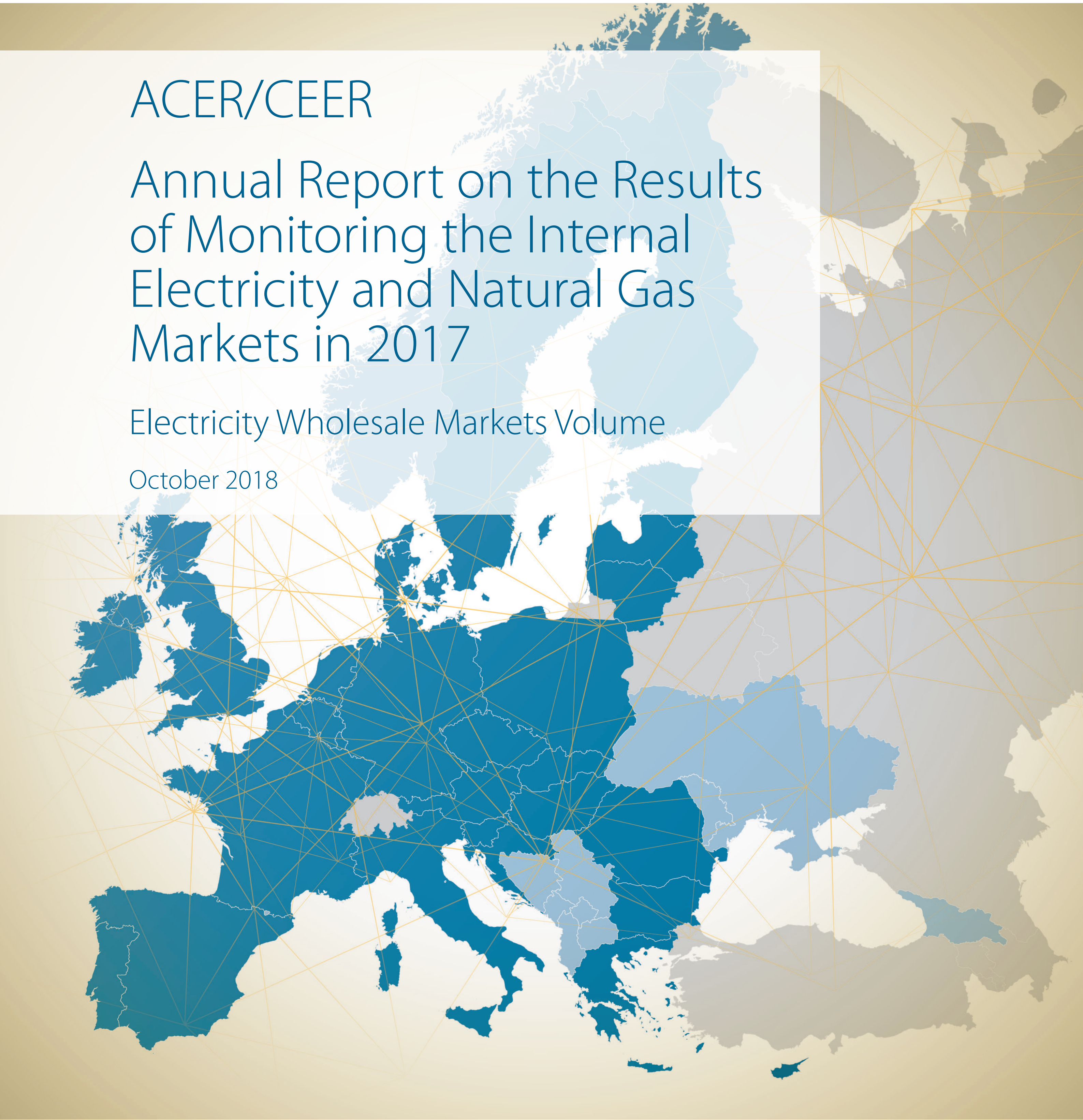
Electricity Wholesale Markets Volume

October 2018



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Executive Summary

Key developments in 2017

1 **In 2017, average day-ahead (DA) electricity prices increased in all bidding zones, except in the Bulgarian, Baltic and Polish markets.** The highest average DA prices were observed in Greece, Italy, the Iberian Peninsula, Croatia and Great Britain. Consistent with the increase in prices, the reappearance of price spikes in 2016 (approximately 1,200 price spike occurrences) continued in 2017, with approximately 1,100 price spike occurrences. The reoccurrence of price spikes observed in the past two years constitutes a significant change when compared to the 2011–2015 period (on average, approximately 300 price spikes per year). During some of the periods of price spikes in 2017, several Member States (MSs) took unilateral decisions to limit electricity exports. These decisions, which are not allowed under current legislation[1] and which are usually inefficient, emphasise the need to address adequacy issues in a robust, coordinated and cost-effective manner.

2 **In 2017, different levels of price convergence persisted across Europe.** Average absolute DA price spreads ranged from less than 0.5 euros/MWh on the borders between Estonia and Finland, Portugal and Spain, and between Latvia and Lithuania, to more than 10 euro/MWh on several borders, e.g. between the German/Austrian/Luxembourgish bidding zone and five of its neighbouring countries, and on all British borders, (see Table i). The persistent price differentials confirm the relevance of maximising the amount of tradable cross-zonal capacity, particularly on borders with the highest price spreads.

Table i: Borders with the largest absolute DA price differentials – 2012–2017 (euros/MWh)

	Average price differentials (euros/MWh)							Average of absolute price differentials (euros/MWh)						
Border	2012	2013	2014	2015	2016	2017	2012-2017	2012	2013	2014	2015	2016	2017	2012-2017
AT-IT	-31.5	-23.8	-17.6	-21.1	-13.7	-20.2	-21.3	31.5	24.1	17.7	21.1	13.7	**20.2**	21.4
AT-HU	-8.9	-4.6	-7.7	-9.0	-6.4	-16.2	-8.8	11.7	8.9	9.2	10.1	7.4	**16.9**	10.7
AT-SI	-10.4	-5.4	-7.7	-9.8	-6.6	-15.3	-9.2	12.6	8.5	8.7	11.7	7.4	**15.3**	10.7
GB-NL	7.1	7.1	11.0	15.6	16.9	12.4	11.7	9.1	8.8	11.2	15.8	17.0	**13.1**	12.5
CH-DE	6.9	7.0	4.0	8.6	8.9	11.8	7.9	9.1	9.3	5.6	9.8	9.5	**13.0**	9.4
FR-GB	-8.2	-15.8	-17.6	-17.2	-12.4	-6.8	-13.0	13.4	17.4	17.7	17.5	15.4	**12.5**	15.7
PL-SK	-1.4	-0.6	9.3	4.0	5.0	-4.1	2.1	6.9	8.1	11.1	8.1	9.1	**11.1**	9.1
DE-FR	-4.3	-5.5	-1.9	-6.8	-7.8	-10.8	-6.2	5.1	7.8	4.7	7.5	8.0	**10.9**	7.3
NL-NO2	18.8	14.6	14.0	20.3	7.1	10.4	14.2	19.1	15.1	14.1	20.3	7.5	**10.6**	14.4
GB-IE	-11.6	-10.0	-8.1	1.5	4.0	5.9	-3.1	16.9	18.6	17.7	15.2	13.8	**10.5**	15.4
ES-FR	0.3	1.0	7.5	11.8	2.9	7.3	5.1	11.4	17.6	16.7	14.7	8.0	**10.2**	13.1
CH-IT	-24.5	-16.9	-13.6	-12.5	-4.8	-8.8	-13.5	24.9	17.3	13.7	13.3	6.2	**10.2**	14.3

Source: ENTSO-E and ACER calculations (2018).

Note: A negative average DA price differential indicates that the average price was lower in the first member of the pair of bidding zones identifying a border, e.g. prices were lower in Austria than in Italy in all years. The borders are ranked based on the 2017 average absolute price differentials. Average absolute price differentials (right side of the table) are higher than the 'simple' spreads (left side of the table), where negative and positive price spreads are netted.

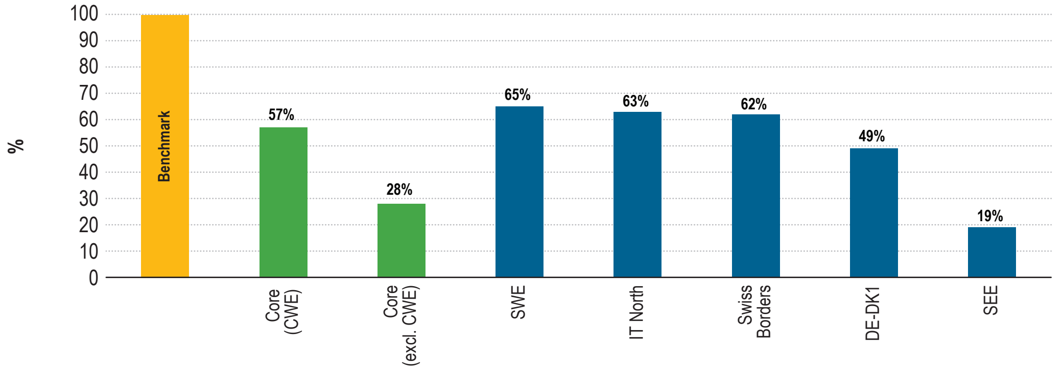
3 Although reaching full price convergence is not an objective as such, **the highest increases in the frequency of full price convergence between 2016 and 2017 were observed in the Baltic and Central-West Europe (CWE) regions.** Moreover, these two regions recorded the highest share of hours with full price convergence, respectively, 80% and 41% of the hours in 2017. The factors explaining these developments include the commissioning of new interconnector lines in the Baltic region and the benefits derived from the implementation of flow-based market coupling (FBMC) in the CWE region, in 2015, which continued in 2017.

1 Except in situations of emergency.

Available cross-zonal capacity and remedial actions

4 **In 2017, the cross-zonal capacity made available for trading remained significantly below the 'benchmark capacity', i.e. the maximum capacity that could be made available to the market while preserving operational security.** While last year's MMR showed that the performance of high-voltage direct current (HVDC) interconnectors in Europe is generally good, an average of only 49% of the 'benchmark capacity' in high-voltage alternating current (HVAC) interconnectors was made available for trading in 2017, showing considerable room for improvement. Significant variations among capacity calculation regions (CCR) remain as shown in Figure i.

Figure i: Ratio of available tradable capacity to benchmark capacity on HVAC borders per CCR – 2017 (%)



Source: NRAs, Nord Pool Spot, ENTSO-E's CGM (2017) and ACER calculations (2018).

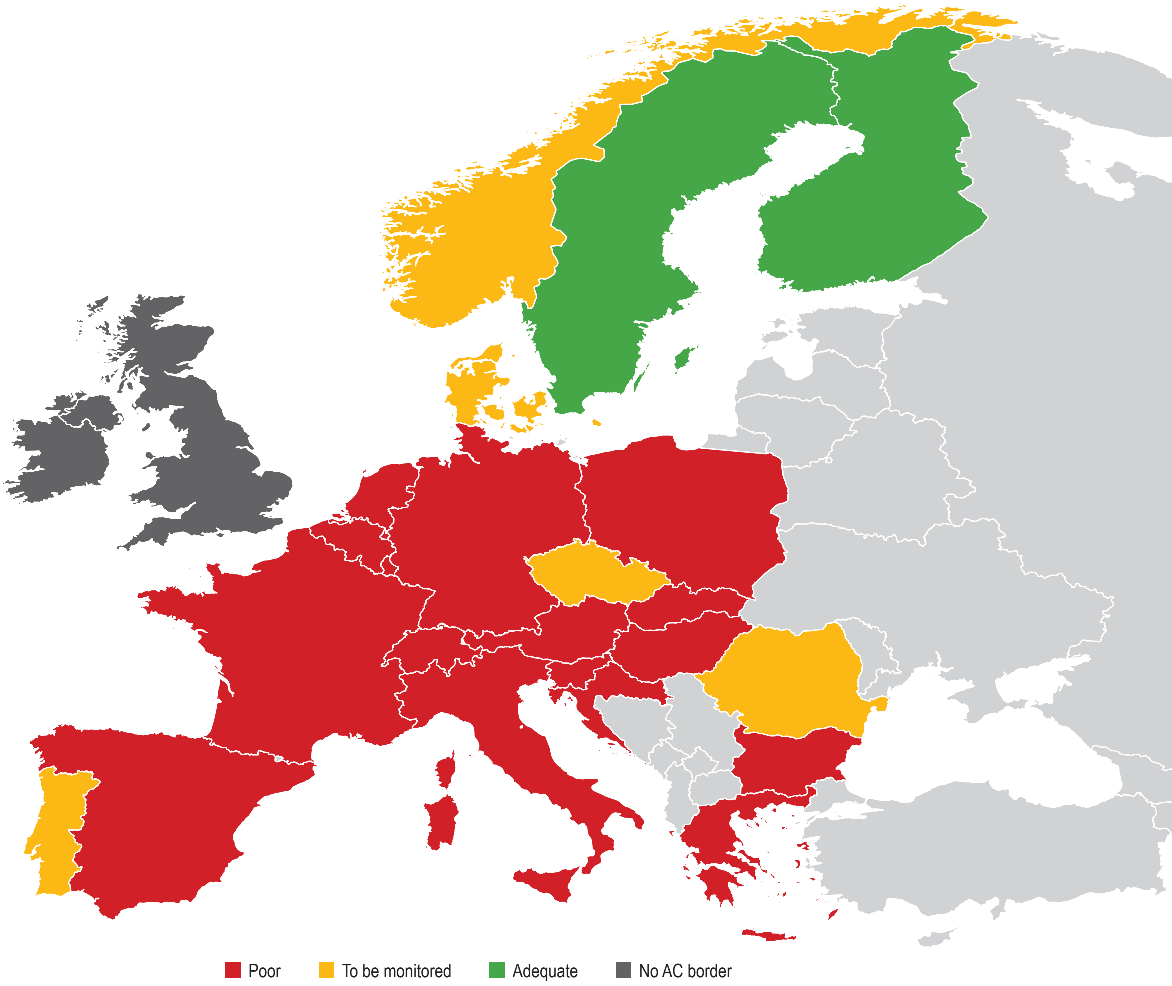
Note: CCRs where FB capacity calculation methodologies (CCMs) are currently applied or envisaged (based on TSOs' proposals) are shown in green, otherwise coordinated net transfer capacity (CNTC) methodologies are assumed and shown in blue. On borders where FBMC is applied or envisaged, values are compared to benchmark FB domains, whereas on other borders, average bidirectional NTC values are compared to benchmark NTCs. The following borders were excluded from the benchmark calculation: borders that do not belong to a CCR, and the Nordic and Baltic borders, because they were not part of the common grid model (CGM) data provided.

5 **The low cross-zonal capacities are probably the result of congestions not being properly addressed by the current bidding zone configuration in Europe,** as concluded in the 'market report'[2] on the efficiency of the current bidding zone configuration, which has been integrated as a section of this Volume of the MMR. The conclusion of this Report is based on the following indications.

6 First, **the relatively low level of available cross-zonal capacity, when compared to the Agency's benchmark, is in itself an indication that structural congestions may be located within bidding zones, rather than on bidding zone borders, in most of continental Europe.** Otherwise, the available capacity should be close to benchmark values. Figure ii provides a visual representation of how far countries are from the benchmark capacity on HVAC interconnectors. Countries connected to the rest of Europe with HVDC interconnectors only (i.e. United Kingdom and Ireland) are not analysed, although last year's MMR showed that these interconnectors perform considerably better than average.

2 Pursuant to Article 34(1) of the Capacity Allocation and Congestion Management (CACM) Regulation, the Agency has to produce such a report every three years.

Figure ii: National performance according to the level of cross-zonal capacity compared to benchmark capacity on HVAC interconnectors in Europe – 2015–2017



Source: NRAs, ENTSO-E and ACER calculations (2018).

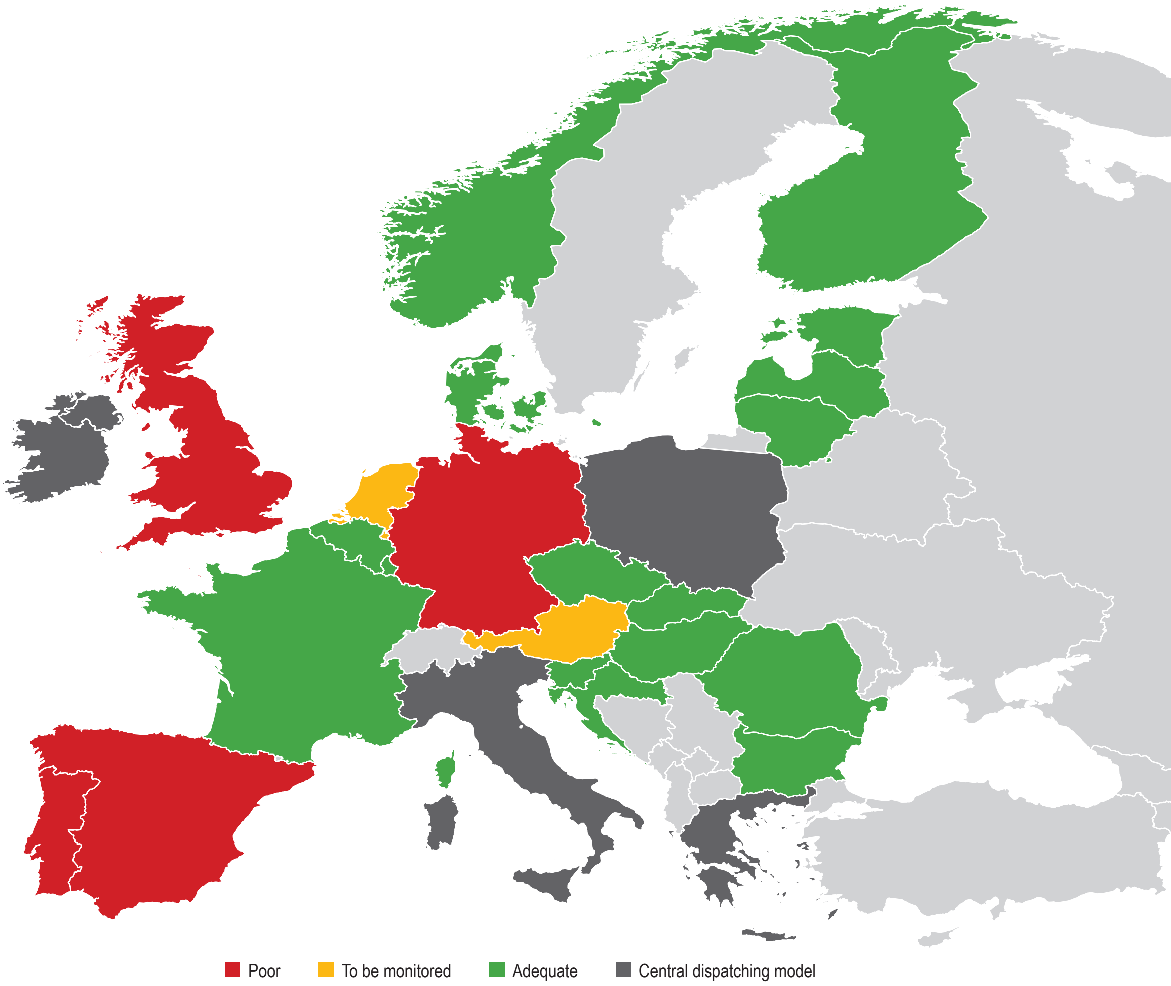
Note: Performance was assessed by comparing cross-zonal capacity made available for trading to benchmark capacity on HVAC borders in 2016, and by price convergence in the period 2015–2017. Poor performance for a given country corresponds to a situation where less than 75% of the average benchmark capacity on HVAC borders is provided to the market, and where average price spreads with neighbours are above 5 euros/MWh. Adequate performance for a given country corresponds to a situation where the average cross-zonal capacity amounts to at least 75% of the benchmark capacity, and average price spreads with neighbours are below 5 euros/MWh. Otherwise, performance is assessed as 'to be monitored'. For Finland, Norway and Sweden, a simplified assessment allows their cross-zonal capacities amount to be estimated at approximately 80% of the benchmark. Luxembourg is assumed to perform like Germany. The Italian performance is assessed for the Italy North border. Great Britain and Ireland (SEM) do not have AC borders, and are therefore depicted in dark grey. No information was available for Estonia, Latvia, and Lithuania, and these countries are depicted in grey.

7 Where sufficient information is available (e.g. in the CWE region), it confirms that **congestion most often relates to intra-zonal critical network elements (CNEs) rather than to interconnectors.** For example, when congestion occurred in the CWE region, internal lines constrained available capacity much more often (86% of occurrences[3]) than cross-zonal lines (14%) in 2017. More than half of these occurrences related to CNEs located inside Germany. Furthermore, this shows that CCMs often lack rules to avoid internal exchanges being unduly prioritised over cross-zonal ones.

3 The percentage represents the frequency of occurrence of congestions weighted with the relevant shadow prices, i.e. the welfare gains from relaxing the capacity constraint related to a CNE by 1 MW. Allocation constraints accounted for less than 1% of such weighted occurrences.

8 Second, these intra-zonal congestions require an intensive application of remedial actions by TSOs, which often come at a cost. **During the 2015–2017 period, the highest remedial actions costs were recorded in Spain, Germany, Portugal and Great Britain, with annual averages of 2.3, 1.7, 1.7 and 1.2 euros per MWh of demand, respectively.** Figure iii shows the relative performance of countries with respect to the use of costly remedial actions.

Figure iii: National performances with respect to the use of costly remedial actions – 2015–2017



Source: NRAs, ENTSO-E and ACER calculations (2018).

Note: Poor performance corresponds to the cost of remedial actions per unit of demand being above 1.0 euro/MWh; performance to be monitored corresponds to the cost of remedial actions per unit demand being between 0.2 and 1.0 euro/MWh, and adequate performance corresponds to the cost of remedial actions per unit demand being below 0.2 euros/MWh. As the central dispatching model is applied in Greece, Ireland, Italy, Northern Ireland and Poland, costs specifically linked to remedial actions are not available. As a result, these jurisdictions are depicted in dark grey. Sweden is depicted in grey, because no information on costly remedial actions was available.

9 Until a more efficient alternative bidding zone configuration is identified and applied, the capacity calculation process can mitigate the situation. First, **increased coordination among TSOs (e.g. by applying FB capacity calculation) contributes to alleviating the problem by significantly reducing so-called unscheduled allocated flows (UAFs).** These are flows allocated on a given border, but materialised (scheduled) on a different one; they tend to impede efficient cross-zonal exchanges, as those flows do not explicitly compete for capacity. In 2017, the lowest amount of UAFs was recorded in the CWE region, where FBMC is applied.

10 Second, efficient capacity calculation methodologies limit the extent to which internal exchanges are unduly prioritised over cross-zonal ones. **Currently, internal exchanges are disproportionally prioritised. For example, in 2017, the proportion of capacity made available for cross-zonal trade in CNEs in the CWE region was on average only 13% of their maximum capacity, whereas the remaining 87% was largely 'consumed' by flows resulting from internal exchanges.**

11 The unequal treatment of internal and cross-zonal exchanges can be addressed by applying the Agency's Recommendation on common capacity calculation and redispatching and countertrading cost-sharing methodologies[4]. **The gross benefits from implementing this Recommendation to the whole of Europe were estimated at more than 1 billion euros per year in 2017.** Although these estimates do not account for the costs incurred by TSOs in making this cross-zonal capacity available to the market, a simplified cost-benefit analysis conducted for small increases indicates that the benefits from enlarging cross-zonal capacity exceed the costs. A more detailed analysis should be conducted for larger increases.

12 Moreover, **additional benefits can be expected from enlarging the amount of available cross-zonal capacity in the long term.** This includes stronger incentives for the efficient reinforcement of the internal networks5, stronger incentives to coordinate both TSOs' action close-to-real-time and national energy policies and, finally, stronger incentives to consider the bidding zone reconfiguration as a crucial and possibly more efficient tool to foster market integration in the medium term.

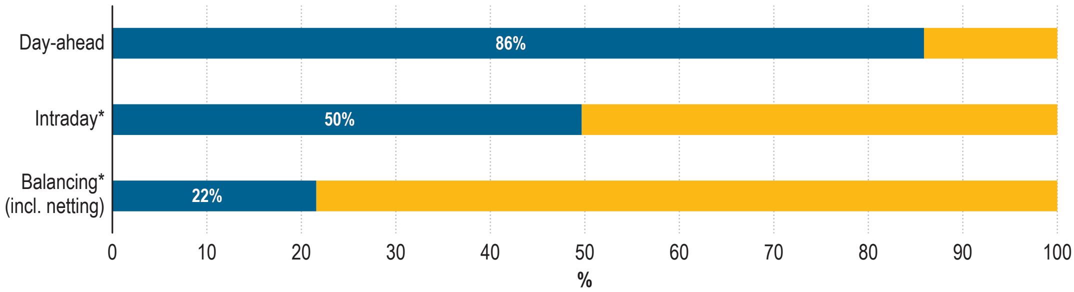
Efficient use of available cross-zonal capacity

13 **Thanks to the DA market coupling of two thirds of European borders, covering 22 European countries by the end of 2017, the level of efficiency in the use of interconnectors in this timeframe increased from approximately 60% in 2010 to 86% in 2017.**

14 As indicated in preceding MMRs, over the past seven years, market coupling has rendered a benefit of approximately 1 billion euros per year to European consumers. **The finalisation of market coupling implementation on all remaining European borders that still applied explicit DA auctions by the end of 2017 would render an additional social welfare benefit of more than 200 million euros per year.**

15 **As illustrated in Figure iv, compared to the DA timeframe, the level of efficient utilisation of cross-zonal capacity in the intraday (ID) timeframe remains low (50%),** which leaves a large part of the potential benefits from the use of existing infrastructure untapped across Europe.

Figure iv: Level of efficiency in the use of interconnectors in Europe in the different timeframes (% use of available commercial capacity in the 'right economic direction') – 2017



Source: ENTSO-E, NRAs, Vulcanus and ACER calculations (2018).

*Note: *Intraday and balancing values are based on a selection of EU borders.*

16 A crucial step towards the more efficient and sustainable use of available capacities across Europe was taken on 12 June 2018 with the go-live of the single intraday coupling (SIDC), one of the key elements of market design envisaged in the CACM Regulation[6]. The SIDC still needs to cover the whole of Europe and to be complemented with a system to price ID capacity, possibly via one or several ID pan-European auctions (as these have been proven to optimise the use of cross-zonal capacity). The additional welfare benefits from the more efficient use of ID cross-zonal capacity across Europe are estimated at more than 50 million euros per year.

4 Agency's Recommendation No 02/2016 of 11 November 2016 on the common capacity calculation and redispatching and countertrading cost-sharing methodologies, available at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf.

5 When this produces positive net benefits.

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

17 **In 2017, the projects to increase the exchange of balancing services across borders that were initiated in recent years started to bear fruit.** An example of these initiatives is the frequency containment reserves (FCR) cooperation, a common market for the procurement and exchange of balancing capacity, which currently involves ten TSOs in seven countries[7]. Over the past years, FCR capacity prices have been steadily decreasing and converging across the markets involved in the cooperation project.

18 Other initiatives aim to net imbalances or exchange balancing energy across TSOs' scheduling areas, such as the recently launched project to exchange energy from aFRR (automatically activated frequency restoration reserves) between Austrian and Germany. As a result, **the overall cross-zonal exchange of balancing energy (including imbalance netting) has almost doubled since 2015.**

19 **Despite these improvements, large disparities in balancing energy and balancing capacity prices persisted in Europe in 2017.** These disparities, together with a significant amount of unused cross-zonal capacity (see Figure iv), suggest considerable potential for further cross-zonal exchanges of balancing services in Europe. For example, the potential benefits from efficient imbalance netting and the exchange of balancing energy for the whole of Europe is as high as 1.3 billion euros annually. This confirms the importance of rapidly and effectively implementing the recently adopted Regulation establishing an Electricity Balancing Guideline.

Market liquidity

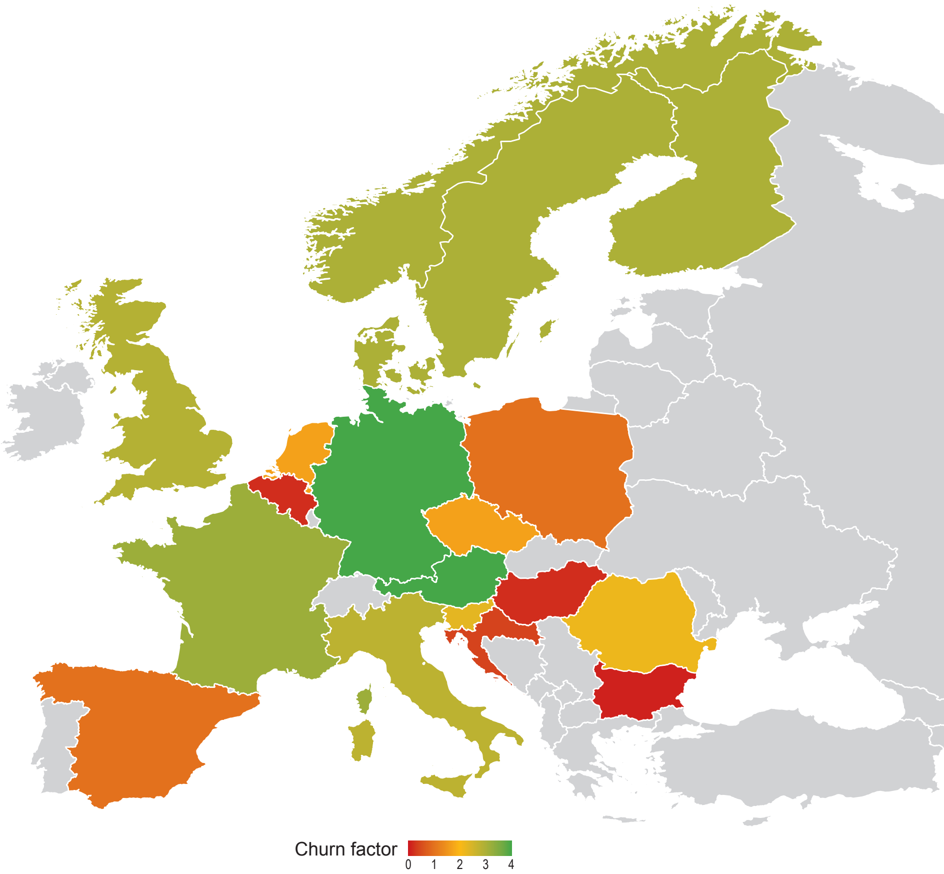
20 While DA markets are generally assessed to be liquid, there is still scope for improving the liquidity of forward and ID markets in Europe.

21 **The combined analysis of churn factors and bid-ask spreads confirms that forward markets liquidity in Europe remained modest or low in 2017, with the main exceptions being Germany/Austria/Luxembourg, followed by France, the Nordic region and Great Britain.**

22 Figure v suggests that **a direct correlation between the size of the bidding zones and forward markets liquidity cannot be established**. While the largest biggest bidding zone in Europe (Germany/Austria/Luxembourg) records the highest level of liquidity in forward markets, other large bidding zones (e.g. Spain or Poland) record low liquidity levels. Furthermore, in some geographical areas with relatively small bidding zones, e.g. in the Nordic area, the level of forward market liquidity is among the highest in Europe.

7 These are 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).

Figure v: Churn factors in main European forward markets – 2017



Source: European Power Trading 2018 report, © Prospex Research Ltd and NRAs (2018).

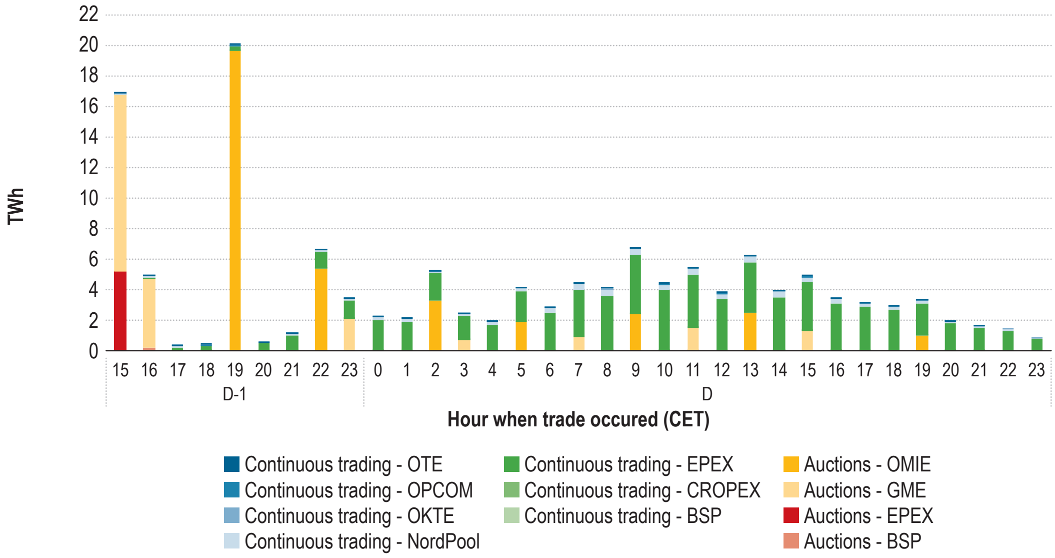
Note: For the purpose of calculating churn factors, the Nordic area is assessed as a single market, as its forward market relies mainly on a unique 'hub' price (the system price) used as a reference for all bidding zones in this area.

23 **As far as ID markets are concerned,** despite the fact that ID-traded volumes still account for a relatively small fraction of overall demand in most areas, **the upward trend in liquidity over the past years in most countries continued in 2017.**

24 The categorisation of ID-traded volumes according to trading time (day and hour when the trade occurred) displayed in Figure vi reveals that, in 2017, an important share of total ID-traded volume throughout Europe was concentrated around auctions on the day before delivery (D-1), while the volumes in continuous trading seemed to spread throughout the trading days D-1 and D. **A relatively late release of cross-zonal capacity for intraday trading would risk isolating national ID markets during trading hours with relatively high liquidity, e.g. more than one third of this liquidity would remain unshared across borders if the release of ID capacity were to take place on all borders at 22:00 on the day ahead of delivery,** as initially proposed e.g. by the TSOs of the Core region.

25 Although not explicitly shown in Figure vi, in markets with continuous trading, more than 50% of volumes were traded during the last trading hour in 2017, i.e. usually between 120 and 60 minutes before delivery. This illustrates that market participants value not only the early opening of ID markets, but also late closure, which enables close-to-real time trading.

Figure vi: Distribution of total ID-traded volumes for continuous trading and auctions per trading hour (CET), per trading method and per NEMO in Europe – 2017 (% volumes per hour when trade occurred on trading day D-1 and D)



Source: NEMOs and ACER calculations (2018).

Note: Hour n refers to the time between hour n and hour n+1.

Capacity mechanisms and adequacy assessments

26 **A patchwork of different and uncoordinated capacity mechanisms (CMs) remained throughout Europe in 2017.** The key change compared to 2016 relates to the submission for the European Commission's approval of six electricity CMs, adopting different structures, to ensure security of supply in Belgium, France, Germany, Greece, Italy and Poland. All of these CMs were approved in February 2018.

27 **The costs related to CMs amounted to more than 2 billion euros in Europe in 2017, and they are becoming a noticeable share of wholesale energy prices, e.g. in Ireland, where they accounted for 33% of average day-ahead wholesale energy prices in 2017 and, to a lesser extent in Greece (6%), France (5%) and Spain (3%).** These costs are expected to rise in the coming years, as the CMs approved or envisaged become operational, e.g. in Great Britain, where they are expected to account for approximately 4% of day-ahead wholesale energy prices in 2018.

28 As highlighted in previous MMRs, the starting point in the process of determining whether to implement a CM should be an assessment of the resource adequacy situation. Given the increasing interdependence of national electricity systems, a robust adequacy assessment needs properly to consider the contribution of interconnectors to adequacy, because such a contribution may be a crucial factor when deciding to implement a CM.

29 Regional or pan-European adequacy assessments such as the ENTSO-E mid-term adequacy forecasts (MAFs) have the potential to assess the contribution of interconnectors to adequacy more accurately and realistically than national generation adequacy assessments. In fact, **one third of national assessments, often used as a basis for the decision to implement a CM, persisted in ignoring the contribution of interconnectors**. Moreover, evidence (e.g. ex-post analysis as presented in last year's MMR) shows that most of the other two thirds of national generation adequacy assessments tend to significantly underestimate the contribution of interconnectors.

30 This purely national approach is all the more surprising in the context of the significant progress made towards a more integrated electricity market, and may lead to (or contribute to) a situation of overcapacity at the expense of end consumers. **Assessing and ensuring adequacy at pan-European level would yield annual benefits of approximately 3 billion euros[8].**

8 See e.g. https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf p. 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.

Recommendations

31 **Electricity markets are facing unprecedented challenges, which are emerging as they adapt to meet global decarbonisation targets, while safeguarding security of supply and ensuring affordability.** Moreover, the market integration process is at a tipping point due to the adoption and implementation of EU-wide rules. In this context, the timely and effective implementation of all the Regulations establishing Network Codes and Guidelines should remain an utmost priority. The Agency is strongly convinced that implementing the policy recommendations proposed in this Volume would also help to address both existing and emerging challenges, with the ultimate goal of ensuring a well-functioning internal electricity market.

32 **These recommendations are grouped into four distinct categories:**

1) **Recommendations on how to increase the limited amount of cross-zonal capacity made available for trading throughout Europe, without which any electricity market integration project is meaningless;**

2) **Recommendations on how to use the cross-zonal capacity made available for trading more efficiently in the different trading timeframes;**

3) **Recommendations on how to ensure market participants' sufficient and non-discriminatory access to forward and intraday markets; and**

4) **Recommendations on how to address adequacy concerns in an efficient manner.**

33 The first group of recommendations are 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 Europe. Among other things, this requires ensuring that congestions are efficiently addressed by the existing bidding zone configuration, the equal treatment of internal-to-bidding-zones and cross-zonal exchanges, increasing the level of TSOs' coordination, and improving the level of transparency of capacity calculation.

34 **In order to ensure that congestions are efficiently addressed, the Agency recommends that improvements to the existing bidding zone configuration be investigated with priority in the Core, Hansa and SWE CCRs**, because of the low cross-zonal capacities made available for trading and high costs of remedial actions. Investigations are also advisable in all other CCRs except the Nordic, Baltic and GRIT ones[9].

35 To facilitate these improvements, the bidding zone review envisaged in the CACM Regulation is the obvious approach. Bidding zone reviews should be neutral and unbiased, and should strive to focus only on technical and economic aspects. More specifically, bidding zone reviews should be conducted according to the following high-level principles. First, when considering alternative bidding zone configurations, a model-based approach should be used, and complemented by an expert-based approach. Second, the methodology should be clear and complete, and wide agreement on criteria (and their importance) should be sought before simulations are conducted. For example, a crucial aspect to be agreed on is the study time horizon and the inclusion of future network investments. In the Agency's view, the time horizon should be no longer than five years, and only network investments with certainty about their execution should be considered. Third, the process should be transparent, and should allow for regular regulators' and stakeholders' involvement throughout the study. Finally, as the legal framework supporting bidding zones reviews is currently under discussion[10], these reviews should start only when a more robust governance framework has entered into force.

36 Until such a framework is in place, the TSOs in each CCRs should consider the option of improving the bidding zone configuration directly, by identifying structural congestions, which, according to Regulation (EC) No 714/2009[11], must be addressed by capacity allocation mechanisms, thus resulting in a change of the bidding zones' configuration.

9 No relevant issues concerning the efficiency of the bidding zone configuration were found for these CCRs.

10 Within the "Clean Energy for All Europeans" legislative package discussions.

11 Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009, available at https://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF.

37 **In order to ensure the equal treatment of internal and cross-zonal exchanges, the Agency reiterates the importance of the high-level principles proposed in the Agency's Recommendation No 02/2016[12] being followed by TSOs and NRAs when developing, approving, implementing and monitoring capacity calculation methodologies.** Among other measures, the Recommendation envisages the application of remedial actions (e.g. redispatching) to preserve cross-border exchanges.

38 In order to improve the level of TSO coordination, the following is recommended:

a) **NRAs and TSOs should ensure the effective, efficient and rapid implementation of all legal provisions related to TSO coordination** (for instance, as introduced by the Regulation establishing a System Operation Guideline[13] for regional security centres or potentially for regional operation centres in the future[14]).

b) **NRAs and TSOs should ensure the smooth, effective and rapid implementation of FB capacity calculation** where relevant, as required by the CACM Regulation.

39 **In order to increase the transparency of capacity calculation, the following is recommended:**

a) **NRAs should request from TSOs the regular publication of all data generated for cross-zonal capacity calculation in a timely and user-friendly manner.**

b) **The European legislators should provide the Agency with stronger data collection powers in order to fulfil its monitoring tasks.**

40 The second group of recommendations is aimed at ensuring that the cross-zonal capacity made available for trading is used efficiently in the different market timeframes. For this, the Agency recommends the following:

a) **NRAs and TSOs should finalise the implementation of single day-ahead coupling (SDAC) and SIDC.**

b) When developing and approving a cross-zonal ID capacity pricing methodology[15], **NRAs should take into account that ID auctions are not only a possible tool to price capacity, but also a way to increase the level of efficient interconnector use in the ID timeframe.**

c) **TSOs should jointly optimise the procurement of balancing capacity, and optimise the exchange of balancing resources,** as the largest part of the potential benefits from integrating balancing markets remains untapped across Europe

d) In general, **the full, effective and rapid implementation of the Regulation establishing an Electricity Balancing Guideline is needed.**

41 The third group of recommendations is aimed supporting and fostering forward and intraday markets liquidity and at ensuring non-discriminatory access to these markets.

42 **With regard to forward markets, solutions that decouple liquidity from the size of the bidding zones, e.g. relying on multi-bidding-zones hedging instruments[16], would enable the equal access of market participants to hedging opportunities irrespective of their geographical location.**

12 See footnote 4.

13 See the provisional final version of the System Operation Guideline at https://ec.europa.eu/energy/sites/ener/files/documents/SystemOperationGuideline%20final%28provisional%2904052016.pdf.

14 See more in the EC's 'Clean Energy for All Europeans' legislative proposal, which is available at: https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition.

15 On 14 August 2017, an all TSOs' common proposal for a single methodology for pricing intraday cross-zonal capacity was submitted to all NRAs. On 23 July 2018, all NRAs, after agreeing on a general view on the IDCZCP proposal, have agreed to request that the Agency adopts a decision on IDCZCP pursuant to 9(12) of the CACM Regulation.

16 Other options, such as issuing zone-to-zone financial transmission rights may be explored.

43 With regard to intraday markets, the following is recommended:

a) **NRAs and TSOs should ensure full balancing responsibility for all technologies[17] and should enforce cost-reflective balancing charges.**

b) **TSOs should release ID cross-zonal capacity as early as possible** in order to limit the isolation of zonal ID markets during trading hours with relatively high liquidity;

c) **When approving and developing a pan-European ID system to price ID capacity, setting the timing of such a system should take into consideration the points in time when liquidity is already high,** because higher liquidity should contribute to the more efficient pricing of capacity.

44 The fourth group of recommendations is intended to address adequacy concerns in an efficient manner. In this field, the Agency recommends the following:

a) **Before implementing a CM, MSs should exhaust all possible measures to eliminate distortions contributing to the identified resource adequacy concern.** These measures include removing price caps (or setting them at levels that reflect the value of lost load), ensuring the equal treatment of generation technologies regarding balance responsibilities, increasing demand-side participation, removing undue limitations on cross-zonal trade, and removing any other barrier to efficient price formation in wholesale electricity markets.

b) **MSs, the Commission and NRAs should seek ways to strengthen the role of European adequacy assessments.** In particular, the estimated contribution of interconnectors when considering the implementation of a CM should be based on regional or pan-European assessments, as they have clear potential to provide more efficient results than fragmented national assessments.

17 Except temporary exemptions for justified purposes, such as pilot projects for the purpose of research and development.

1. Introduction

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

46 The goal of the Electricity Wholesale Markets Volume is to present the results of the monitoring of the performance of the internal electricity market in the European Union[18] (EU), which depends on how efficiently the European electricity network is used and on the performance of electricity wholesale markets in all timeframes. When electricity wholesale markets are integrated via sufficient interconnector capacity, then competition will benefit all consumers, improve energy system adequacy and ensure security of supply in the long term.

47 The Regulation establishing a Guideline on Capacity Allocation and Congestion Management (CACM)[19] that is currently being implemented provides clear objectives to deliver an integrated internal electricity market 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.

48 These processes are intended to optimise the utilisation of the existing infrastructure and to provide the market with 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 existing network. A crucial step towards a more efficient and sustainable use of available capacities across Europe was taken on 12 June 2018 with the go-live of the Single Intraday Coupling (SIDC), one of the key elements of market design envisaged in the CACM Regulation.

49 The Regulations establishing Guidelines on Forward Capacity Allocation (FCA)[20] and on Electricity Balancing (EB)[21] will also play a crucial role in the further integration of the Internal Energy Market (IEM). The former establishes a framework for the calculation and efficient allocation of interconnection capacity, and for cross-zonal trading in forward markets, while the latter sets rules on the operation of balancing markets, i.e. those markets that TSOs use to procure energy and capacity to keep the system in balance in real time. Moreover, it aims to increase the opportunities for cross-zonal trading and the efficiency of balancing markets.

50 With the ongoing implementation of the provisions included in the above-mentioned Guidelines, the electricity markets integration process is currently at its critical point. The implementation of those provisions remains a key priority for the Agency for the Cooperation of Energy Regulators ('the Agency' or 'ACER').

51 Moreover, this Volume should be read in the context of the ongoing discussions regarding the European Commission's (EC) Clean Energy for All Europeans[22] legislative proposal on new rules for a consumer-centred clean energy transition[23].

18 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'. Several maps included in this report show Kosovo*. In this context, throughout this document, the asterisk symbol refers to the following statement: "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".

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

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

21 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.

22 The Commission's Clean Energy for All Europeans legislative proposal covers energy efficiency, RES generation, the design of the electricity market, security of electricity supply and governance rules for the Energy Union, and is available at: https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition.

23 For example, in June 2018, European energy regulators expressed concerns on some provisions related to cross-zonal capacity calculation in this legislative proposal, The issue of cross-zonal capacity calculation is extensively assessed in Chapter 3 of this Volume.

52 The Electricity Wholesale Markets Volume is organised as follows. Chapter 2 presents the key developments in electricity wholesale markets across Europe in 2017. Chapter 3 assesses the level of cross-zonal capacities made available for trade and the performance of the capacity calculation processes, with a focus on the comparative treatment of internal as opposed to cross-zonal exchanges. Moreover, Chapter 3 includes, as section 3.4, a report on the efficiency of the bidding zone configuration. This report constitutes the Agency's market report evaluating the impact of the current bidding zone configuration on market efficiency, in accordance with Article 34(1) of the CACM Regulation. Chapter 4 assesses market liquidity with a focus on forward and ID markets. The performance of forward, DA, ID and balancing markets, and particularly the use of cross-zonal capacity across these timeframes, is presented in Chapter 5. The volume ends with a presentation of the situation of Capacity Mechanisms (CMs) and of the treatment of interconnectors in the national adequacy assessments in Chapter 6.

53 Finally, 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'[24], which are cross-referenced in the relevant chapters where those methodologies are applied.

24 These methodological papers are available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Methodologies.aspx.

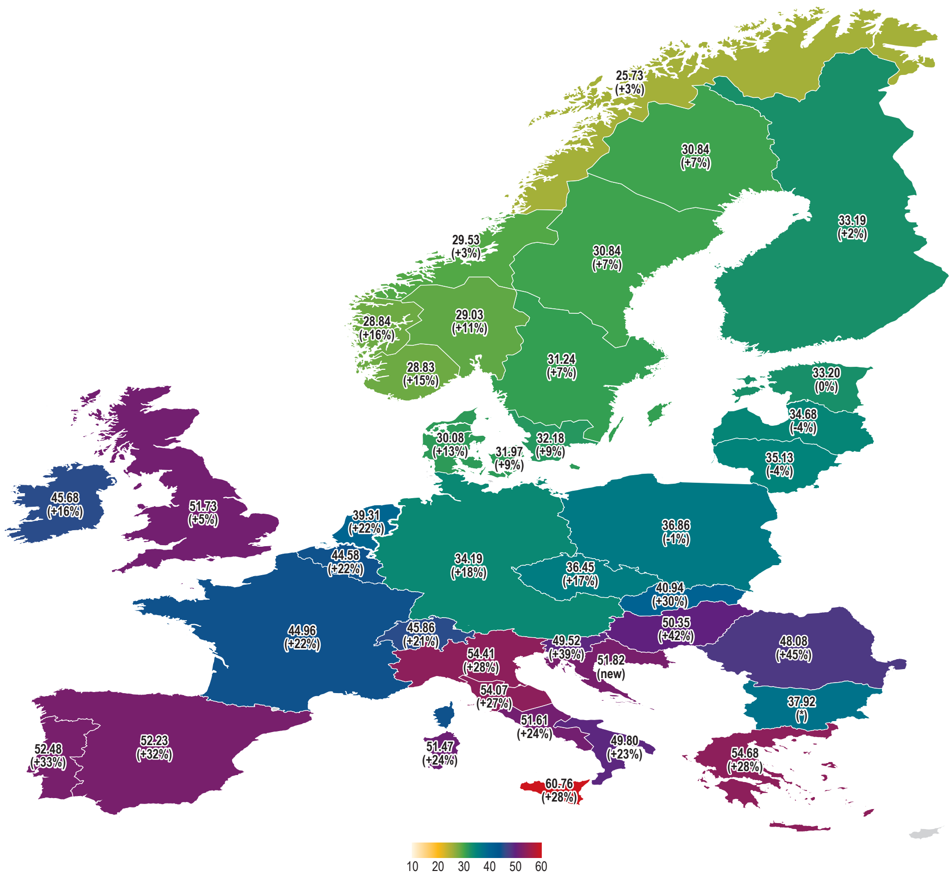
2. Key developments in 2017

54 This Chapter reports on the evolution of prices in European electricity wholesale markets in 2017 (Section 2.1) and the level of price convergence within European market coupling regions (Section 2.2).

2.1 Evolution of prices

55 Figure 1 shows the average annual DA electricity prices in 2017 in all European bidding zones, as well as the relative price change compared to 2016. In 2017, average DA electricity prices increased in all bidding zones, except in the Baltic and Polish markets. In 2017, the highest annual average DA prices were observed in the Greek, Iberian, Italian and British markets.

Figure 1: Average annual DA electricity prices and relative changes compared to the previous year in European bidding zones – 2017 (euros/MWh and % change compared to 2016)



Source: Transparency Platform (TP) of the European Network of Transmission System Operators for Electricity (ENTSO-E) and ACER calculations (2018).

*Note: The data set with DA prices for Bulgaria and Poland was incomplete on the TP. *For Bulgaria, 90% and 7% of the hours in 2016 and 2017, respectively, were missing. For Poland, 19% and 2% of the hours in 2016 and 2017, respectively, were missing.*

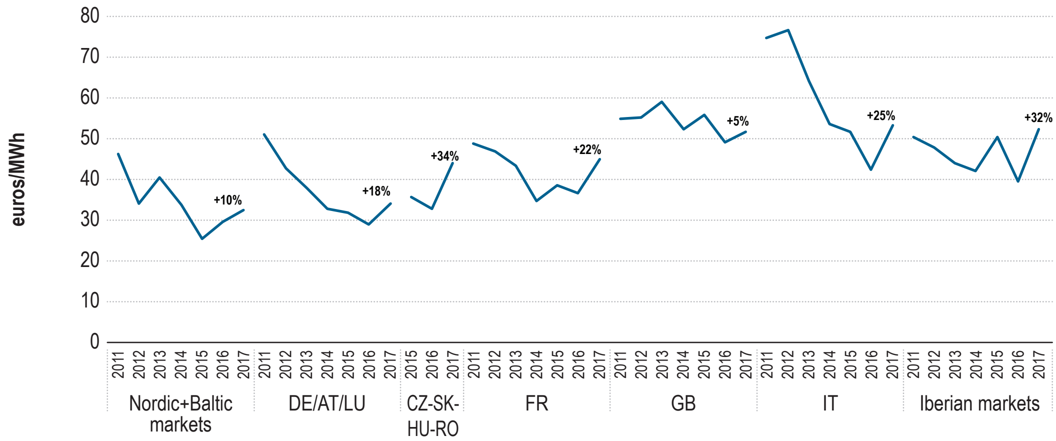
56 On the demand side of the market, the main explanatory factor for the overall increase in DA prices in 2017 is economic growth. In 2017, the EU's gross domestic product[25] (GDP) grew by 2.5% compared to the previous year, which is the highest annual growth rate in the past decade since the financial and economic crisis.

25 In the absence of electricity demand data in 2017 (see also footnote 108), the EU's GDP developments provide an indication of electricity demand trends. For more information on GDP growth rates, see: http://ec.europa.eu/eurostat/documents/2995521/8627394/2-30012018-AP-EN.pdf/0374d17b-ba86-4aab-8837-c4865e087ceb.

57 On the supply side of the market, prices are mainly explained by changes in the European generation mix[26] and in fuel prices between 2016 and 2017. Generation technologies with relatively low variable costs[27], such as hydro (-19%) and nuclear power (-15%) were partly replaced by more expensive fossil fuel-based technologies. In particular, the share of electricity generated by gas-fired power plants increased by 4% compared to the previous year, reaching its highest level in seven years. As regards fuel prices, both gas and coal prices increased significantly[28] between 2016 and 2017.

58 Figure 2 shows, for a selection of large European markets, that the upward evolution of prices between 2016 and 2017 is a reverse trend, compared to previous years. In 2017, the highest price increases among the analysed markets were recorded in the area comprising the Czech Republic, Slovakia, Hungary and Romania, commonly referred to as the 4M Market Coupling (4MMC)[29], followed by the Iberian and Italian markets, with an overall price increase of 34%, 32% and 25%, respectively, compared to 2016.

Figure 2: Evolution of annual DA electricity prices in a selection of European markets – 2011–2017 (euros/MWh)



Source: ENTSO-E (2018).

59 In addition to the general price drivers described in paragraphs 56 and 57, these price increases are explained by the following regional-specific drivers.

60 In the 4MMC market, the price increase between 2016 and 2017 is mainly explained by the limited availability of various generation technologies at times of relatively high demand[30] putting upward pressure on prices, e.g. limited coal generation due to frozen lignite stocks and frozen rivers in Hungary during the cold spell in January 2017, or lack of nuclear generation due to unplanned outages in Romania during the heat wave in August 2017.

26 The figures on the evolution of the generation mix are based on Eurostat data and the relative change in 2017 compared to 2016 recorded by ENTSO-E in its equivalent monthly generation categories.

27 Low hydro availability throughout Europe was caused by low reservoir levels in the absence of rain in 2016 and 2017. Low nuclear generation throughout Europe was mainly caused by low availability in Belgium (maintenance), France (safety tests) and Germany (maintenance).

28 In 2017, average DA natural gas prices in the Title Transfer Facility (TTF) gas hub were 24% higher, compared to 2016. For more information on developments in the European gas markets, see chapter 2.2 Price developments of the Gas Wholesale Markets Volume of this MMR, which is available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202017%20-%20Gas%20Wholesale%20Markets%20Volume.pdf. Similarly, in 2017, average annual OPEC crude oil prices were 29% higher compared to 2016. In 2017, average annual coal prices (CIF ARA 6000 kcal/kg) increased by 38% compared to the previous year.

29 4MMC refers to DA market coupling in the Czech Republic, Slovakia, Hungary and Romania, which was implemented on 19 November 2014 based on the Price Coupling of Regions (PCR) solution. The objective of the 4MMC is to be coupled with the Multi-Regional Coupling (MRC) region in order to form the pan-European Single Day-Ahead Coupling (SDAC), which covers for the time being the following 19 MSs: Austria, Belgium, Germany, Denmark, Estonia, Finland, France, Great Britain, Italy, Lithuania, Latvia, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia and Sweden.

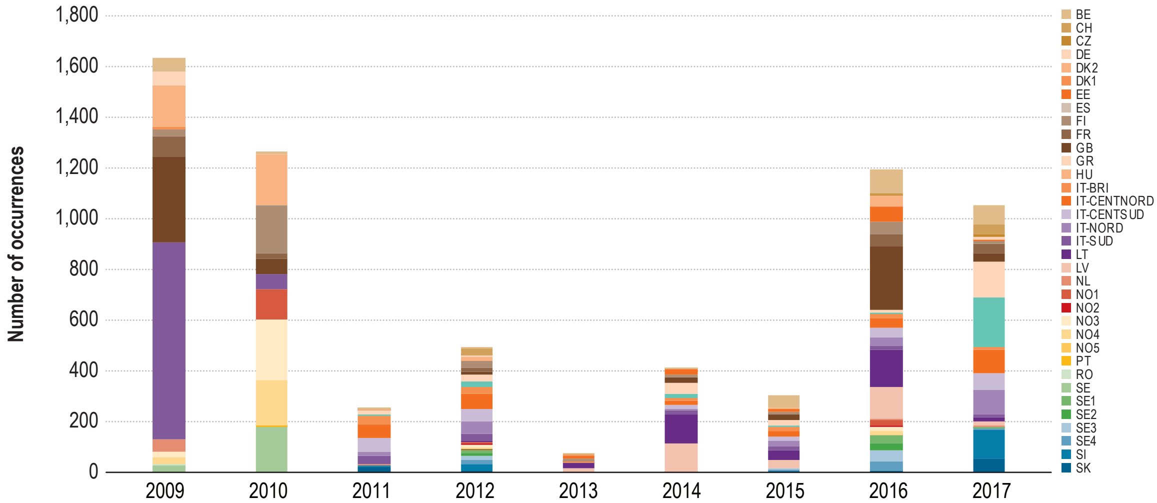
30 For example, the monthly electricity demand was 11%, 9%, 6% and 2% higher in January 2017, compared to January 2016 in the Czech Republic, Hungary, Slovakia and Romania, respectively (based on the monthly net electricity generation, provided by Eurostat).

61 In the Iberian market, the price increase in 2017 is mainly explained by the decrease in generation from hydro power (-51%) compared to 2016, which led to more fossil fuels in the generation mix (+21% and +19% for coal and natural gas respectively). The shift from coal to gas, following an increase in coal prices, and a cold spell in January 2017[31] put additional upward pressure on domestic generation costs.

62 In Italy, the upward price developments in 2017 are partially explained by fewer imports from France due to high DA prices there, which were caused by reduced nuclear availability, higher temperature-driven demand (caused by the cold spell in January 2017 and higher-than-usual temperatures between May and August 2017), as well as a shift in the generation mix. Compared to 2016, in 2017, Italy recorded an increase in the utilisation of natural gas and solar power by 15% and 14%, respectively, while generation from coal (fossil hard coal) and hydro decreased by 17% and 15%, respectively.

63 Consistent with the trend of rising prices, Figure 3 shows that the reappearance of price spikes[32] in 2016 (1,195 price spike occurrences) continued in 2017, with 1,051 price spike occurrences. The reoccurrence of price spikes observed in the past two years constitutes a significant change when compared to the 2011–2015 period. In 2017, price spikes occurred most notably in Hungary (195 occurrences), Greece (140 occurrences) and Slovenia (118 occurrences), where 50% of all these spikes occurred in January 2017 during the cold spell. The remaining 50% of these price spikes occurred sporadically throughout the year, with a large concentration during the heat wave in August 2017 in Hungary and Slovenia, but also in November 2017 in Greece.

Figure 3: Frequency of price spikes in the main wholesale DA markets in Europe – 2009–2017 (number of occurrences)



Source: ENTSO-E and ACER calculations (2018).

31 Following the high DA prices recorded in January 2017 during the cold spell, triggering an increase in retail prices, the Spanish NRA opened an investigation into the underlying reasons for the successive increases in retail electricity prices in recent years.

32 Consistently with the previous edition of the MMR, a price spike is defined as an hourly DA price, which 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 (p. 9) of the Electricity Wholesale Markets Volume of the MMR 2015, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf.

64 During the cold spell of January 2017, exceptional measures limiting cross-border exports in several Member States (MSs) put upward pressure on prices. Cross-border capacity was curtailed most notably from France[33] to Spain during peak hours between 14–20 January 2017, from Greece[34] to Italy and Bulgaria between 11–12 January 2017, and from Italy[35] to France, Slovenia and Austria during some hours between 18–19 January 2017. Moreover, the measures taken in Bulgaria[36] resulted in the suspension of cross-border capacity allocation for exports between 13 January–9 February 2017. Romania[37] also introduced the possibility of limiting exports, but did not apply them. Nevertheless, it is important to highlight that some of these curtailments appear to be justified and had no significant impact on cross-zonal electricity flows, while others seem to be questionable[38].

65 The reappearance of price spikes throughout Europe illustrates two key aspects of the electricity market design. On the one hand, it illustrates the potential of energy-only markets to allow generators to cover their fixed costs. On the other hand, the fact that during the reappearance of price spikes several MSs took unilateral decisions to limit electricity exports, although these type of restrictions are not allowed under current legislation[39], emphasises the need to address adequacy issues in a highly coordinated and market-based manner (see Section 6.2). Whereas MSs have a legitimate interest in ensuring security of supply in their countries at all times, unilateral or uncoordinated actions endanger security of supply in the region and hamper the well-functioning of the internal electricity market.

2.2 Price convergence

66 The price convergence in DA markets provides an indication of the level of electricity market integration. For instance, price convergence is expected to increase following the introduction of market coupling, the expansion of the existing infrastructure, or following an increase in the amount of commercial cross-zonal capacity. As year-on-year changes may also be caused by market fundamentals which are not necessarily related to the level of market integration, price convergence should be analysed over longer periods, i.e. more than one year. However, reaching full price convergence is not an objective as such, because it would require overinvestment in interconnectors.

67 Figure 4 provides an overview of the degree of price convergence within European market coupling regions[40] between 2008 and 2017. It shows that increases in the frequency of full price convergence between 2016 and 2017 were observed in the Baltic and CWE regions, which also correspond to the Capacity Calculation Regions (CCRs) with the highest number of hours with full price convergence observed in 2017.

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33 See, for example, the message published by the Joint Allocation Office (JAO) on 13 January 2017, available at: http://www.jao.eu/news/messageboard/view?parameters=%7B%22NewsId%22%3A%22e45d0631-adde-4053-a002-a6fa012819ed%22%2C%22FromMoreJAO%22%3A%221%22%7D.

34 For more information, see the study on ‘EU Electricity Markets in January and February 2017’ by S&P Global Platts, available at: https://ec.europa.eu/energy/sites/ener/files/documents/platts_report_final_version_rrr.pdf.

35 See, for example, the message published by the JAO on 17 January 2017, available at: http://www.jao.eu/news/messageboard/view?parameters=%7B%22NewsId%22%3A%22813ae083-a961-4294-b256-a6fe008db31f%22%2C%22FromMoreJAO%22%3A%221%22%7D.

36 Order 16-64 of 11 January 2017 issued by the Minister of Energy of Bulgaria.

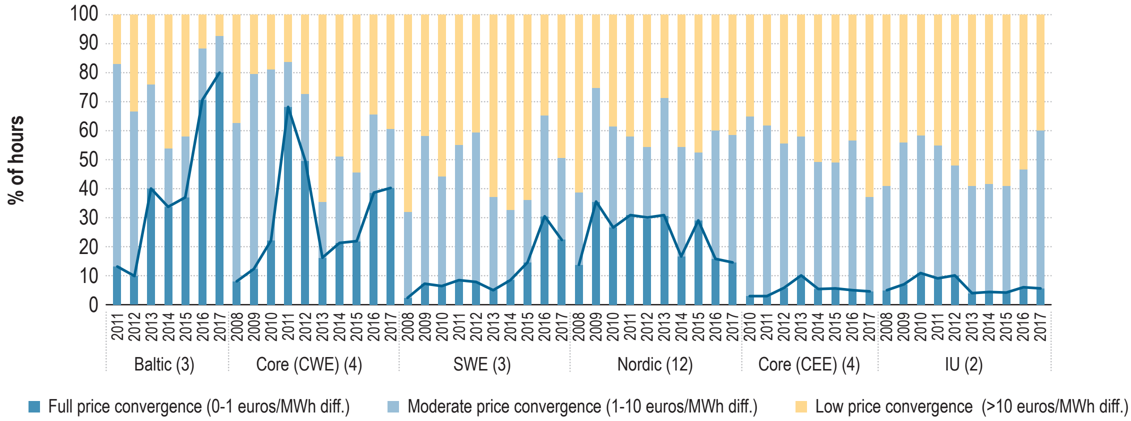
37 Government Decision No 10/2017 regarding the adoption of safety measures in the Romanian electricity market.

38 For more information, see study on ‘EU Electricity in January and February 2017’ by S&P Global Platts (see footnote 34) and the Quarterly Report on European Electricity Markets by DG Energy of the European Commission, available at: https://ec.europa.eu/energy/sites/ener/files/documents/quarterly_report_on_european_electricity_markets_q1_2017.pdf.

39 For example, the CACM Regulation stipulates that: “TSOs should […] avoid unnecessary curtailments of cross-border capacities”. Moreover, according to Article 72 of the CACM Regulation “in all cases, curtailment shall be undertaken in a coordinated manner following liaison with all directly concerned TSOs”. Similarly, Article 16 of Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity stipulates: “Transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and re-dispatching or countertrading is not possible. Any such procedure shall be applied in a non-discriminatory manner.”

40 For the purpose of this analysis and throughout this report, bidding zones are grouped into regions, in line with Agency Decision No 06/2016 of 17 November 2016 on the TSOs’ proposal for the determination of CCRs, except for Central-West Europe (CWE) and Central-East Europe (CEE) regions, which are identified throughout this document as the Core (CWE) or CWE region and the Core (CEE) region, for consistency and comparability with the results presented in previous MMRs. Agency Decision No 06/2016 is available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2006-2016%20on%20CCR.pdf.

Figure 4: DA price convergence in Europe by CCR (ranked) – 2008–2017 (% of hours)

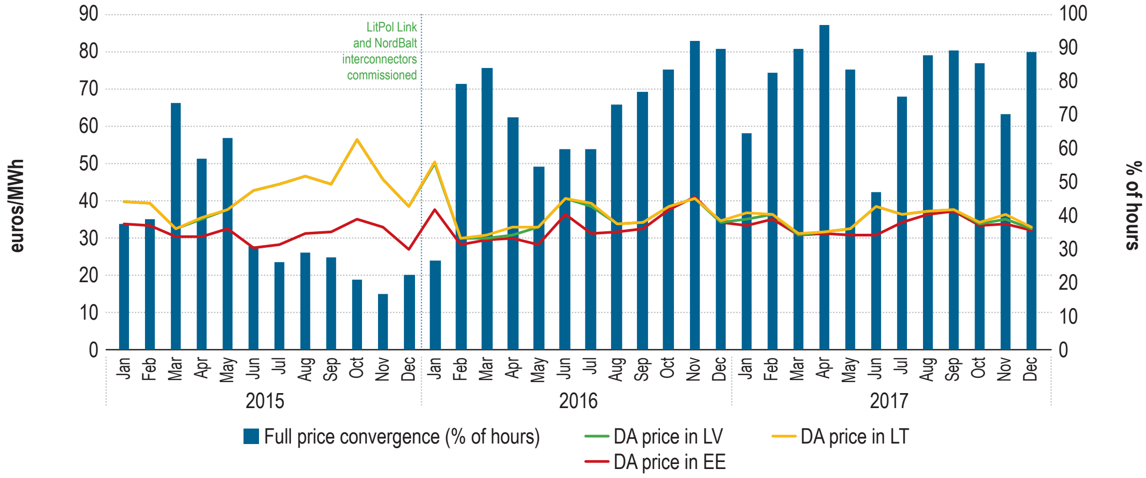


Source: ENTSO-E and ACER calculations (2018).

Note: The numbers in brackets refer to the number of bidding zones included in the analysis per CCR.

68 Figure 5 shows that the Baltic region recorded full price convergence during 80% of the hours in 2017. This is mainly explained by the increase in the amount of cross-border capacity within the Baltic region, as well as between the Baltic and neighbouring regions, following the commissioning of the LitPol Link (Lithuania-Poland) and the NordBalt (Lithuania-Sweden) interconnectors on 9 and 14 December 2015, respectively.

Figure 5: Monthly DA prices and frequency of full price convergence in the Baltic region – 2015–2017 (euros/MWh and % of hours)

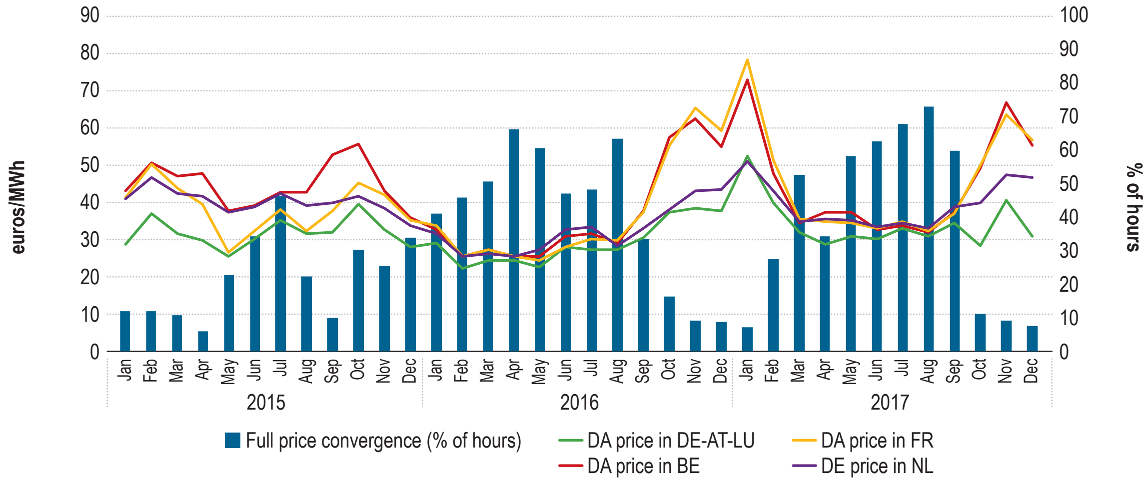


Source: ENTSO-E and ACER calculations (2018).

69 In the CWE region, full price convergence occurred during 41% of the hours of 2017. Nevertheless, large discrepancies are observed between quarters, as illustrated in Figure 6. During the first and last quarter of 2017, relatively low price convergence and large price differentials were observed, mainly due to a prolonged period of low nuclear availability in France and, to a lesser extent, due to low nuclear availability in the first quarter in Belgium and Germany[41]. The second and the third quarters of 2017 recorded full price convergence more frequently, partly due to higher nuclear availability in these countries. Despite the scope for increasing the amount of cross-zonal capacity within this region (see Sub-sections 3.1.2 and 3.2.2), the increase in price convergence observed during the last two years can be partly attributed to the implementation of Flow-Based Market Coupling (FBMC) in the CWE region in 2015.

41 In France, in October and November 2017, significant nuclear capacities were taken offline again due to extended planned maintenance works and unplanned shutdowns due to safety inspections ordered by the French nuclear safety authority (safety inspections, starting in 2016, had previously reduced nuclear generation capacities in France). In Belgium, nuclear reactors were taken offline in the first quarter for maintenance works and repairs on non-nuclear infrastructure. In Germany, maintenance works and the exceptional winter (2016/2017) refuelling cycle – usually done in the summer months – of four out of eight nuclear reactors, related to the expiry of the nuclear fuel tax on 31 December 2016, reduced the availability of nuclear capacity significantly in the first quarter of 2017.

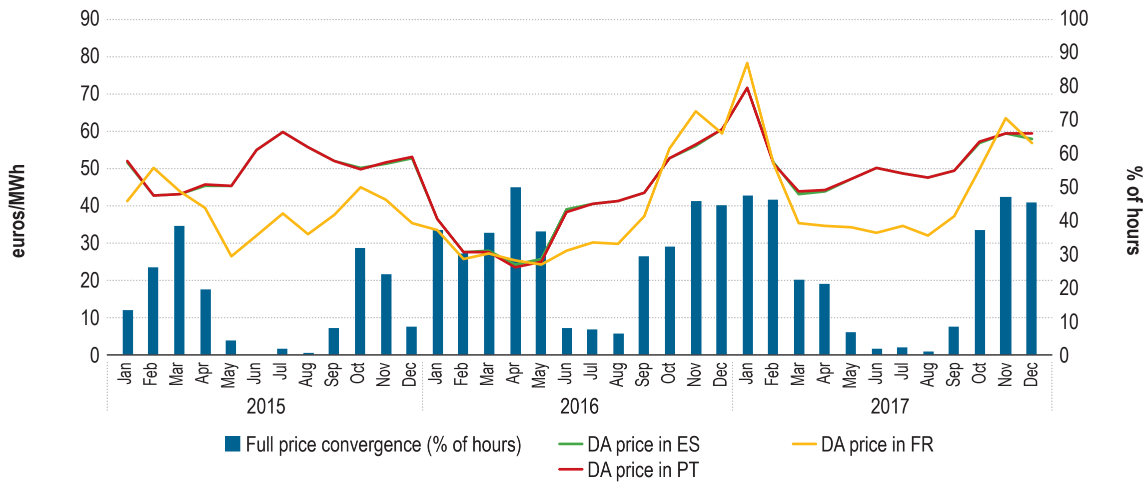
Figure 6: Monthly DA prices and frequency of full price convergence in the CWE region – 2015–2017 (euros/MWh and % of hours)



Source: ENTSO-E and ACER calculations (2018).

70 In the remaining analysed regions, the occurrence of full price convergence decreased in 2017 compared to 2016. Most notably, full price convergence deteriorated by 27% in South-West Europe (SWE) region, as shown in Figure 7. In particular, during the second and third quarters of 2017, the average price differential between Spain and France was very high (13.1 euros/MWh), whereas Spanish and Portuguese DA prices fully converged 95% of the time. The price differential between the Iberian peninsula and France is explained by the price increases in Spain and Portugal in 2017. Prices in these two MSs reached their highest levels in eight years due to a significant shift in the mix of domestic electricity generation in 2017 (see paragraph 61).

Figure 7: Monthly DA prices and frequency of full price convergence in the SWE region – 2015–2017 (euros/MWh and % of hours)



Source: ENTSO-E and ACER calculations (2018).

71 In conclusion, there is still scope for price convergence in Europe. This is also illustrated by the divergent levels of price spreads across European bidding zone borders in Table 5 in Annex 1. Moreover, the analysis on price convergence, interpreted together with the conclusions of the analysis presented in Chapter 3 on available cross-zonal capacity, emphasises the importance of maximising the amount of tradable cross-zonal capacity, particularly on the bidding zone borders with the highest price spreads.

3. Available cross-zonal capacity

72 The optimisation in the provision of cross-zonal capacity is an essential prerequisite for a well-integrated and efficient IEM. This Chapter first provides an overview of the levels of tradable[42] (i.e. available for trade) cross-zonal capacity in Europe, including the relation between these levels and the physical capacity of interconnectors (Section 3.1). Then, it assesses the reasons for the large gap between physical and tradable capacity on most European borders, and provides recommendations on how to reduce this gap (Section 3.2). Third, it assesses the use of remedial actions (Section 3.3), and finally it includes a report on the efficiency of the bidding zone configuration (Section 3.4). This report constitutes the Agency's market report evaluating the impact of the current bidding zone configuration on market efficiency, in accordance with Article 34(1) of the CACM Regulation.

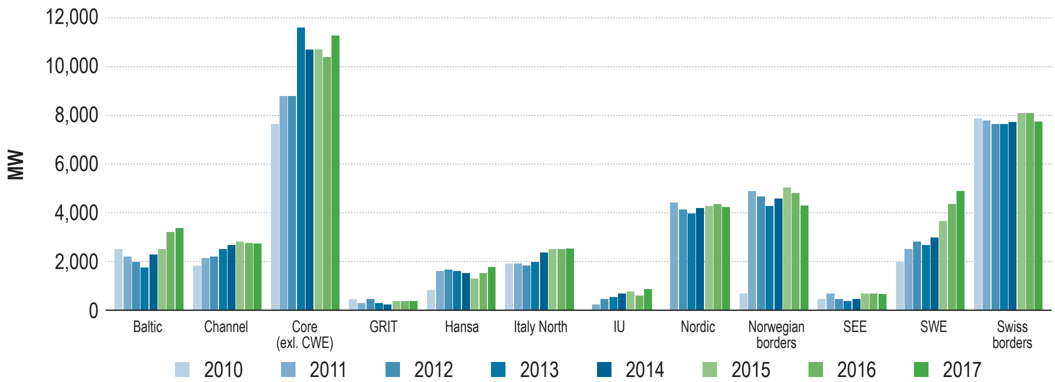
3.1 Amount of cross-zonal capacity made available to the market

73 First, this Section assesses the amount of cross-zonal capacity made available to the market in 2017 compared to 2016 (Sub-section 3.1.1). Second, it compares actual cross-zonal capacity with a benchmark (i.e. maximum feasible) cross-zonal capacity (Sub-section 3.1.2).

3.1.1 Evolution of commercial cross-zonal capacity

74 Figure 8 presents average cross-zonal Net Transfer Capacity (NTC) values aggregated per CCR[43] from 2010 to 2017. The overall level of tradable capacities slightly increased in 2017 compared to 2016 (+2.4%). The highest increases occurred in the Core (excluding CWE) and SWE regions, followed by the Baltic and Hansa regions. Decreases mainly occurred on the borders with Norway and Switzerland.

Figure 8: NTC averages of both directions on cross-zonal borders, aggregated per CCR – 2010–2017 (MW)



Source: ENTSO-E, National Regulatory Authorities (NRAs), Nord Pool and ACER calculations (2018).
Note: Only cross-zonal NTC and technical profiles values are considered in this Figure.

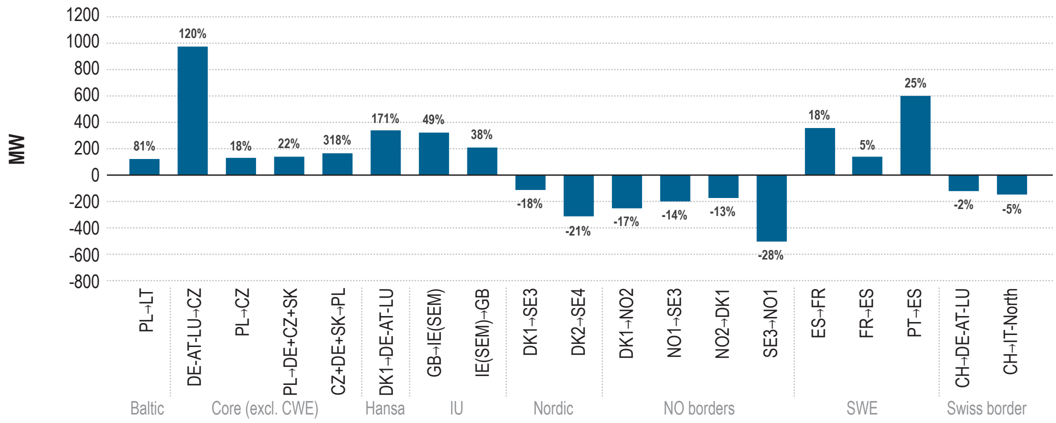
42 Throughout this Volume, tradable cross-zonal capacity is also referred to as commercial cross-zonal capacity, available cross-zonal capacity or, simply, commercial or available capacity.

43 The Core (CWE) region is not included, as FBMC has been applied there since 2015 (see Figure 10 for Core (CWE) data). Average NTCs are displayed for Norwegian and Swiss borders.

75 Figure 9 shows the major changes in NTCs on selected European borders between 2016 and 2017. The largest absolute value increases occurred on the borders from Germany/Luxembourg/Austria to the Czech Republic (+970 MW, more than doubled, and 100 MW over the 2015 NTC, following Phase-shifting Transformers – PSTs – commissioning) and from Portugal to Spain (+600 MW, due to numerous works affecting available capacity[44] during the summer of 2016). Significant increases were also observed between Great Britain and Ireland (Single Energy Market – SEM[45] –, returning to 2015 levels)[46], from Denmark to Germany/Luxembourg/Austria (back to its 2014 level), on the border between France and Spain (related to the gradual rise in capacity made available to the market following the commissioning of the Baixas-Santa Llogaia High-Voltage Direct Current (HVDC) interconnector in 2015), and for the Polish technical profile[47] (although the value remained low, especially in the Polish import direction).

76 Decreases were observed for many Norwegian borders (due to planned outages on the Norwegian grid[48]), and on the Danish-Swedish borders (due to internal congestions and interconnectors' maintenance works[49]).

Figure 9: Changes in tradable capacities (NTC) in Europe, excluding differences lower than 100 MW[50] – 2016–2017 (MW, %)



Source: ENTSO-E, NRAs, Nord Pool, 50 Hertz (for Polish profiles) and ACER calculations (2018).

Note: The analysis covered 45 borders in Europe[51], although the Figure excludes border directions with NTC changes lower than 100 MW (absolute values). The bars represent the change (in MW) by comparing 2016 and 2017 NTC values. The indicated percentages show the relative change from 2016 to 2017.

77 In the former Core (CWE) region, NTC values have not been provided since the launch of the FBMC[52] on 20 May 2015. The aim of the new capacity calculation method is to increase tradable capacities as compared to the NTC method.

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44 See: https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202016/projects/P0004.pdf.

45 IE (SEM) refers to the common Irish electricity market (Northern Ireland and Ireland).

46 Capacity decreased in the second half of 2016 (and at the beginning of 2017), following an interconnector fault.

47 The technical profiles describe simultaneous limits to commercial capacity across a set of borders. The Polish profiles refer to the maximum simultaneous export (import) commercial capacity to (from) Poland across its borders with the Czech Republic, Germany and Slovakia.

48 See: https://energinet.dk/-/media/Energinet/El-RGD/El-HAN/Tilgaengelig-transmissionskapacitet/Transmission-capacity-available-to-the-market---Report-Q3_2017.pdf, p. 7.

49 See, for example: https://www.svk.se/siteassets/om-oss/rapporter/2017/swedish-interconnectors-report-no.-13_rapport.pdf, pp. 23-24, 36-37 and 49-50.

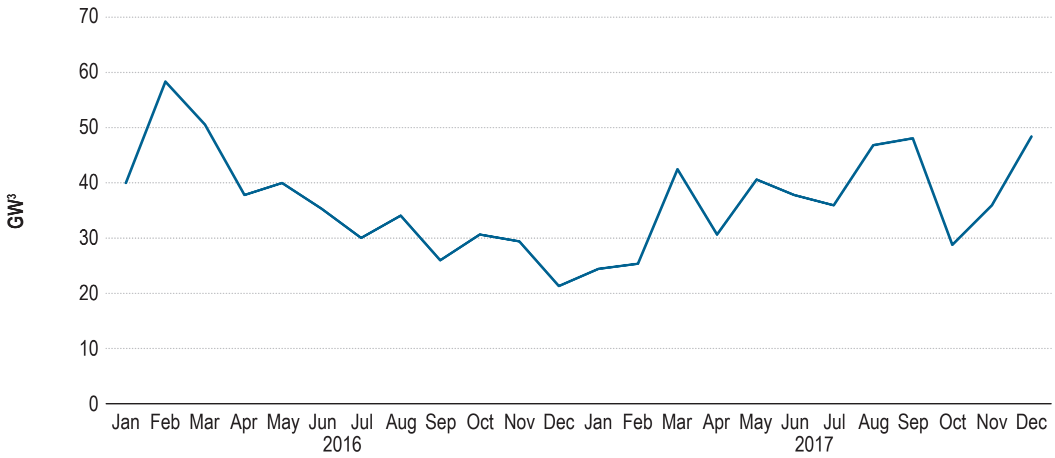
50 The information is presented at bidding zone level (as compared to previous years' reports, where some information was depicted at control area level), except for the PL <> DE/CZ/SK profile.

51 See Table 8 in Annex 1 for the detailed NTC values.

52 More information on FBMC can be found at: http://www.jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D or in the published decision on each of the Core (CWE) NRAs' websites.

78 The indicator for the development of tradable capacity in the Core (CWE) region in 2017 is presented in Figure 10. It shows the size (i.e. the volume[53]) of the FB domain, computed for every hour, but only for the economic direction, i.e. the "directional volume". The latter is defined for the purpose of this indicator as the FB domain volume in the octant[54], which includes the solution of the DA market coupling algorithm, i.e. in the direction corresponding to the bidding zones' net positions[55].

Figure 10: Monthly average FB volumes in the economic directions in the Core (CWE) region – 2016–2017 (GW³)



Source: Data provided by the Core (CWE) TSOs to ENTSO-E and ACER calculations (2018).

Note: The directional FB domain volume lies in the octant that contains the solution of the market-coupling algorithm maximising the market welfare.

79 Figure 10 shows that, after a clear downward trend in 2016, the directional volume increased in 2017. However, the yearly average directional volume remained almost constant at around 36.5 GW3 (with a cubic root of 3.3 GW). The changes are not due to the FB capacity calculation method itself, but to the extent to which internal exchanges are prioritised and, therefore, reduce the available cross-zonal capacity (see Sub-section 3.2.2).

80 Despite the increase in price convergence observed in the Core (CWE) region in 2017 (see Section 2.2), the analysis presented in Sub-section 3.1.2 shows that there is still room to increase available cross-zonal capacity in this region.

81 Overall, the application of the FBMC increases efficiency and cross-zonal capacity available for trading. However, this gain may severely decrease if the amount of cross-zonal capacity is reduced to accommodate flows originating from internal exchanges, as still observed in 2017 (Sub-section 3.2.2).

3.1.2 Ratio between commercial and benchmark cross-zonal capacity

82 This Sub-section analyses the potential scope for increasing available cross-zonal capacity. The underlying assumption in analysing this potential is that, in an efficient zonal market design[56], the only factor limiting trade between two bidding zones is the capacity of the network elements on the bidding-zone borders (i.e. the interconnection lines)[57]. This assumption is equivalent to the principles underlying the Agency's recommendation on

53 The volume is measured in MW³ as the FB capacity calculation problem to be solved is a three-dimensional one in the Core (CWE) region. It involves determining the net position of four bidding zones that maximises social welfare with one dependant variable, which is that the sum of the net positions of all four bidding zones should be zero.

54 An octant corresponds to one of the eight divisions of 3-dimensional space by coordinate planes.

55 For more information, see Sub-section 3.2.1 on 'Evolution of commercial cross-zonal capacity' (p. 80) of the Electricity Wholesale Markets Volume of the MMR 2016, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20ELECTRICITY.pdf.

56 i.e. if the bidding zones are properly defined according to structural physical network constraints.

57 This implies that remedial actions should be applied to avoid cross-zonal trade being limited by the (residual) Loop Flows (LFs) or internal congestions that will always exist in a close-to-optimal bidding zone configuration.

capacity calculation[58].

83 Therefore, the ratio between the actual commercial cross-zonal capacity and the maximum capacity that could be made available to the market (benchmark capacity) indicates the potential scope for increasing the available cross-zonal capacity.

84 The analysis[59] conducted last year showed that HVDC borders tend to perform better[60] than High-Voltage Alternating Current (HVAC) borders, because i) these interconnectors are not impacted by unscheduled flows (UFs)[61] and ii) these interconnectors are usually not considered in the N-1 assessment. As a result, this year, the analysis will focus on borders with HVAC connections (HVAC borders) only, in order to assess the room for improvement on these borders.

85 Several elements may limit the capacity that may be offered to the market on HVAC borders. The first of these elements is the security criterion (i.e. N-1)[62]. The second is the uncertainty of capacity calculation (i.e. a reliability margin). Third, the electricity exchange on a specific border will create an uneven distribution of physical flows on the various interconnectors of that specific border. Therefore, the capacity on a specific border could be further limited to the maximum exchange at which one interconnector of this border is being congested first, while others might not be. Finally, the capacity available on all borders needs to be simultaneously feasible, thus requiring coordination among borders.

86 In order to account for these elements, the Agency has developed a calculation methodology, which is described in the methodological paper on benchmark capacity calculation[63]. Compared to last year's MMR, the methodology includes a number of improvements, particularly with respect to the following three aspects: operational security, simultaneity of NTC values and consideration of remedial actions. As far as operational security is concerned, N-1 contingencies on all network elements (including parallel interconnectors) were taken into account. With regard to simultaneity, NTC values were concurrently computed for each CCR, ensuring that the full combination of exchanges would not overload interconnectors. With regard to remedial actions, they were partially factored in the calculations by considering that the available remedial actions should be, at least, sufficient to guarantee that historical (2017) NTC values were compatible with operational security standards[64]. The results of the calculations may thus be considered as a solid reference point from which to assess the scope for enlarging cross-zonal capacity, although due to the assumptions, the following caveats apply.

87 First, the benchmark capacities could be higher if data not currently available to the Agency on all costly and non-costly remedial actions were considered in the calculations. As mentioned above, they were only considered to some extent by using historical values. Second, the results could be affected by the use of more specific Generation Shift Keys (GSKs)[65]. Third, the commercial capacity is based on average actual observed values (NTC or FB volumes), irrespective of whether some reductions were due to some justified reasons (e.g. planned maintenance). Finally, the computations of benchmark capacities relied on one network situation, whereas observed values were computed on an hourly basis.

58 Recommendation of the Agency No 02/2016 of 11 November 2016 on the common capacity calculation and redispatching and countertrading cost-sharing methodologies, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2002-2016.pdf.

59 See Sub-section 3.2.2 'Ratio between commercial and benchmark cross-zonal capacity' (p. 27) of the Electricity Wholesale Markets Volume of the MMR 2016.

60 The following HVDC borders, however, did not perform well: LT-PL and PL-SE4.

61 See Annex 2 for more information on UFs.

62 The N-1 security criterion is used to protect from potential cascading failures in interconnected grids. It states that "elements remaining in operation within a TSOs control area after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits" (see https://docstore.entsoe.eu/data/data-portal/glossary/Pages/home.aspx).

63 See the methodological paper on 'Benchmark cross-zonal capacity calculation', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ACER%20Methodological%20paper%20-%20Benchmark%20cross-zonal%20capacity%20calculation.pdf. An illustration of the FB capacity calculation process is also included in Sub-section 3.2.2

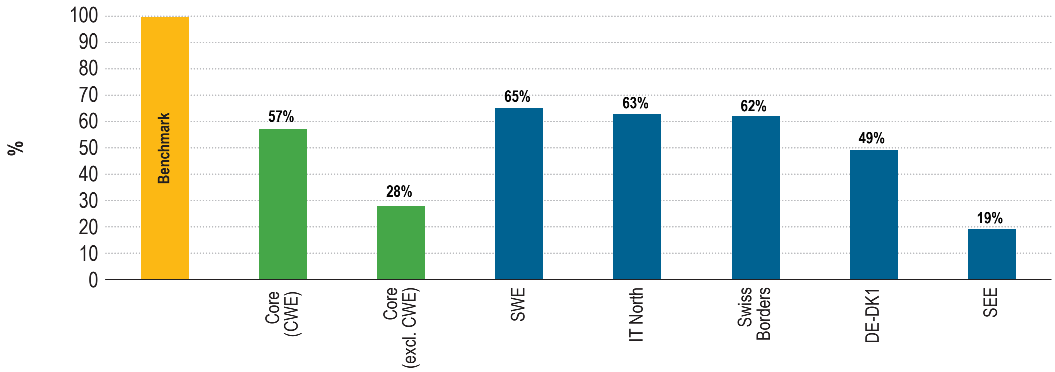
64 So that they should lie within the capacity domain used to compute benchmark NTCs.

65 For the calculations, GSKs proportional to the generation output modelled within a CGM were used.

88 Following the aforementioned methodology, the Agency calculated benchmark capacities for the HVAC borders in continental Europe for which data was available. On borders where FB is envisaged[66], values were compared to benchmark FB domains. On other borders, values were compared to benchmark NTCs computed on a representative Common Grid Model (CGM)[67] provided by ENTSO-E to the Agency.

89 The ratios between commercial capacity and benchmark capacity are analysed below. Figure 11 shows the ratio of actual over benchmark capacity, aggregated by CCRs, in descending ratio order in 2017. It shows that, on average, significantly less than half of the benchmark capacity was offered to the market in the Core (excl. CWE) and SEE regions. The other regions offered between 50 and 65% of the benchmark on average, with SWE, IT North and the Swiss borders performing best. In Core (CWE), the only region currently relying on FBMC, a ratio of 57%[68] was obtained, suggesting significant scope for increasing available cross-zonal capacity.

Figure 11 : Ratio of available tradable capacity to benchmark capacity on HVAC borders per Capacity Calculation Region – 2017 (%)



Source: NRAs, Nord Pool, ENTSO-E's CGM (2017) and ACER calculations (2018).

Note: CCRs where FB Capacity Calculation Methodologies (CCMs) are currently applied or envisaged (based on TSOs' proposals) are shown in green, otherwise Coordinated Net Transfer Capacity (CNTC) methodologies are assumed and shown in blue. On borders where FBMC is applied or envisaged, values are compared to benchmark FB domains, whereas on other borders, average bidirectional NTC values are compared to benchmark NTCs. In order to take profiles into account in the Core (excl. CWE) region, independent (profile-compliant) CZ–DE, CZ–PL, DE–PL, PL–SK NTC values were derived, decreasing these NTCs by 39% on average. The following borders were excluded from the benchmark calculation: borders that do not belong to a CCR, and the Nordic and Baltic borders, because they were not part of the CGM data provided.

90 Unlike in last year's MMR, the ratios between actual and benchmark capacity calculated for this year's MMR are presented only at the regional level and not per border. This is because, due to methodological improvements aimed at guaranteeing simultaneity of NTC values, a number of arbitrary choices had to be made. As a result, individual border values may not be meaningful, and only the sum of these values over a country or a CCR provides a robust picture of the level of cross-zonal capacity which may be achieved. Besides, for CCRs where simultaneity plays a significant role (e.g. Core (excluding CWE)), individual values would depend on the priority levels given to specific borders. This emphasises the importance of implementing FBMC in these regions, as this method allows the allocation of cross-zonal capacity to borders where the value of this capacity is the highest. Moreover, implementing FBMC would also ensure that more transparency is provided with respect to the

66 The Core (excluding CWE) region currently relies on NTC values, but submitted a FB CCM. As a result, the benchmark NTCs were scaled up to mimic enhanced opportunities offered by a FB domain. The average ratio of the Core (CWE) shadow auctions ATCs and FB volumes was used to scale these NTCs, leading to a 60% decrease in the ratio for the Core (excluding CWE) region.

67 A 'common grid model' means a EU-wide data set agreed between various TSOs that describes the main characteristics of the power system (generation, loads and grid topology) and the rules for changing these characteristics during the capacity calculation process. Pursuant to the CACM Regulation, a CGM should be established for each hour. So far, the Agency has been provided with six GCMs corresponding to hours that were representative of the generation and load conditions and the network topology in the period from January to November 2017. TSOs rely on these seasonal CGMs to calculate long-term capacities. The January CGM was used as a representative winter situation. As line thermal limits tend to be lower in summer, benchmark cross-zonal capacities computed for both winter and summer would likely be slightly lower. The impact of this overestimation is limited. For example, on the Spanish-French border (where there are relevant differences between winter and summer thermal limits), the overestimation would likely be 5-7%. On other borders with less winter-summer thermal differences, the overestimation is likely to be smaller.

68 In order to improve comparability with the NTC ratios (based on values in MW), the cubic root of the FB volume was used for the FB ratio. For consistency with other Sections, the directional volume (see paragraph 78) was used.

underlying limitations[69] to cross-zonal trade.

91 To sum up, on most European AC borders, actual NTC values (or the size of the FB domain) are significantly lower than what would be expected from the benchmark capacities (or respectively, the benchmark FB domain). There is large scope for improvement, because an average of only 49% of benchmark capacity on HVAC interconnectors is offered to the market. This capacity may double through improved CCMs.

92 In general, Annex 2 shows that low ratios of actual NTC values over benchmark capacity continued to be correlated with the presence of UFs, such as for example in the Core (excluding CWE) region. Further reasons for the relatively low values of commercial capacity are explained in the following section.

3.2 Factors impacting commercial cross-zonal capacity

93 The relatively low values of the available cross-zonal capacities reflect underlying (probably structural) network congestion, which is not efficiently addressed by the existing bidding zone configuration. As concluded in the previous Section, the gap between the commercial and the maximum possible (benchmark) capacity is on average 51% of the latter for HVAC borders. The capacity calculation process may mitigate the problem. However, there are two key reasons why this mitigation is currently not observed. First, the process applied by TSOs to calculate the capacity made available for cross-zonal trade is insufficiently coordinated, an aspect analysed in Sub-section 3.2.1. Second, TSOs apply preferential treatment to internal exchanges, at the expense of cross-zonal ones, an aspect illustrated in Sub-section 3.2.2.

3.2.1 Level of coordination in capacity calculation

94 Coordination among TSOs is essential for the well-functioning of the IEM, as their actions and how they manage electricity exchanges within and between bidding zones can significantly influence physical flows and operational security in other areas. In this respect, the CACM Regulation requires better coordination among TSOs in the capacity calculation process, both within and between CCRs. The presence of Unscheduled Allocated Flows (UAFs)[70] resulting from non-coordinated capacity allocation on other borders, which reduce the amount of tradable capacity, is a direct consequence of insufficient coordination.

95 This Section includes two analyses. First, it assesses the status of the implementation of the CACM Regulation provisions related to TSO coordination in capacity calculation processes, relying on the scoring methodology introduced in last year's Report[71]. Second, the analysis of the levels of UAFs provides an indication of the extent to which insufficient coordination may influence the amount of cross-zonal capacity offered to the market.

96 To provide an update on the level of TSO cooperation in capacity calculation, NRAs were asked to identify, via a questionnaire, the following key information for each border and capacity calculation timeframe[72]:

- which of the predefined coordination methodologies[73] is applied;
- whether a common grid model is used to calculate capacity; and
- which of the relevant input parameters[74] are (re)assessed in each capacity calculation process.

69 E.g. which network elements (or allocation constraints) limit cross-zonal trade

70 More information on the different types of UFs, i.e. UAFs and LFs, on the underlying definitions and on their magnitude can be found in Annex 2.

71 See the methodological paper on the assessment of capacity calculation coordination, available at https://www.acer.europa.eu/en/Electricity/Market_monitoring/Documents_Public/ACER_Methodological_paper_-_Scoring_methodology_on_the_level_of_coordination_in_capacity_calculation.pdf.

72 Ranging from year-ahead (Y), month-ahead (M), day-ahead (DA) to intraday (ID).

73 See notes below Table 1.

74 Relevant parameters are: a) Reliability margin, b) operational security limits (mostly critical network elements) and contingencies (i.e. outages) relevant to capacity calculation, c) allocation constraints (e.g. import/export limits, losses, etc.), d) generation shift keys, (e) remedial actions.

97 The responses from NRAs on the two sides of each border and for each timeframe were checked for consistency. Congruent answers were evaluated and scored as provided in the methodology. When the information reported by two NRAs for the same border and timeframe was different, the lower level of coordination reported and the consistently reported parameters were further considered in the assessment and respective scoring[75]. This approach was chosen because it is assumed that the coordination on a given border is only as strong as its weakest part.

98 The results of the assessment of the level of capacity calculation coordination for 2017 are presented per border in Table 1, and aggregated at regional level in Figure 12. The notes below the Table provide the definition of the different coordination levels, the capacity calculation parameters (re)assessed and the key features of the applied scoring methodology[76].

Table 1: Application of capacity calculation methods on 50 borders in different timeframes – 2017

Capacity calculation		Coordination level				Parameters (re) assessed on both border sides	CGM used (y = yes, n = no)			
CCR	Border	Year-ahead (Y)	Month-ahead (M)	Day-ahead (DA)	Intra-day (ID)	Y/M/DA/ID	Y/M/DA/ID	DA/ID res.	Score	Evol.
Baltic	EE - FI	BIL	BIL			b/b//	n/n/n/n	24	6.7%	
Baltic	EE - LV	BIL	BIL	BIL	BIL	ab/ab/ab/ab	n/n/n/n	24	13.3%	
Baltic	LT - LV	BIL	BIL	BIL		abe/abe/abe/abe	n/n/n/y	< 24	7.5%	
Baltic	LT - PL			BIL		//abe/	n/n/n/n	24	3.3%	+
Baltic	LT - SE4	BIL	BIL	BIL		abe/abe/abe/abe	n/n/n/n	24	10.8%	+
Channel	FR - GB					///	n/n/n/n	24	0.0%	
Channel	GB - NL	BIL	BIL	BIL	BIL	//c/	n/n/y/n	24	11.3%	
Core (CWE)	BE - FR	BIL	BIL	FB		//abcde/	n/n/y/n	24	32.1%	+
Core (CWE)	BE - NL	BIL	BIL	FB	PC	//abcde/	n/n/y/n	24	37.5%	
Core (CWE)	DE - FR	BIL	BIL	FB		abd/abd/abcde/	n/n/y/n	24	35.7%	
Core (CWE)	DE - NL	BIL	BIL	FB	PC	ab/ab/abcde/b	n/n/y/n	24	41.4%	
Core (excl. CWE)	AT - CZ	BIL	BIL	BIL		abd/abd/ab/	y/y/n/n	< 24	21.4%	+
Core (excl. CWE)	AT - HU	BIL	BIL	BIL		b/b/b/	y/y/n/n	< 24	11.4%	
Core (excl. CWE)	AT - SI	BIL	BIL	BIL		abd/abd/ab/	y/y/n/n	24	16.8%	+
Core (excl. CWE)	CZ - DE					abd/abd/abd/	n/n/n/n	24	0.0%	
Core (excl. CWE)	CZ - PL	BIL	BIL	BIL	BIL	abd/abd/abd/	y/y/n/n	< 24	21.4%	+
Core (excl. CWE)	CZ - SK			BIL		//ab/	n/n/n/n	< 24	0.0%	
Core (excl. CWE)	CZ+DE+SK - PL	BIL	BIL	BIL		abd/abd/abde/	n/n/n/n	24	10.4%	
Core (excl. CWE)	HR - HU	BIL	BIL			b/b//	y/y/n/n	< 24	11.4%	
Core (excl. CWE)	HR - SI	BIL	BIL			abd/abd//	y/y/n/n	< 24	14.3%	
Core (excl. CWE)	HU - RO	BIL	BIL			/b/b/	n/y/n/n	< 24	7.5%	
Core (excl. CWE)	HU - SK	BIL	BIL	BIL		b/b/b/	y/y/n/n	< 24	11.4%	
Core (excl. CWE)	PL - SK	BIL	BIL	BIL		abc/abc/abc/	y/y/n/n	< 24	12.9%	
GRIT	GR - IT	BIL	BIL	BIL		///	n/n/n/n	24	6.3%	
Hansa	DE - DK1	BIL	BIL	BIL	BIL	b//bde/b	n/n/n/n	24	11.3%	+
Hansa	DE - DK2	BIL	BIL	BIL	BIL	///	n/n/n/n	24	8.3%	
Hansa	PL - SE4			BIL		//abcde/	n/n/n/n	24	4.2%	+
IT North	AT - IT	FC	BIL	FC		d//d/	y/n/y/n	24	37.1%	
IT North	FR - IT	FC		FC		cd//cd/	y/n/y/n	24	37.5%	+
IT North	IT - SI	FC		FC		d//cd/	y/n/y/n	24	37.5%	-
IU	GB - IE	BIL	BIL	BIL	BIL	bc/bc/bc/bc	n/n/n/n	24	12.5%	+
Nordic	DK1 - SE3	BIL	BIL	BIL	BIL	b//bce/b	n/n/n/n	24	11.3%	+
Nordic	DK2 - SE4	BIL	BIL	BIL	BIL	b//be/b	n/n/n/n	24	10.8%	+
Nordic	FI - SE1	PC	PC	PC	PC	abd/abd/abd/abd	y/y/y/y	< 24	51.7%	
Nordic	FI - SE3	PC	PC	PC	PC	abd/abd/abd/abd	y/y/y/y	24	60.0%	
Norwegian borders	DK1 - NO2	BIL	BIL	BIL	BIL	b//bce/b	n/n/n/n	24	11.3%	
Norwegian borders	FI - NO	PC	PC	PC	PC	//be/	n/n/n/n	24	27.5%	+
Norwegian borders	NL - NO			BIL	PC	//c/c	n/n/n/n	24	10.0%	+

75 Exceptions applied to five borders (AT-CH, CH-DE, CH-FR, FI-NO and GB-IE), where no data was provided for one of the two sides of a border. In these cases, the only information provided was used for the assessment.

76 For the detailed scoring methodology, see footnote 71.

Capacity calculation		Coordination level				Parameters (re) assessed on both border sides	CGM used (y = yes, n = no)			
CCR	Border	Year-ahead (Y)	Month-ahead (M)	Day-ahead (DA)	Intra-day (ID)	Y/M/DA/ID	Y/M/DA/ID	DA/ID res.	Score	Evol.
Norwegian borders	NO1 - SE3	PC	PC	PC	PC	ab/ab/abe/abe	n/n/n/n	24	42,5%	+
Norwegian borders	NO3 - SE2	PC	PC	PC	PC	b/b/be/be	n/n/n/n	< 24	29,2%	+
Norwegian borders	NO4 - SE1	PC	PC	PC	PC	b/b/be/be	n/n/n/n	< 24	29,2%	+
Norwegian borders	NO4 - SE2	PC	PC	PC	PC	b/b/be/be	n/n/n/n	< 24	29,2%	+
SEE	BG - GR	BIL	BIL			b/b//	n/n/n/n	< 24	6,7%	+
SEE	BG - RO	BIL	BIL			a/abd//	n/n/n/n	< 24	7,5%	
SWE	ES - FR	BIL	BIL			a/a//	y/y/n/n	24	13,3%	
SWE	ES - PT	BIL	BIL			abd/abd//	y/y/n/n	24	16,7%	*
Swiss borders	AT - CH	BIL	BIL	BIL		b/b/ab/	n/n/n/n	24	9,6%	
Swiss borders	CH - DE	PC	PC	PC		///	n/n/n/n	24	18,8%	+
Swiss borders	CH - FR	BIL	BIL	BIL		abcde/abcde/ abcde/	n/n/n/n	< 24	8,3%	+
Swiss borders	CH - IT	FC		FC		d//d/	y/n/y/n	24	35,0%	

Source: NRAs, ENTSO-E, Nord Pool and ACER calculations (2018).

Note 1: Abbreviations and definitions for coordination levels of capacity calculation:

*Capacity calculation timeframes: **Y** – year-ahead, **M** – month-ahead, **DA** – day-ahead, **ID** – intraday*

***Pure bilateral NTC calculation (BIL)** – Capacity calculation on a given border is completely independent of capacity calculation on any other border. TSOs on the two sides of a border calculate the NTC value for this border based only on their own capacity calculations inputs and, subsequently, the lower of the two values is offered for capacity allocation.*

***Partially coordinated NTC calculation (PC)** – Capacity calculation on this border is coordinated with at least one, but not all, the borders significantly affected by exchanges on this border. All TSOs on these borders perform capacity calculation in a coordinated way, using their capacity calculation inputs. When capacity on two borders is coordinated individually by one TSO, but other TSOs are not involved, this should be considered as pure bilateral coordination. * : "Fully coordinated bilateral NTC" now is considered as bilateral NTC, whereas in last MMR it was considered partially coordinated. As a result, the ES–PT grade changed*

***Fully coordinated NTC calculation (FC)** – The calculation of NTC values is performed together on all borders significantly affected by exchanges on this border by the relevant TSOs by including the conditions of all significantly affected networks in the calculation process.*

***Flow-based capacity calculation (FB)** – This process leads to a definition of flow-based parameters, i.e. the power transfer distribution factors (PTDFs), describing how cross-zonal exchanges influence flows on critical network elements, and the available margins on these network elements, describing how much the flows on these elements can further increase due to cross-zonal exchanges. Flow-based capacity calculation in combination with market coupling results in welfare-maximising exchanges between bidding zones, given the capability of the network, which is assessed in a coordinated way.*

***Capacity calculation parameters (re)assessed: a)** Reliability margin, **b)** operational security limits (mostly critical network elements) and contingencies (i.e. outages) relevant to capacity calculation, **c)** allocation constraints (e.g. import/export limits, losses, etc.), **d)** generation shift keys, **e)** remedial actions.*

***CGM** - common grid model used: **y** – yes, **n** – no*

***Evol.** – Evolution of the coordination level, when compared to 2016: + describes an improvement, whereas - describes a deterioration (no symbol means that no change occurred).*

Note 2: Scoring method and benchmark:

***Coordination level (basic scores):** no capacity calculation [empty]: 0 points, BIL: 1 point, PC: 2 points, FC: 3 points, FB: 4 points*

***Parameters reassessed:** For each timeframe, multipliers to the basic scores were introduced depending on how many and which parameters a) to d) were indicated for both sides of a border. The multipliers ranged from 0.5-1.0 and were listed in the methodological description in Annex 3 of the Electricity Wholesale Markets Volume of the MMR 2016.*

***CGM:** If the use of a CGM was not indicated for both sides of a border for a given timeframe, 0.5 points were deducted from the respective basic score.*

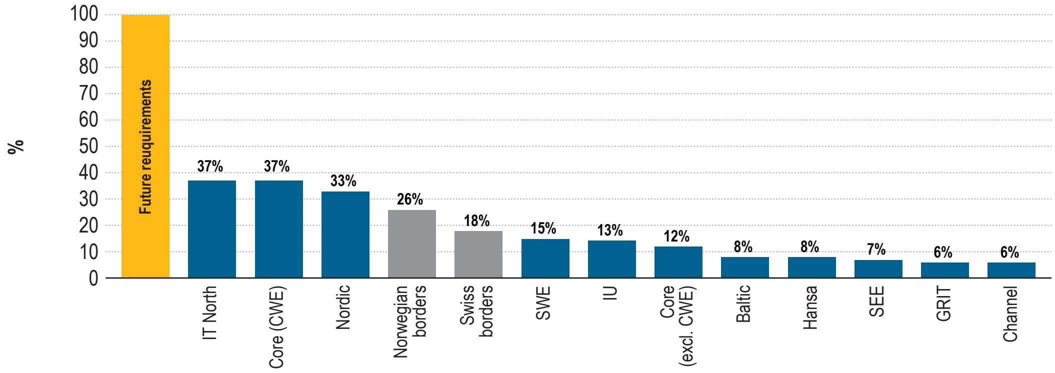
***DA/ID** resolution**:** If capacity (re)calculation at DA or ID level was not done with an hourly resolution (i.e. the same NTC value valid for 24 hours), the basic scores for the DA and ID timeframes were reduced by 0.5 (each). In the case of HVDC interconnections and borders where the FB method is already applied, a calculation resolution of 24 hours was assumed a priori.*

***Score:** The sum of the basic scores per timeframe (adjusted by multipliers or reductions) was calculated for each border and then divided by the maximum possible sum of points (benchmark). The benchmark is 14 for 25 borders, where FB capacity calculation should be applied in the DA and ID timeframes, and 12 on borders where fully coordinated NTC capacity allocation should be applied.*

Note 3: Scope:

50 borders in Europe were analysed. The border 'DE Tennet-SE4' (exempted merchant line) was excluded from the analysis. The scores for the Swiss and Norwegian borders are informative and were calculated for comparison only (as they are not part of the legally defined CCRs).

Figure 12: Regional performance based on the fulfilment of capacity calculation requirements – 2017 (%)



Source: NRAs, ENTSO-E, Nordpool Spot and ACER calculations (2018).

Note: The ratings in the chart were calculated by adding together the scores of 50 borders according to the CCR of which they are part, and dividing them by the maximum possible score (benchmark according to the CACM Regulation). The results of the assessment of Norwegian and Swiss borders are informative and for comparison only (as they do not fall under the legal obligations of the CACM Regulation).

99 The assessment of the individual and regional results of the current implementation analysis suggests generally low fulfilment of the capacity calculation coordination requirements introduced by the CACM and FCA Regulations. The Italy North[77] region, along with the Core (CWE) and Nordic regions, performed best. For the Core (CWE) region, this performance comes mainly from the application of the FB method and the common grid model for the DA timeframe, while for Italy North (respectively Nordic), this is mainly due to the relatively high level of coordination reported for the year-ahead and DA (respectively year-ahead and month-ahead) timeframes. The Channel region shows the lowest level of fulfilment (mainly due to the poor coordination reported on the British-French border). The fact that the lower level of coordination was used in the case of incongruent answers partly explains the low scores for some borders[78].

100 Compared to 2016, significant improvements were recorded in the Nordic[79], Norwegian borders[80], Core (excluding CWE)[81], and Baltic[82] regions[83]. However, the pace of overall improvement remains slow.

101 An important caveat underlying the assessment of the level of coordination is that some related obligations stemming from the CACM Regulation and the FCA Guideline[84] do not yet apply[85]. However, the CCMs related to these elements are currently being developed in order to reach the level required by the CACM Regulation[86]. Therefore, the assessment should be understood as an indication of the room for improvement at this early stage of implementation.

102 The following main issues still lead to low fulfilment on many borders. First, on many borders, TSOs reported that no capacity calculation was performed: ID capacity calculation was not performed for 27 EU borders (+4 non-EU), 10 EU borders for DA, 7 EU borders (+2 non-EU) for month-ahead and 5 EU borders (+1 non-EU) for year-ahead. Second, either a bilateral or partly coordinated capacity calculation method was still applied

77 However, for Italy North, capacity calculation is mostly performed for the main market direction, i.e. Italy imports, and only a yearly calculation is performed for the Italy export direction. The score does not reflect this aspect.

78 Fully consistent answers were provided for the GB-NL and HR-SI borders. Inconsistencies appeared for all other borders.

79 Mostly due to improvements between Denmark and Sweden.

80 Following an increase in the number of capacity calculation parameters estimated.

81 Mainly following improvements on the Czech and Austrian borders.

82 Following improvements on Lithuanian borders.

83 The Swiss borders assessment was also updated following iterations and standardisation of the grading of these borders.

84 See footnote 20.

85 Although similar obligations, with a less detailed legal and governance framework, were already required by Regulation (EC) No 714/2009.

86 Requirements in CACM Regulation and similar requirements applicable since 2006, following Regulation (EC) No 1228/2003, Annex I.

on many borders[87]. There are still only two exceptions where fully coordinated NTC (Italy North) or FB (Core (CWE)) are implemented. These two exceptions apply to the DA timeframe at least.

103 Therefore, significant efforts are still to be made by TSOs and NRAs to improve the coordination of capacity calculation. Improved coordination will contribute to increasing the amount of tradable capacity. In particular, as concluded in previous MMRs, more coordination, e.g. through the introduction of FB capacity calculation, should result in a reduction in the amount of UAFs, which, together with LFs, tend to decrease the amount of tradable capacity.

104 Given the impact of UAFs and LFs on market efficiency and integration, the Agency has been monitoring such flows since 2012. An updated analysis of the amount of these two types of UFs is available in Annex 2.

105 The analysis shows that UAFs decreased from 96 TWh in 2016 to 81 TWh in 2017. Following the implementation of the improvements required by the CACM Regulation, this decrease is expected to consolidate in the coming years. In particular, in the Core (CWE) region, following the implementation of the FBMC (and the improved quality of the data on schedules made available to the Agency), UAFs significantly decreased. Other regions still experienced significant UAFs, suggesting that FBMC helps alleviating UAFs.

3.2.2 Discrimination between internal and cross-zonal exchanges

106 Wholesale electricity markets in Europe are structured in bidding zones; within each bidding zone, any consumer may contract electricity with any generator without limitations. Therefore, to ensure operational security, TSOs usually limit exchanges between bidding zones through the capacity calculation and allocation process.

107 Regulation (EC) No 714/2009 and, in particular, the CACM Regulation, require that capacity calculation and allocation should not result in undue discrimination. This is also stressed by the Agency's Recommendation on capacity calculation[88]. The Recommendation establishes two high-level capacity calculation principles[89]. First, limitations on internal network elements should not be considered in cross-zonal CCMs. Second, the capacity of the cross-zonal network elements considered in the common CCMs should not be reduced in order to accommodate LFs. The Agency expects TSOs and NRAs to follow these high-level principles when developing, approving, implementing and monitoring their CCMs. The Recommendation envisages temporary deviations from these principles when they are properly justified (from an operational security and socio-economic perspective at the EU level) and do not unduly penalise cross-zonal exchanges.

108 In practice, this means that the capacity of the network elements should not be disproportionally allocated to accommodate internal exchanges to the detriment of cross-zonal exchanges. Offering less cross-zonal capacity for trade due to the unequal treatment of different types of electricity exchanges reduces market efficiency and hence may reduce social welfare[90].

109 The prioritisation of internal exchanges may take the form of i) LFs impacting interconnections, as well as ii) reductions of capacity available for cross-zonal exchanges in order to relieve congestion on internal lines. The issue of LFs and more generally of UFs was further analysed in previous editions of the MMR. An update on the volumes of UFs is included in Annex 2.

110 As explained previously, the average gap between the commercial and the maximum (benchmark) capacity is 51% of the benchmark capacity on HVAC interconnectors. Whereas in the mid-term the reconfiguration of bidding zones (in combination with other longer-term measures such as cost-effective network investments) is possibly the most efficient way to address this issue, in the short-term, capacity calculation may contribute to alleviate the gap. However, this is yet to be seen on most European borders, either due to the presence of UAFs resulting from non-coordinated capacity allocation on other borders, or due to the prioritisation of internal exchanges.

87 For example, 22 EU borders (+10 non-EU) for the DA timeframe.

88 See footnote 58.

89 Additionally, the recommendation includes a third principle related to redispatching and countertrading cost-sharing methodologies.

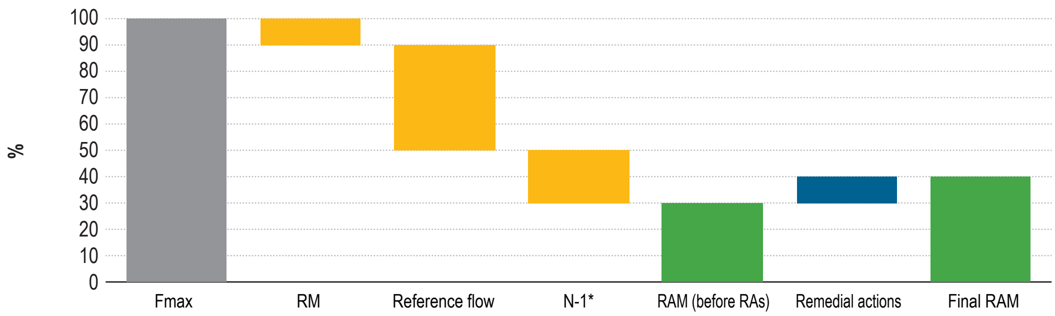
90 A social welfare analysis should also focus on redispatching (and other) costs, and potential long term benefits.

111 In addition, the Agency could access detailed data on FB capacity calculation in the Core (CWE) region. This data allowed further analysis of the issue of discrimination in this region. The analysis is included below. In other regions where capacity calculation is NTC-based, discussions are ongoing between ENTSO-E and the Agency on how to provide data with a level of detail similar to the FB case.

112 The remainder of the Section analyses the frequency and extent to which discrimination of cross-zonal exchanges on individual critical network elements (CNEs) affect the availability of cross-zonal capacity in the Core (CWE) region[91]. The average framework in the Nordic region is then quickly compared with the Core (CWE) region.

113 Figure 13 describes the process deriving the capacity made available for cross-zonal exchange, i.e. the remaining available margin (RAM), for a given CNE. Starting from the maximum admissible flow, a reliability margin accounts for uncertainties (e.g. related to the capacity calculation process). The reference flow also has to be accommodated: this flow describes the CNE flow when no cross-zonal exchanges occur within the CCR; it stems from internal exchanges (and exchanges from outside the CCR). Finally, remedial actions increase the RAM on some CNEs.

Figure 13: Estimation of RAMs on CNEs within the capacity calculation process (%)



Source: ACER (2018).

Note: N-1 contingencies are usually assessed by adding critical network elements with contingency (CNECs), rather than by decreasing the physical margin of CNEs.

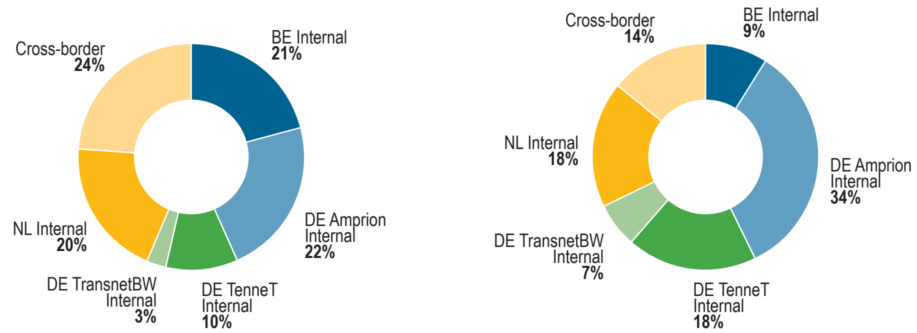
114 The following analysis compares the RAM with the maximum admissible flow on CNEs, thus implicitly relates to the relative share allocated for internal exchanges (and for flows stemming from outside the CCR). The analysis studies CNEs when they are active (i.e. during the hours when CNEs are commercially congested in day-ahead). First, the frequency and location of the elements limiting the FBMC is analysed. Then, the ratio between RAM and the maximum flow (Fmax) is calculated; in order to account for the relative impact of individual constraints on social welfare, an average of these ratios, weighted with the corresponding shadow prices[92], is calculated. Finally, the directional FB volume is compared to the average RAM offered on some interconnectors.

115 Figure 14 describes the share of limiting constraints and shadow prices per element type (internal/cross-zonal line and allocation constraints) and TSO in the Core (CWE) area. Figure 15 focuses on the portion of capacity made available to the market on internal-to-bidding-zone CNEs.

91 The analysis in this Sub-section is limited to the DA timeframe. In the Core (CWE) area, most of the cross-border capacity allocated in the long-term timeframe is not nominated (i.e. the share of long-term nominated capacity accounts for only between 0% and 6% of all nominations, depending on the border). Moreover, the cross-border capacity available for the closer-to-real-time timeframes is a small share of the overall cross-border capacity offered. As a result, the conclusions of this Sub-section can be considered as valid for all timeframes taken together.

92 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 (p. 21-23) of the Electricity Wholesale Markets Volume of the MMR 2016.

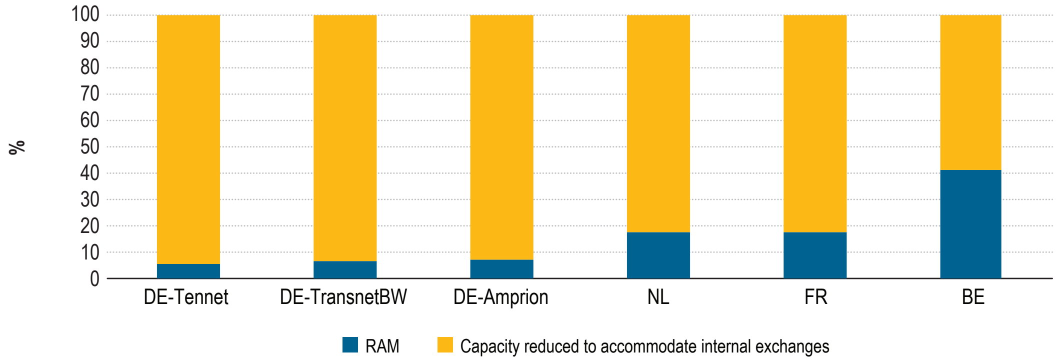
Figure 14: Unweighted share of active constraints (left) and share of constraints weighted with shadow prices (right) constraining the Core (CWE) domain in 2017 per TSO control area and category



Source: Data provided by Core (CWE) TSOs to ENTSO-E and ACER calculations (2018).

Note: Elements with shares of occurrences weighted with shadow prices below 5% were removed from the pie chart (German allocation constraints accounted for 7% of occurrences, but only 0.5% when weighted with shadow prices, French and Dutch allocation constraints accounted for less than 1.5%, French and Dutch internal lines accounted for less than 1.5%).

Figure 15: Weighted-average RAM (expressed as a percentage of Fmax) for cross-zonal exchanges in internal-to-bidding-zone CNEs per TSO control area in 2017 (%)



Source: Data provided by Core (CWE) TSOs to ENTSO-E and ACER calculations[93] (2018).

Note: The weighted average RAM is depicted in blue. The percentages of capacity made available for cross-zonal exchanges for each control area for 2017 are averages of the percentages associated with CNEs in the system, weighted against the hourly shadow price associated with the (active) CNE. RAMs used to calculate the percentages shown in this figure correspond to the capacity available for cross-zonal trade in the DA timeframe.

116 When congestion occurred in the Core (CWE) area, internal lines constrained available capacity much more often (76% of occurrences) than cross-zonal lines (24%) and allocation constraints[94]. Internal Amprion (one of the four German TSOs), Belgian and Dutch constraints each accounted for at least 25% of occurrences of active internal constraints. Amprion's share of internal constraints significantly decreased compared to 2016, from 63% down to 29%; this improvement was mainly due to the introduction of seasonal line thermal limits and dynamic line rating[95]. When weighting occurrences with shadow prices, the relative importance of constraints located inside large bidding zones[96] increased (for Amprion's internal constraints, the share was 50% higher).

93 Unweighted RAM average lead to the following average RAMs (relative to Fmax): DE TenneT 8.2%, DE-TransnetBW 8.3%, DE-Amprion 17%, NL 22%, FR 17%, BE 42%. The main discrepancy occurs for DE-Amprion, where the unweighted average amounts to approximately twice the weighted average.

94 Such constraints are hidden in Figure 14, because they only accounted for a small share of constraints. See below this Figure for their detailed share.

95 See https://www.amprion.net/Dokumente/Dialog/Downloads/Studien/CWE/CWE-Studie_englisch.pdf. Most TSOs already rely on (at least) seasonal line thermal limits.

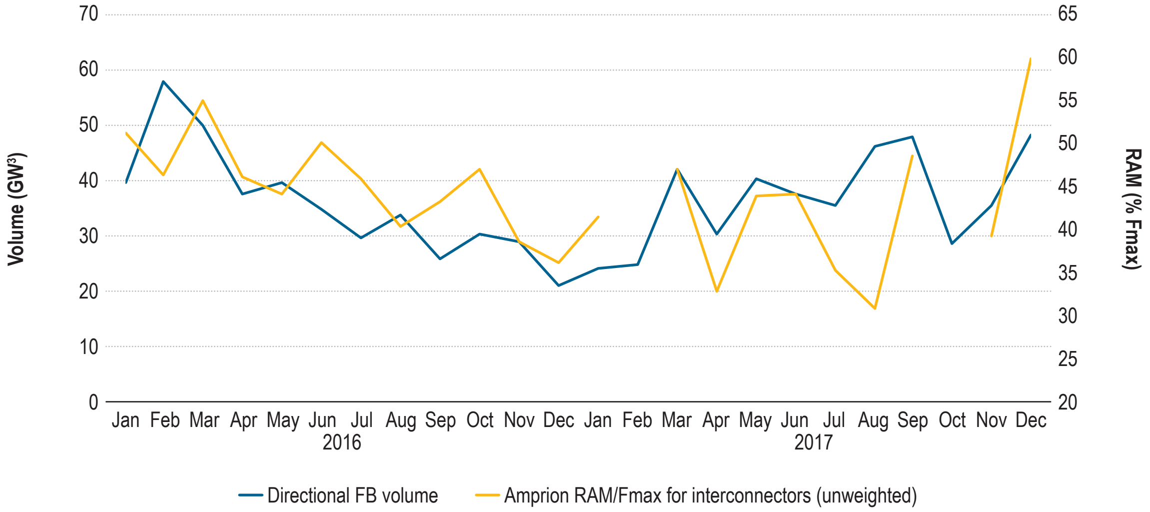
96 In large bidding zones, internal CNEs tend to have lower PTDFs than cross-border CNEs, leading to higher shadow prices (because such prices are approximately inversely proportional to PTDFs). For example, Amprion's internal constraints accounted for 22% of occurrences, but for 34% when weighted with shadow prices.

117 As far as RAMs on congested internal CNEs are concerned, the average margin (relative to Fmax) increased 20% year-on-year, but remained rather low at 12% of Fmax. The average relative margin remained above 15% for Belgium, France and the Netherlands, whereas it remained below 10% for all German TSOs.

118 As a comparison, and based on publicly available data[97] on CNEs in the Nordic region, the average RAM in this region is probably higher than 65% of Fmax. Indeed, for over 90% of CNEs, internal flows and LFs consumed at most 20% of Fmax. Assuming a 10–15% reliability margin (in line with the benchmark capacity calculation methodology[98]), a 65–70% RAM level may be estimated for over 90% of Nordic CNEs.

119 Although exchanges in the Core (CWE) area are affected by a large number of factors, the relative margin offered by Amprion on interconnectors appears to be one of the main factors determining cross-zonal trading possibilities, i.e. the size of the FB domain in the Core (CWE) region. The correlation between (directional) FB volumes and the ratio between RAM and Fmax on Amprion's interconnectors is perceptible when these two variables are displayed together (see Figure 16). The correlation[99] is moderate (factor 0.5) and relatively higher than the correlation between FB volumes and the relative RAM on other TSOs' lines, e.g. on DE TenneT lines (factor 0.29) or on Dutch interconnectors (factor 0.3).

Figure 16: Monthly average FB volumes in the economic directions in Core (CWE), along with average Remaining Available Margin (relative to Fmax) on Amprion interconnectors – 2016–2017 (GW^3)



Source: Data provided by Core (CWE) TSOs to ENTSO-E and ACER calculations (2018).

Note: The directional FB domain volume lies in the octant that contains the solution of the market-coupling algorithm maximising the market welfare.

120 Overall, and despite improvements in Amprion's lines' limitations observed in 2017, constraints associated with internal lines still strongly limited cross-zonal exchanges within the Core (CWE) region, mainly due to the low proportion of capacity available for cross-zonal trade on these lines. The Nordic region illustrates that, when relying on an improved bidding zone configuration, RAM levels may be much higher.

121 The gross welfare benefits[100] from the increase in offered RAM on cross-zonal lines and the removal of internal (and allocation) constraints in the Core (CWE) region were estimated at 156 million euros in 2016[101]. In this

97 See a presentation by Nordic TSOs on "The Nordic Capacity Calculation Methodology (CCM) project": https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/stakeholder_committees/MESC/2018-06-08/2.1%20Nordic%20CCM.pdf?Web=1, slide 27.

98 See footnote 63.

99 Pearson Product-Moment correlation, in congested hours. The Amprion correlation is slightly lower (0.45) when considering congested and non-congested hours. For TSOs that are not mentioned, at least one third of monthly points were missing due to the sporadic occurrence of constraints within their control areas, preventing meaningful correlation calculations.

100 Gross welfare benefits exclude all costs incurred by TSOs for making this cross-zonal capacity available to the market.

101 See Sub-section 4.2.2 on gross welfare benefits of better use of the existing network of the Electricity Wholesale Markets Volume of the MMR 2016.

year's MMR, the gross welfare benefits from the increase of cross-zonal capacity in the Core (CWE) region are estimated together with the increase of cross-zonal capacity on all other borders where market coupling is implemented (see Sub-section 3.3.2).

122 As a summary, the findings presented above emphasise the urgent need to address the currently observed discrimination of cross-zonal exchanges. In the medium term, reconfiguring bidding zones may address the issue. In the short term, the implementation of minimum RAM requirements[102], as well as an upgrade of the CCMs, could somewhat alleviate this problem. In particular, the Agency recommends that the CCMs be implemented according to the requirements in the CACM Regulation and further detailed in the Agency's Recommendation on capacity calculation[103], thus avoiding undue discrimination. Failing to implement these requirements would lead to an indication that a reconfiguration of bidding zones is urgently needed.

3.3 Remedial actions and potential welfare gains from their application

123 Congestion management is intended to optimise the use and functioning of wholesale electricity markets (and the underlying infrastructure). To ensure cost-efficient and relevant price signals, structural congestions should be located on bidding-zone borders and managed through market coupling, rather than through remedial actions.

124 Some remedial measures do not lead to significant costs[104] (e.g. changing grid topology). Others (e.g. redispatching, counter-trading and curtailment of allocated capacity) come at a cost to the system or to TSOs.

125 Sub-section 3.3.1 first focuses on the costs of currently applied remedial actions. Sub-section 3.3.2 then assesses the welfare benefits from augmented cross-zonal capacity in line with the Agency's Recommendation on capacity calculation, and provides an indication of the scope for achieving those benefits by relying on remedial actions.

3.3.1 Remedial actions costs

126 The use of remedial measures in Europe has become frequent, and is likely to become even more frequent in the near future for several key reasons. First, bidding zones in Europe are usually defined according to 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.

127 Second, as the share of intermittent RES generation is increasing, the location of network congestion will probably become more dynamic, which may require more TSOs' interventions, sometimes in timeframes closer to real-time.

128 Third, the CACM Regulation requires that capacity calculation and allocation do not result in undue discrimination. However, as concluded in Sub-section 3.2.2, TSOs apply preferential treatment to internal exchanges, at the expense of cross-zonal ones. The adequate implementation of the CACM Regulation together with the Agency's Recommendation on capacity calculation[105] should mitigate this situation, which may mainly be addressed in the short term by the application of remedial actions.

102 Since 26 April 2018, a minimum of 20% of line thermal capacity, in N-1 situation, is usually made available for the market in the CWE region. For more information, see https://www.acm.nl/sites/default/files/documents/2018-07/aanvraag-tennet-update-approval-package-fb-cwe-da-2018-05-30.pdf#page=65 section 4.2.5.

103 See footnote 58.

104 However, they result from long-term investments in the network (e.g. substations).

105 See footnote 58.

129 Based on the analysis included in previous editions of the MMR, there were grounds to suspect that, due to the lack of correct and adequate incentives for TSOs, the latter often prefer to limit ex-ante cross-zonal capacities in order to limit the costs of remedial actions. This is indeed suggested[106] by Table 2, which shows that the application of remedial actions used to preserve or increase cross-zonal capacity is residual in Europe (e.g. the associated costs are reported as zero or almost zero in 13 countries).

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

Country	Total volume (GWh)	Cost of RAs to preserve/ increase XB capacity (thousand euros)	Total cost (thousand euros)	Relative change 2017/2016	Cost of RAs per MWh load (euros/MWh)
DE	24,313	0	1,161,368	93%	2.2
ES	12,182	5,362	371,475	-28%	1.6
AT	1,757	0	92,405	192%	1.5
GB	10,569	8,978	373,625	24%	1.2
PT			44,525	-63%	1.0
NL	685	37,659	62,355	-5%	0.6
LT	77		1,549	NAP	0.2
NO	896	NA	12,522	-27%	0.1
HU	9	0	2,612	NAP	0.1
LV	4	0	311	-19%	0.0
BE	185	260	2,488	-24%	0.0
FI	35	461	1,756	NAP	0.0
FR	272	2,200	8,583	1289%	0.0
EE	4	102	102	-75%	0.0
CZ	9	0	602	-70%	0.0
SI	2	13	83	NAP	0.0
Total	**51,001**	**55,035**	**2,136,361**	**129%**	

Source: NRAs[107] and ACER calculations (2018)

Note: The Agency requested data on congestion-related remedial actions. NRAs were asked to provide the "Costs of all (redispatch/ countertrading/others) remedial actions used to preserve/increase cross-zonal capacity". All other costs were assumed to relate to internal exchanges. Values refer to costs incurred by TSOs. As the central dispatching model is applied in Greece, Ireland, Italy, Northern Ireland and Poland, costs specifically linked with remedial actions were not available for these jurisdictions. No costs related to costly remedial actions were incurred in Bulgaria, Croatia, Denmark, Luxembourg, Romania and Slovakia. Sweden and Switzerland did not provide details on costs or did not have the data available. The cost of RAs per MWh load is obtained by dividing the 2017 cost of RAs by the 2016 load[108]. For Great Britain, demand in the United Kingdom was used as a proxy. Data relates to 2017, unless stated otherwise. The detailed costs of remedial actions is available in Annex 3.

130 The largest share of remedial actions (hence the largest share of their related costs) aimed at dealing with congestion affecting intra-zonal exchanges. In particular, in 2017, 97% of the cost of all remedial actions was dedicated to ensure that intra-zonal exchanges materialise, rather than to preserve or increase cross-zonal capacity.

131 Compared to 2016, the overall costs of remedial actions increased by 29%, mainly due to increases in Austria (192%), Germany (93%, accounting for more than half of European costs) and Great Britain (24%). In addition, such costs dramatically increased in France (from less than a million euros to 8.6 million euros). In Portugal and Spain, they decreased by 61% and 27%, respectively, but still accounted for over 400 million euros.

106 The relatively low application of remedial actions could also be the result of a very low level of congestion. However, this does not seem to be the case in the majority of countries.

107 The cost for Germany differs from the value provided by BNetzA, the German NRA, in its national publication (1.4 billion euros), because the latter value also includes additional costs for readiness and provision of reserves. Spanish remedial actions costs relate to overloads (34% of costs), voltage issues (35%), transient and other stability issues (20%), DSO-related issues (12%), and may not be fully comparable with other countries. However, RAs reported for other countries may also include such costs, partly because such RAs sometimes address multiple underlying causes (as stated by ENTSO-E in its technical review of bidding zones). The extent to which all of these costs are impacted by bidding zone improvements is uncertain, and should be further investigated.

108 As the 2017 yearly demand values will not be published by Eurostat until late 2018 or 2019, 2016 demand values were used as a proxy throughout this report.

132 When normalized per unit demand[109], costs of remedial actions were greater than or equal to 1.0 euro/MWh in Germany, Spain, Austria, Great Britain and Portugal. In most other countries, such costs were below 0.2 euros/MWh.

133 Overall, Table 2, in combination with the findings of Sub-section 3.2.2, suggests that the level of application of remedial actions does not sufficiently contribute to addressing the discrimination of cross-zonal exchanges in Europe. At the same time, the analysis shows that, in some countries, these remedial actions seem to be widely available for internal purposes. Finally, this analysis does not assess non-costly remedial actions used for internal purposes, which are thus unavailable to increase cross-zonal capacity.

134 Furthermore, in order to provide correct and adequate incentives for TSOs to apply remedial actions with cross-zonal relevance, the costs of these should be distributed between TSOs through a fair cost-sharing methodology[110]. This illustrates the importance of the third high-level principle of the Agency's Recommendation, which envisages that "the costs of remedial actions should be shared based on the 'polluter-pays principle', where the UFs over the overloaded network elements should be identified as 'polluters' and they should contribute to the costs in proportion to their contribution to the overload".

135 In addition, these costs should support the cost-benefit analysis of short-term remedies against longer-term solutions. A disproportionate increase in redispatching costs may indeed reveal the need for medium-term or longer-term structural measures, such as a reconfiguration of bidding zones or network investments. Such investments should only be considered when they are more efficient than other measures.

136 Finally, there is still insufficient transparency concerning the costs associated with remedial actions (in particular, on internal redispatching costs), let alone concerning the technical and economic analyses justifying their use.

3.3.2 Gross welfare benefit of better use of existing network (and remedial actions)

137 Improving the use of the existing network – for example, by mitigating discrimination between internal and cross-zonal flows (which may, in turn, imply relying more heavily on remedial actions) – would improve market integration.

138 Market integration is expected to deliver several benefits, one of which is improved economic efficiency, allowing the lowest cost producers to serve demand in neighbouring areas. This Sub-section shows the extent to which this benefit may be achieved, relying on the 'gross welfare benefits'[111] indicator introduced in previous editions of the MMR. It then estimates the net welfare benefit of increasing cross-zonal capacity through costly remedial actions.

139 For the purpose of this Sub-section, several European Power Exchanges[112] were asked to perform a simulation in order to estimate the gross welfare benefits from market integration for 2017. The algorithm used for the simulations originates from the PCR project (Euphemia), which is used for clearing the single European DA price coupling of regions.

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109 Due to a lack of detailed 2017 data, the 2016 load is used. See footnote 108.

110 Pursuant to the CACM Regulation, TSOs are requested to submit methodologies for cost sharing of countertrading and redispatching. The TSOs of most CCRs submitted such methodologies in the first half of 2018.

111 Gross welfare benefit includes, first, the 'consumers' and 'producers' surplus gained by consumers and producers who participate in power exchanges (welfare is measured as the difference between the prices bid into the market and the matched prices obtained, multiplied by the quantity), and second, congestion rents. The first component measures the monetary gain (saving) that could be obtained by consumers (producers) because they are able to purchase (sell) electricity at a price that is less than the higher (lower) price they would be willing to pay (offer) as a result of changes in cross-border transmission capacity. The second component corresponds to price differences between interconnected markets multiplied by hourly aggregated nominations between these markets. It is important to note that gross welfare benefits, as opposed to net welfare benefits, exclude all costs incurred by TSOs for making this cross-border capacity available to the market. It also does not include potential long-term benefits (or costs).

112 EPEX SPOT, Nord Pool, GME, OMIE, OTE, OPCOM and TGE.

140 On the basis of a set of assumptions[113], an analysis was carried out to estimate the gross welfare benefits from increasing cross-zonal capacity by a certain amount, in accordance with the Agency's Recommendation. For this MMR edition, the geographical scope of the analysis is limited to most of the Continental Europe region. This scope might be widened in future editions of the MMR, depending on available data and resources. The gross welfare benefits were computed for two different scenarios, for each hour of 2017:

- Historical scenario: the gross welfare benefit in 2017 calculated on the basis of detailed historical information such as network constraints, the exchange participants' order books (that is, supply offers and demand bids) and available cross-zonal capacity. For the latter, the relevant Available Transfer Capacity (ATC) and FB constraints[114] were used as a proxy for capacity effectively made available.

- Benchmark incremental scenario: the same as the historical scenario, except for the set of constraints defining cross-zonal capacities. The historical FB domain in the Core (CWE) region was replaced by a new set of constraints consistent with the Agency's benchmark FB domain (see Sub-section 3.1.2). This benchmark domain assumes the removal of constraints associated with internal CNEs within the Core (CWE) region, and a RAM on interconnectors equal to 85% of thermal capacity (Fmax). The allocation constraints defining import and export limits are also removed. The NTC values on the other borders of Continental Europe were also replaced with the benchmark NTCs (from the 2016 MMR[115]). All other elements remain unaltered.

141 The calculated difference in gross welfare benefit between the historical and the benchmark scenario amounts to 568 million euros per year in 2017. The gross benefits of implementing the Agency's Recommendation extrapolated to the whole of Europe (based on available cross-zonal capacity[116]) amount to more than 1 billion euro per year.

142 These gross benefits could be obtained through various options. Such options include updating the bidding zones' configuration, improving coordination of capacity calculation or increasing the use of redispatching actions to increase cross-zonal capacity. The analysis below illustrates the marginal net benefits from relying on costly remedial actions to increase cross-zonal capacity in the Core (CWE) region.

143 Increasing cross-zonal capacity by activating[117] costly remedial actions improves market welfare. However, it comes at the cost of remedial actions. The following analysis will estimate whether it could be beneficial to 'increase' the physical capacity of a limiting[118] CNEC (through costly remedial actions) for a given hour, in order to allow more cross-zonal exchanges. A small overload would be allowed when computing the market outcome (leading to more cross-zonal exchanges). The overload would then be tackled through costly remedial actions.

144 The benefit from increased cross-zonal capacity comes from enhanced cross-zonal exchanges raising market welfare. In the Core (CWE) region, shadow prices quantify this benefit, i.e. the incremental market welfare derived from an additional MW of capacity on a limiting network element[119]. The average shadow price over all limiting Core (CWE) elements in 2017 was 146 euros/MW.

145 The cost from increased capacity comes from the redispatching measures required to bring the flow on the limiting element back within safe limits. The volume of energy to be redispatched needs to be estimated; it is then combined with the average unit cost of redispatching[120]. The redispatching volume depends on the availability of

113 See the methodological paper on benefits from the application of the Agency's recommendation on capacity calculation, available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ACER%20Methodological%20paper%20-%20Benefits%20from%20the%20application%20of%20the%20Agency%27s%20recommendation%20on%20capacity%20calculation.pdf.

114 ATC was used for borders where capacity calculation is CNTC-based, and FB constraints for the borders within the Core (CWE) region where capacity calculation is FB.

115 See Table 6 (p. 62) of the Electricity Wholesale Markets Volume of the MMR 2016.

116 In the simulation exercise, the cross-zonal capacities were increased up to the benchmark values, for borders within the MMC and 4MRC regions for which benchmark capacities were available, and then extrapolated based on average yearly NTC.

117 In practice, remedial actions would be reserved for increasing capacity, but would only be activated if a constraint occurs in real time.

118 Increasing the capacity of a non-limiting network element does not affect the market outcome, and thus leads to neither cost nor benefit.

119 Otherwise, combining price spread and PTDFs allows to approximate this value.

120 The average unit cost of redispatching is the average price spread between average upward and downward redispatching costs that are required to relieve congestion while keeping the system in balance.

remedial actions close to the overloaded branch. It would usually be more efficient to change the dispatch of a few plants close to the overload, because they would have a greater impact on the flow on the overloaded element. The volume to redispatch in order to solve the constraint is inversely proportional to the average influence that redispatching actions have on overloaded elements. Based on data provided by a few NRAs[121], the average influence coefficient was 73%, meaning that, for each MW of overload, approximately 1.4 MW of redispatching[122] would be required. The average cost of energy involved in remedial actions provided by CWE NRAs for 2017 was 49 euros/MWh. Thus, the cost[123] of managing the overload during one hour would be 69 euros/MW.

146 Based on the analysis above, the average benefit from 'increasing' physical capacity on limiting network elements through remedial actions seems to be 77 euros/MW in the Core (CWE) region. The simplified cost-benefit analysis is valid for small cross-zonal capacity increases, when historical values may be a good proxy of expected benefits. If this practice becomes widespread, the cost of reserving additional remedial actions should also be taken into account. Moreover, detailed analyses should be conducted to assess precisely when (and under which criteria) such a solution would be beneficial.

147 Finally, additional benefits may be expected from enlarging the amount of available cross-zonal capacity in the long term. These benefits include stronger incentives for the efficient reinforcement of the internal networks, stronger TSOs' cooperation close to real time, stronger incentives to coordinate national energy policies and, finally, stronger incentives to improve the bidding zone configuration.

3.4 Efficiency of current bidding zone configuration (market report pursuant to Article 34(1) of the CACM Regulation)

148 Due to the limited capacity of the EU electricity transmission infrastructure, the efficiency and functioning of wholesale electricity markets and network operational security are affected by electricity flows from source to sink. Congestion management methods and market design arrangements are intended to handle these flows in the most efficient way, while ensuring secure operations and providing for an appropriate framework for the optimal use and development of the EU electricity system.

149 The EU Electricity Target Model prescribes that structural network congestion should be handled through a bidding zone-based market structure. Electricity exchanges within a bidding zone are unlimited (and do not directly pay for congestion costs), then a combination of preventive and curative methods allows the management of the underlying infrastructure limitations within and between bidding zones. Preventive methods mainly define ex-ante limitations to cross-zonal trade by calculating cross-zonal capacities and efficiently allocating them to market players. Curative methods, e.g. redispatching or counter-trading[124], update the network topology and dispatch pattern when relevant, to avoid jeopardising operational security.

150 An efficient bidding zone configuration should aim to promote robust price signals for both efficient short-term utilisation and long-term development of the power system. It should also limit overall system costs (including costs related to generation, network and remedial actions). Achieving these targets requires a definition of bidding zones based on structural congestions, i.e. so that structural congestions lie between bidding zones (and congestions that remain inside each bidding zone are residual).

151 When the bidding zone configuration does not reflect the underlying structural congestions - and is instead based on national borders (the most common approach so far) -, internal exchanges may lead to externalities, including LFs 'consuming' capacity on cross-zonal elements, and internal overloads leading to large amounts of costly remedial actions. It may also lead to distorted economic signals and economic transfers among players, along with discrimination between bidding zones.

121 Only NRAs from Hungary (influence coefficient of 50%), Latvia (70%) and Slovenia (100%) provided data.

122 1 MW of redispatching refers to an increase of 1 MW compensated by a decrease of 1 MW in another location.

123 Such a cost may be higher than the average cost of remedial actions, because the cheap remedial actions have already been used. As a result, more expensive remedial actions may have to be activated to increase cross-zonal capacity.

124 Remedial actions may also be applied as a preventive measure in some cases, e.g. to avoid undue discrimination of cross-zonal and internal exchanges during capacity calculation.

152 Pursuant to Article 34(1) of the CACM Regulation, the Agency is tasked to "draft a market report to assess the efficiency of current bidding zone configuration every three years", and "shall request ENTSO-E to draft a technical report on current bidding zone configuration". ENTSO-E also drafted a bidding zone review report[125], which encompasses many aspects, such as forward, DA and ID markets' efficiency, redispatching costs, market liquidity, relevance of price signals, and non-discrimination between internal and cross-zonal exchanges. However, due to severe methodological problems, no reliable quantitative results were obtained. Consequently, it relied mainly on qualitative, expert-based opinions to assess various bidding zone configurations. The report concluded that "the evaluation presented in this First Edition of the Bidding Zone Review does not provide sufficient evidence for a modification of, or for maintaining, the current bidding zone configuration. Hence, the participating TSOs recommend that, given the lack of clear evidence, the current bidding zone delimitation be maintained".

153 This Section constitutes the Agency's market report evaluating the impact of the current bidding zone configuration on market efficiency, in accordance with Article 34(1) of the CACM Regulation, as previously described. The analysis presented in this Section focuses on assessing whether structural congestions are located between bidding zones, and whether significant discrimination occurred between internal and cross-zonal exchanges, in order to infer whether these issues hampered overall bidding-zone efficiency. Two criteria are used to measure these aspects: the amount of available commercial cross-zonal capacity, and the application of (costly) remedial actions.

154 This market report does not provide recommendations for changes in bidding zones (e.g. splitting or merging some bidding zones). Instead, it assesses the need for further detailed studies where there are indications of congestions not being properly addressed by the current bidding zone configuration. As a result, many aspects[126] (such as forward markets liquidity, relevance of long- term investment signals, etc.) are beyond the scope of this market report, but should be assessed when investigating potential improvements related to bidding zone configurations.

155 This Section is structured as follows: first, the study methodology (and indicators) is illustrated, then the results are presented and lead to conclusions with respect to the need for improvements to be investigated.

3.4.1 Methodology

156 The assessment is carried out throughout Europe for the 2015–2017 period, subject to data availability. Recent investments may affect the results and should be reflected in future MMRs.

157 The main assessment criteria[127] monitor cross-zonal capacity and costly remedial actions (the detailed specifications of the various indicators and their associated threshold values are provided in Annex 4), as described below.

1) The available cross-zonal capacity criterion assesses discrimination between internal and cross-zonal flows on HVAC borders by comparing historical NTCs[128] with benchmark NTCs. With low discrimination and structural congestions located on borders, NTC values should be close to the benchmark values. Lower values may indicate discrimination, which may be the consequence of various underlying issues, including lack of coordination, LFs or congestions on internal elements. The cross-zonal capacity assessment also takes price spreads into account, in order to relate it to the potential economic value of the capacity.

125 See the report drafted in line with Article 33 of the CACM Regulation, available at: https://docstore.entsoe.eu/Documents/News/bz-review/2018-03_First_Edition_of_the_Bidding_Zone_Review.pdf.

126 In line with Article 33 of the CACM Regulation.

127 An informative assessment is also performed on LFs and is presented in Table 11 in Annex 4.

128 For borders in the Core (CWE) FB area, the cubic root of the directional FB volume approximates the equivalent NTC.

2) The costly[129] remedial actions criterion describes the direct cost (and related volume) of allowing unlimited exchanges within a bidding-zone and of ensuring non-discrimination with cross-zonal exchanges. As structural network congestions should lie between bidding zones, costs related to internal exchanges should remain relatively low. Otherwise, they may indicate that a large part of the congestions are handled through remedial actions rather than through cross-zonal congestion management between bidding zones within coupled markets, which should be the case for cost-effectiveness and price signals relevance. In order to make these values comparable across bidding zones, the information was normalised per unit demand. This indicator is not used for markets which rely on the central dispatching model[130], as in this case it is not possible to separate the cost of network congestion from the global dispatch.

158 The performance of each country or bidding zone is assessed for each criteria, and is classified into three possible categories based on a set of threshold values that are described in Annex 4. These three categories are: 1 - poor performance, 2 - to be closely monitored, 3 - adequate performance.

159 A bidding zone configuration is considered inefficient, and should be improved, when it performs poorly on either the cross-zonal capacity or costly remedial actions criteria. When it performs poorly on both criteria, the improvement should be investigated with priority, because, in this case, it is unlikely that remedial actions would solve the significant discrimination of cross-zonal flows. Moreover, when an issue appears in one bidding zone, its cause may come either from this bidding zone or from another bidding zone. As a result, bidding zone improvements should be investigated at least at regional level.

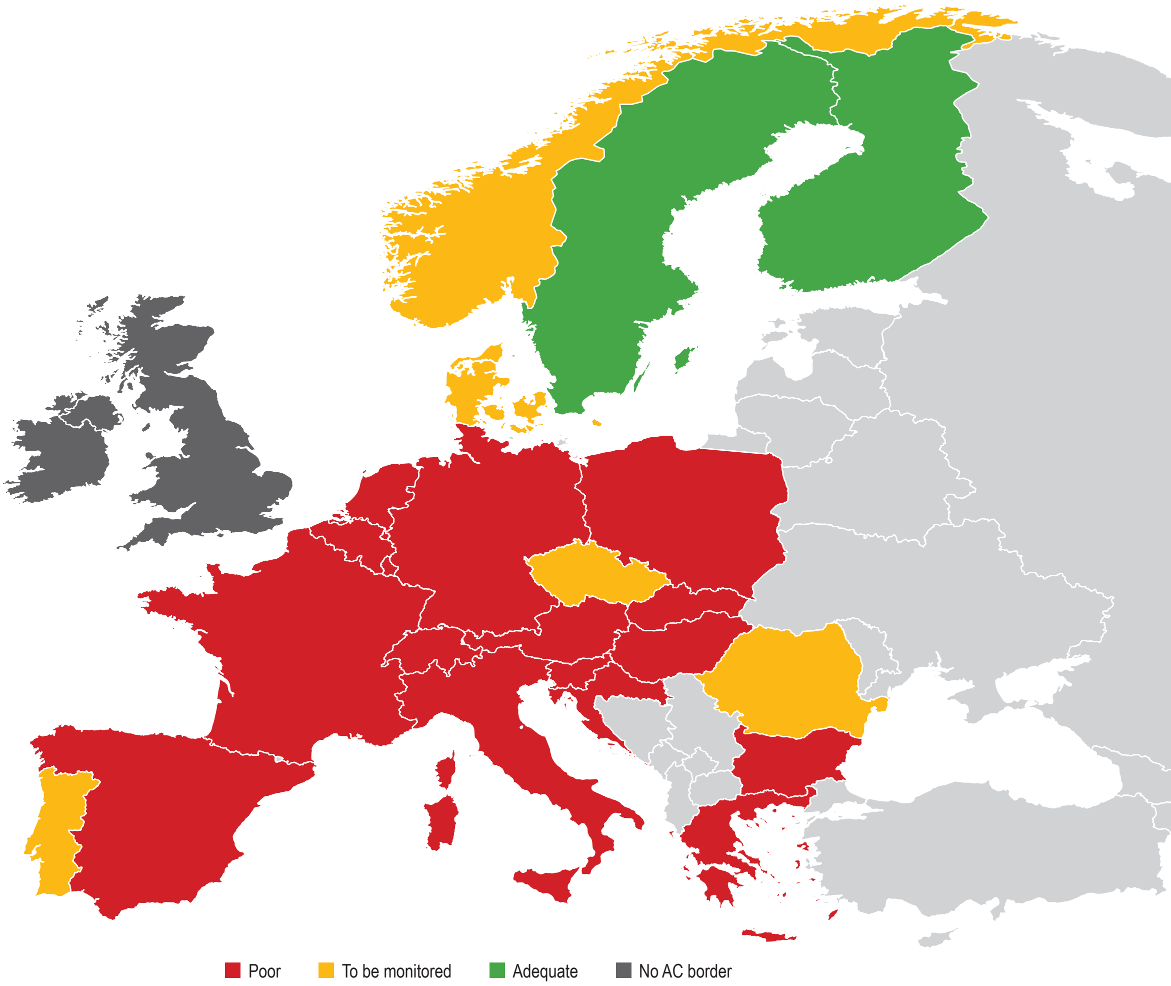
129 Currently, non-costly remedial actions are much harder to track and value, and indirectly affect costly remedial actions. Thus, the overall comparison possibilities are limited to a certain extent, although the costly remedial actions indicator is not affected.

130 In a central dispatching model, the dispatching is computed (and regularly updated) in order to cost-effectively ensure simultaneously power supply, required reserve levels, network constraints fulfilment…As a result, the additional cost specifically coming from network constraints is usually not available.

3.4.2 Results

160 Figure 17 provides a visual representation of how countries fare with respect to available cross-zonal capacity.

Figure 17: National performance[131] according to the level of cross-zonal capacity compared to benchmark capacity on HVAC interconnectors in Europe – 2015–2017



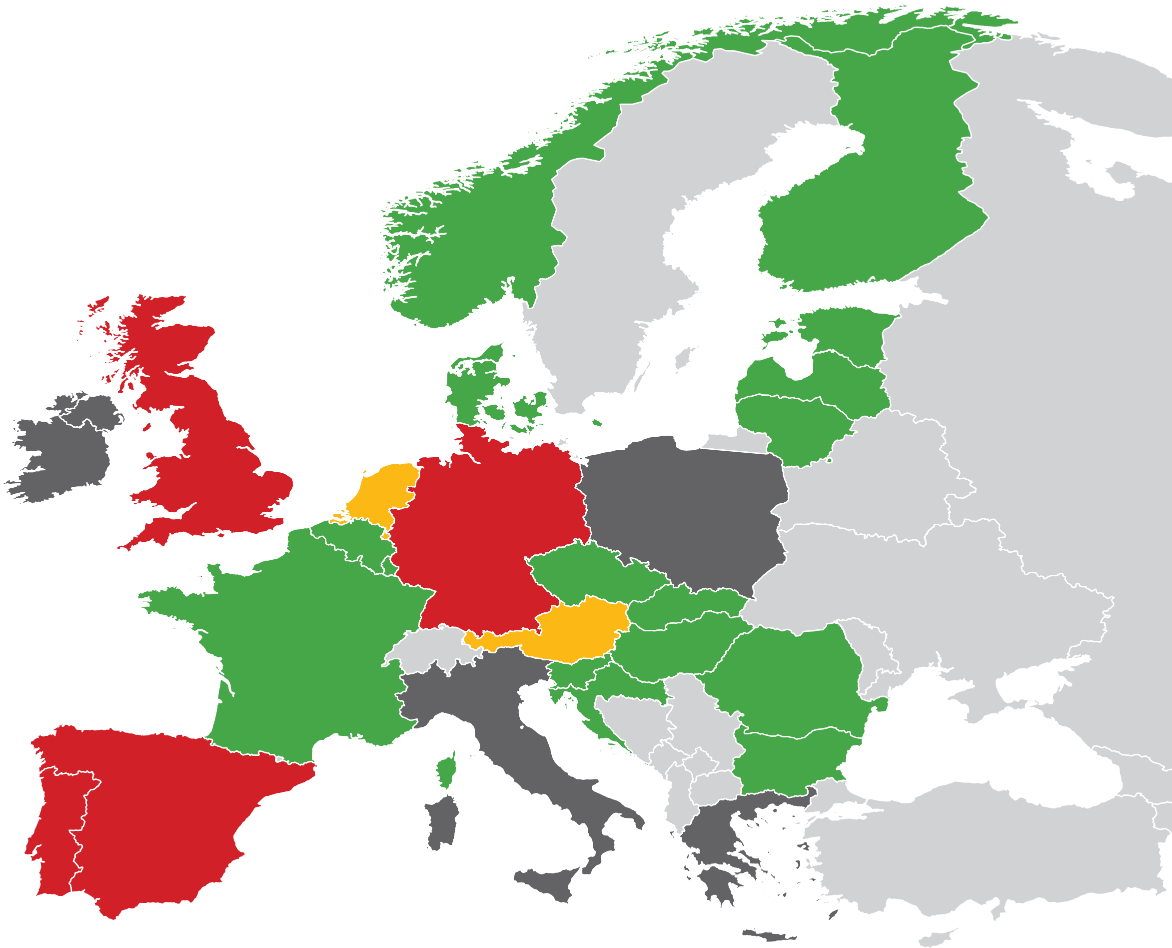
Source: NRAs, ENTSO-E and ACER calculations (2018).

Note: Performance was assessed by comparing cross-zonal capacity made available for trading to benchmark capacity on HVAC borders in 2016, and by price convergence in the period 2015-2017. Poor performance for a given country corresponds to a situation where less than 75% of the average benchmark capacity on HVAC borders is provided to the market, and where the average price spreads with neighbours is above 5 euros/MWh. The detailed qualification methodology is described in Annex 4. Luxembourg is assumed to perform like Germany. The Italian performance is assessed for the Italy North border. Great Britain and Ireland (SEM) do not have AC borders, and are therefore depicted in dark grey. No information was available for Estonia, Latvia, and Lithuania, and these countries are depicted in grey.

131 For Finland, Norway and Sweden, a simplified assessment allows to estimate that their cross-zonal capacities amount to approximately 80% of benchmark. See paragraph 276.

161 Figure 18 shows the relative performance of countries with respect to the use of the costs of remedial actions.

Figure 18: National performances with respect to the use of costly remedial actions – 2015–2017



Source: NRAs, ENTSO-E and ACER calculations (2018).

Note: Poor performance corresponds to the cost of remedial actions per unit of demand being above 1.0 euro/MWh, performance to be monitored corresponds to the cost of remedial actions per unit demand being between 0.2 and 1.0 euro/MWh, and adequate performance corresponds to the cost of remedial actions per unit demand being below 0.2 euros/MWh. The detailed qualification methodology is described in Annex 4. As the central dispatching model is applied in Greece, Ireland, Italy, Northern Ireland and Poland, costs specifically linked with remedial actions are not available; as a result, these jurisdictions are depicted in dark grey. Sweden is depicted in grey, because the information on costly remedial actions was not made available by the Swedish TSO.

162 Figure 17 and Figure 18 lead to the following conclusions. Overall, apart from Finland and Sweden, most countries performed poorly on cross-zonal capacity. Sixteen countries performed adequately on remedial actions. However, Germany, Great Britain, Portugal and Spain, performed poorly on this criteria, followed by Austria and the Netherlands. Only Finland performed adequately on both criteria, whereas Germany and Spain performed poorly on both criteria.

163 Based on the two criteria shown in the above figures, Table 3 brings together the recommendations for bidding zone improvements in Europe. The Table also includes information on the priority of the improvements to be investigated, and on the underlying issues likely triggering the recommendation. Investigations should be conducted with priority in the Core, Hansa and SWE regions, because of low cross-zonal capacity and high costs of remedial actions. The issues look more critical in the Core and Hansa regions, because of the very low level of cross-zonal capacity offered on some borders in these regions[132]. Improvements should also be investigated in the Channel and IU regions, due to the relatively high costs of remedial actions arising from internal exchanges

132 Whereas the SWE region performs relatively better, see e.g. Figure 11.

in GB; however, these internal congestions do not seem to lead to discrimination of cross-zonal exchanges[133]. An investigation may also be useful in the Italy North and SEE regions, in order to tackle the low levels of cross-zonal capacity.

Table 3: Need for investigating bidding zone improvements

Region	Improvement to be investigated	Priority level	Cross-zonal capacity	Costly remedial actions	Potential underlying issue
Core	Yes	High	Poor	Poor	Internal congestions in Germany and, to a lesser extent, in Austria and the Netherlands. Large LF volumes.
Hansa	Yes	High	Poor	Poor	Internal congestions in Germany.
SWE	Yes	High	Poor	Poor	Internal congestions in Spain.
Channel	Yes	Moderate		Poor	Internal congestions in GB.
IT North	Yes	Moderate	Poor	To be monitored	Internal congestions in Austria. Significant LF volumes between Austria and Italy.
IU	Yes	Moderate		Poor	Internal congestions in GB.
SEE	Yes	Moderate	Poor	Adequate	
Baltic	No			Adequate	
GRIT	No				
Nordic	No		To be monitored	Adequate	

Source: NRAs, ENTSO-E and ACER calculations (2018).

Note: The internal congestions identified as potential underlying issues in the last column are inferred based on the costs of remedial actions, as the overwhelming majority of such costs is incurred due to internal constraints[134]. The Channel, GRIT and IU regions do not have AC borders; as a result, the assessment of cross-border capacity does not apply to them. Lack of information prevented an assessment of cross-zonal capacity in the Baltic region.

164 To facilitate these improvements, the bidding zone review envisaged in the CACM Regulation is the obvious approach. The bidding zone reviews should be neutral and unbiased and should strive to focus only on technical and economic aspects. More specifically, the bidding zone review should be conducted according to the following high-level principles. First, when considering alternative bidding zone configurations, a model-based approach should be used, and complemented by an expert-based approach. Second, the methodology should be clear and complete, and a wide agreement on criteria (and their importance) should be sought before conducting simulations. For example, a crucial aspect to be agreed upon is the study time horizon and the inclusion of future network investments. In the Agency's view the time horizon should not be longer than five years and only network investments with certainty about their execution should be considered. Third, the process should be transparent, and should allow for regular regulators' and stakeholders' involvement throughout the study. Finally, as the legal framework supporting bidding zones reviews is currently under discussion[135], these reviews should only start when a more robust governance framework has entered into force.

165 Until such a framework is in place, the TSOs in each CCRs should consider the option of directly improving the bidding zone configuration, by identifying structural congestions, which, according to Regulation (EC) No 714/2009, shall be addressed by capacity allocation mechanisms, thus resulting in a change of the bidding zone configuration.

133 Congestions mostly seem to occur from Northern to Southern Great Britain. Interconnectors all rely on HVDC lines, are mainly located at the Southern end of Great Britain, and tend to regularly be importing, thus helping to relieve some internal congestions. However, congestions sometimes seemed to impact cross-zonal capacities over the Moyle interconnector with Northern Ireland (SEM).

134 See Sub-section 3.3.1.

135 Within the 'Clean Energy for All Europeans' package discussions.

4. Market liquidity

166 Market liquidity is a key indicator of a well-functioning electricity market. It can be defined as the feature of the electricity market whereby a large number of market participants are able to sell/buy products in large quantities, quickly, without significantly affecting the product's price and without incurring significant transaction costs.

167 Market liquidity can be measured in several ways. Two of the most frequently used metrics of liquidity are: 1) the 'churn factor', which is defined as the volumes traded through exchanges and brokers expressed as a multiple of physical consumption, and 2) the 'bid-ask spread', which is 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 is related to the 'size' of the market, while the second provides an indication of the costs that market participants may incur when entering into a transaction.

168 Based on these metrics, this Chapter provides an update on the liquidity in the forward market timeframe (Section 4.1) and on the status of the liquidity in ID markets prior to the implementation of the SIDC[136] throughout Europe (Section 4.2). Whereas for forward markets, the Agency has access to churn factors and bid-ask spreads in most European markets, for ID markets, information on bid-ask spreads is currently not readily available for analysis. Therefore, the analysis of ID market liquidity is mainly based on churn factors and market volumes.

4.1 Forward market liquidity

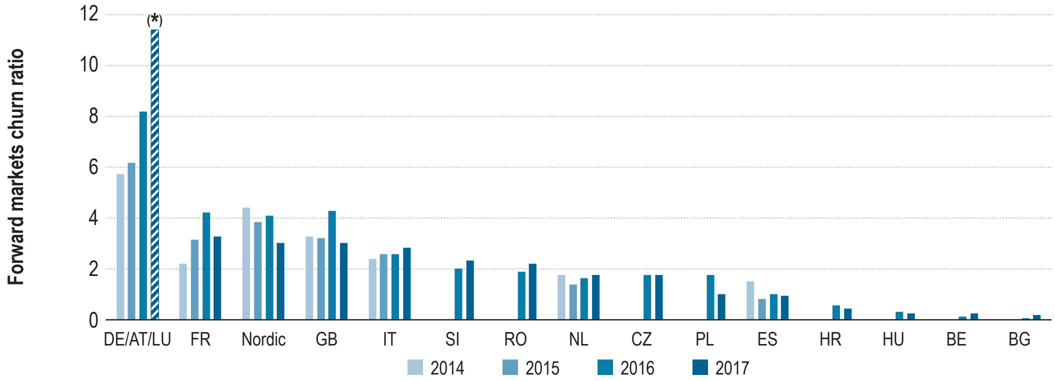
169 Figure 19 presents the churn factors[137] of the largest European forward markets in the period from 2014 to 2017. It shows that Germany/Austria/Luxembourg continued to be the market with the highest churn factor in Europe in 2017. Between 2016 and 2017, the main increases among the analysed markets were recorded in Romania (with a churn factor increase of 19%), the Netherlands (+10%) and Italy (+9%). Meanwhile, relatively large decreases were observed in Poland (-43%), Great Britain (-30%)[138], the Nordic markets (-26%) and France (-23%).

136 The SIDC with implicit continuous cross-zonal capacity allocation through the commercial cross-border ID (XBID) project went live on 12 June 2018.

137 For the purpose of calculating churn factors, only the products used to hedge (local) bidding zone price risks were considered, whereas instruments used to hedge cross-zonal price risk such as transmission rights or contract for differences were not taken into account. The contribution of cross-zonal hedging instruments to 'traded volumes' represents, in general, no more than half the physical consumption in the relevant bidding zone. Some exceptions apply, such as Slovenia or Croatia where they appear to represent more than 100% of the consumption. See, e.g. table 5 of the Report "European Electricity Forward Markets and Hedging Products – State of Play and Elements for Monitoring" available at: http://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ECA%20Report%20on%20European%20Electricity%20Forward%20Markets.pdf.

138 Based on information provided by Prospex Research Ltd. According to Ofgem, the British NRA, the decrease was lower (-22%).

Figure 19: Churn factors in major European forward markets – 2014–2017



Source: European Power Trading 2018 report, © Prospex Research Ltd and NRAs (2018).

Note: The figure shows estimates of total volumes traded as a multiple of consumption from Eurostat (see footnote 107).

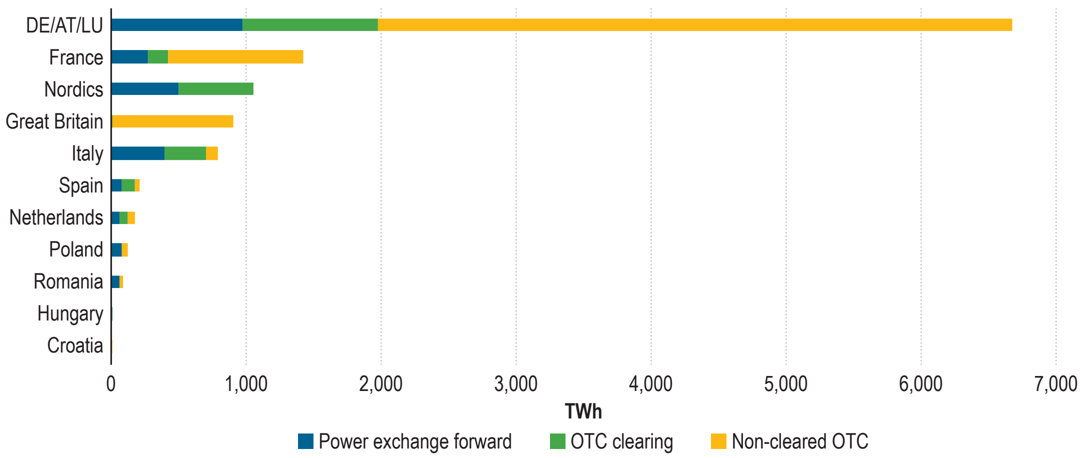
For Germany, the traded volumes from 2014 to 2016 are based on Prospex data, while the 2017 volumes are based on data provided by the German NRA. As the significant annual increase derived from this value may be related to the data source change rather than to an increase of the trading activity, the German churn factor in 2017 is depicted using a different pattern (*).

For France, Great Britain, Italy, the Netherlands, the Nordic area, and Spain, the traded volumes data from 2014 to 2017 were provided by Prospex. For Belgium, Bulgaria, Croatia, the Czech Republic, Hungary, Poland, Romania and Slovenia, the traded volumes data from 2016 to 2017 were provided by the respective NRAs. For Belgium and Bulgaria, the traded volumes are based only on contracts traded at the power exchange. For Great Britain, demand in the United Kingdom was used as a proxy.

170 The relatively large decreases in forward market traded volumes in the four above-mentioned markets are unlikely to be explained by only one factor. Some of these factors are market-specific. For example, in Great Britain, the decrease was the result of trading volumes returning to their longer-term trend, following the exceptional increase in 2016 due to high prices and volatility associated with French nuclear issues at the end of the year. In France, the decrease could have been largely caused by the increase in market prices above the price under the Regulated Access to Incumbent Nuclear Electricity (ARENH). Consequently, independent suppliers might have preferred to source energy and hedge risks in 2017 directly from the incumbent (Électricité de France) at ARENH levels, rather than in the market.

171 As indicated last year, the structure of forward markets, which is shown in Figure 20, varies widely across Europe. Over-the-counter (OTC) trading was the segment of forward markets that declined the most, with a drop of approximately 20% in 2017.

Figure 20: Forward market trading volumes per type in the biggest European forward markets – 2017 (TWh)

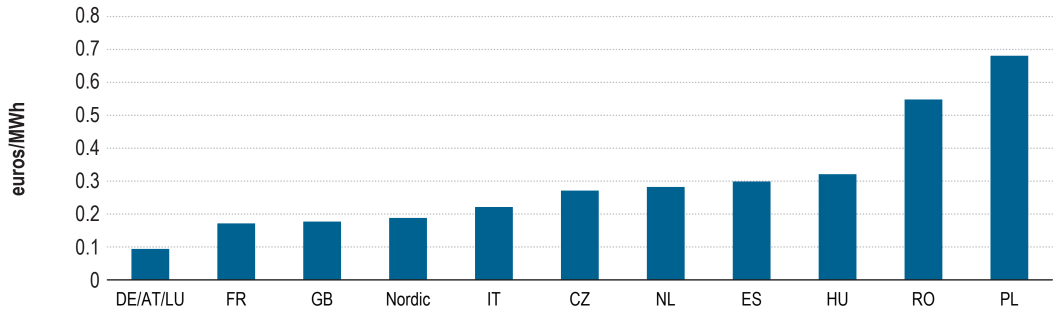


Source: European Power Trading 2017 report, © Prospex Research Ltd and NRAs (2018).

Note: The respective source for each market is the same as the one described in Figure 19. For the Czech Republic and Slovenia, disaggregated information on the forward market volumes provided in Figure 19 was not available.

172 Figure 21 presents the average bid-ask spreads of yearly base-load products (delivery in 2019) for a selection of European forward markets. It shows that the lowest average bid-ask spread is observed in the German/Austrian/Luxembourgish market, followed by the French, British and the Nordic markets. This confirms that these four forward markets are the most liquid in Europe, as also highlighted by the churn factor indicator.

Figure 21: Average bid-ask spreads (yearly product, 2019 delivery) in European forward markets – (euros/MWh)

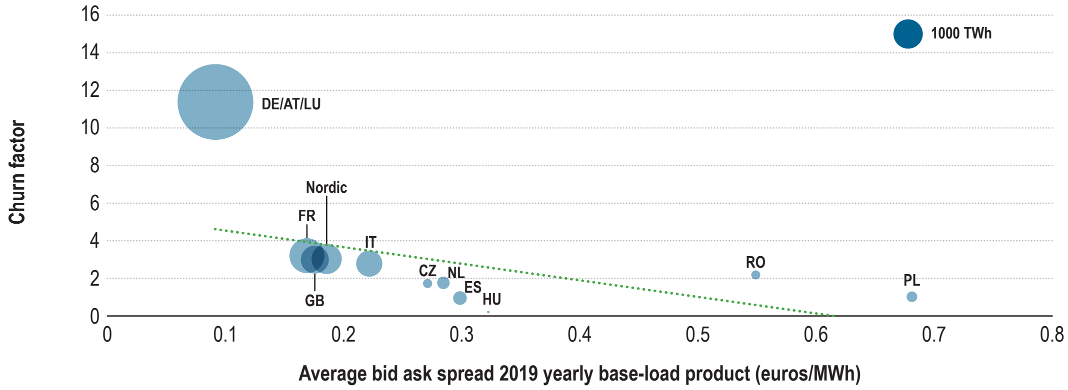


Source: ICIS (2018).

Note: The bid-ask spreads are averaged out throughout the period from July 2017 to June 2018. For Great Britain, the half-yearly (winter and summer 2019) products were used.

173 The relationship between the different measures of market liquidity used in this Section is illustrated in Figure 22, where forward market volumes, bid ask-spreads and churn rates are displayed together for the major European forward markets. Overall, the figure suggests a negative and moderate-to-high correlation between forward market volumes and bid-ask spreads. It also indicates that the transaction costs (which are related to the bid-ask spread size) incurred by market participants tend to be lower in bigger markets (when market 'size' is considered to be equivalent to traded volumes).

Figure 22: Forward market churn factors and volumes (2017) and average bid-ask spreads (yearly product, 2019 delivery) in European forward markets – (TWh and euros/MWh)



Source: NRAs, ICIS and European Power Trading 2018 report, © Prospex Research Ltd (2018).

Note: The bid-ask spreads are averaged out throughout the period from July 2017 to June 2018. The size of the bubbles is proportional to the absolute forward market volumes in respective markets.

174 In the context of the review process of bidding zone configurations (see Section 3.4), it is frequently argued that sufficiently large bidding zones are crucial to ensure adequate levels of forward market liquidity. However, in view of Figure 22, a direct correlation between the size of the bidding zones and the level of liquidity cannot be established.

175 On the one hand, the biggest bidding zone in Europe (Germany/Austria/Luxembourg) records the highest level of liquidity in forward markets. A similar observation can be made for other relatively large bidding zones such as France and Great Britain, which are among the forward markets with the highest liquidity. However, other relatively large bidding zones such as Spain or Poland record much lower levels of forward market liquidity[139]. The latter suggests that other factors, such as market concentration, the level of market integration or market maturity influence market liquidity more decisively.

176 On the other hand, in some geographical areas with relatively small bidding zones – as the Nordic area and, to a lesser extent, Italy – the level of forward market liquidity is among the highest in Europe. The forward markets in these two areas rely mainly on products linked to a unique 'hub' price used as a reference for all bidding zones within the respective (Nordic or Italian) area. This suggests that market design is also a decisive factor affecting forward market liquidity.

177 Finally, market participants located in relatively small bidding zones surrounding the German/Austrian/Luxembourgish bidding zone, such as in Belgium, Hungary, the Netherlands Poland, Romania and Slovenia, seem to struggle to find sufficient hedging opportunities. Transmission rights may mitigate this problem, but only to a certain extent (see footnote 136).

178 In view of this, it is recommendable to seek solutions that decouple liquidity from the size of the bidding zones, e.g. relying on multi-bidding-zones hedging instruments[140], as these would enable an equal access of market participants to hedging opportunities irrespective of their geographical location.

4.2 Intraday market liquidity

179 An efficient ID electricity market requires sufficient market liquidity, because it enables market participants' access to a larger portfolio of bids and offers to meet their balancing needs. Moreover, in the context of ongoing policy efforts to decarbonise European economies, a relatively high level of ID market liquidity is crucial for the optimal integration of variable generation from Renewable Energy Sources (RES) into the electricity market, which ultimately leads to welfare benefits for end consumers.

180 This Section has two parts. First, it provides an update on trends in the level of ID traded volumes throughout Europe over the past seven years. Second, it categorises the ID-traded volumes in 2017 according to a set of relevant criteria – including the nature of the trade and the trading time – by putting this analysis in the context of the design of the pan-European ID platform for the SIDC. The status quo of ID market liquidity in Europe prior to the go-live of the SIDC will serve as a basis for monitoring the effects of implementing the SIDC in the future, as required by the CACM Regulation.

4.2.1 Evolution of intraday-traded volumes

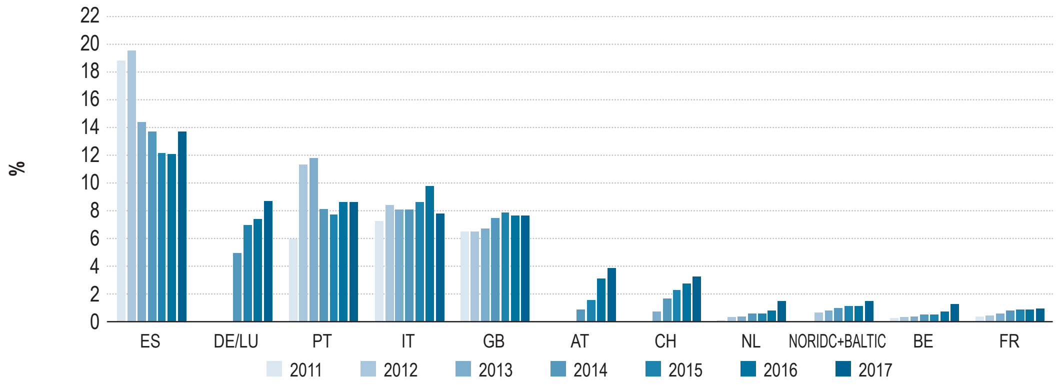
181 Although ID market volumes account for a relatively small fraction of overall demand in most areas, the upward trend in liquidity observed in recent years in most countries continued in 2017. This trend is consistent with the growing need for short-term adjustments due to the greater penetration of generation from variable RES into the electricity system.

139 In Spain, the churn ratio suggests relatively low liquidity, whereas in Poland, both the low churn ratio and the high bid-ask spread suggest low liquidity.

140 Other options such as the issuance of zone-to-zone financial transmission rights may be explored.

182 Figure 23 shows the ratio between ID-traded volumes[141] and electricity demand across the largest organised ID markets in Europe[142]. It illustrates that in 2017, Spain, Germany/Luxembourg, Portugal, Italy[143] and Great Britain continued to have the highest ID-traded volumes, expressed as a percentage of electricity demand.

Figure 23: Ratio between ID-traded volumes and electricity demand in the largest European ID markets – 2011–2017 (%)



Source: NEMOs, Eurostat, CEER National Indicators Database and ACER calculations (2018).
Note: Only markets with data available for at least four years are shown.

183 The relatively high level of ID-traded volumes in Spain, Italy and Portugal could be partially explained by three aspects that these markets have in common. The Spanish, Italian and Portuguese markets are characterised by high penetration of RES generation, the presence of exclusive ID auctions (i.e. no continuous trading and no alternative to organised market) and obligatory unit bidding. More precisely, electricity can be traded only in the organised ID market, and generators have to submit a separate market bid for each of their generating units, as opposed to portfolio bidding, where a market participant can send one bid for energy in a single bidding zone, covering all of its production assets and consumption needs in that zone[144].

184 Compared to 2016, the most notable relative increase in ID liquidity in 2017 was observed in Belgium (+77%), the Netherlands (+75%) and the Nordic and Baltic regions (+31%). In 2017, the increase in the Belgian and Dutch markets is partially explained by the introduction of an improved implicit ID cross-zonal capacity allocation platform[145] connecting the Dutch and Belgian markets with the French, German/Luxembourgish, Swiss and Austrian ID markets, which went live on 5 October 2016.

141 Throughout this Section, 'volume' refers to the average value between sell and buy volumes in a given bidding zone, unless specified otherwise. 2016 demand values were used as a proxy, instead of 2017 demand data (see footnote 108).

142 For the purpose of the analysis presented in this Section, the Agency collected quantitative data on ID markets in 2018 directly from 10 out of 15 Nominated Electricity Market Operators (NEMOs): BSP, CROPEX, EPEX SPOT, GME, Nord Pool, OKTE, OMIE, OPCOM, OTE and TGE. EirGrid/SONI, EXAA, HUPX, IBEX and LAGIE also provided information related to the intraday market structure. EirGrid/SONI, EXAA, IBEX and LAGIE were not requested to provide data for 2017, because products pursuant to the CACM Regulation were not tradable in these markets throughout the reporting year. In the context of Article 82 of the CACM Regulation, the Agency collected this data following an agreement with ENTSO-E setting the respective operational data collection responsibilities between the Agency and ENTSO-E.

143 The ID volumes reported for Italy in this report are slightly lower than the volumes reported by GME in its publications. The difference results from a different approach to aggregate the volumes. In particular, the ID volumes in this chapter are calculated as the aggregation of ID sell/buy volumes per bidding zone, therefore netting out the volumes traded across all auction rounds. This leads to a slight underestimation of the volume compared to the data reported by GME, in which the ID volumes are calculated as the sum of sell/buy volumes for each auction round.

144 For more information on the characteristics of the ID market design in a selection of European countries, see Table 16 in section '4.3.5. ID markets' (p. 198) of the MMR 2014, available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

145 Implicit allocation on these borders was already in place before this date, but the gate opening and closure times were not harmonised.

4.2.2 Categorisation of intraday-traded volumes

185 ID market liquidity is hardly predictable, but the go-live of the SIDC, as well as several of its market design features are expected to have a positive effect on ID liquidity across Europe in the future. In order to have a better overview of the trading activity in European ID markets in 2017 prior to the implementation of the SIDC, ID-traded volumes are categorised according to five criteria grouped into two overarching categories, as follows:

1) Categorisation of ID-traded volumes according to the nature of the trade:
    a. type of trading method (auctions vs. continuous trading);
    b. granularity of the product (length of the underlying market time unit); and
    c. cross-zonal vs. intra-zonal nature of the trade.

2) Categorisation of ID-traded volumes according to the trading time:
    a. time left until delivery, expressed as the number of hours between the time when the trade occurred and the start of delivery, i.e. relative trading time; and
    b. day and hour when the trade occurred on the day ahead of delivery (D-1) and on the delivery day (D), i.e. absolute trading time.

186 The remainder of this Section presents the potential impact of a series of market design features of the pan-European SIDC on ID market liquidity, based on the categorisation of ID-traded volumes according to the five above-mentioned criteria. The market design features discussed are, among others, the ID Cross-Zonal Gate Opening Time (IDCZGOT), the ID Cross-Zonal Gate Closing Time (IDCZGCT), the potential introduction of a pan-European ID auction (with one or more auction rounds) complementing the SIDC and the diversity of products offered for trade.

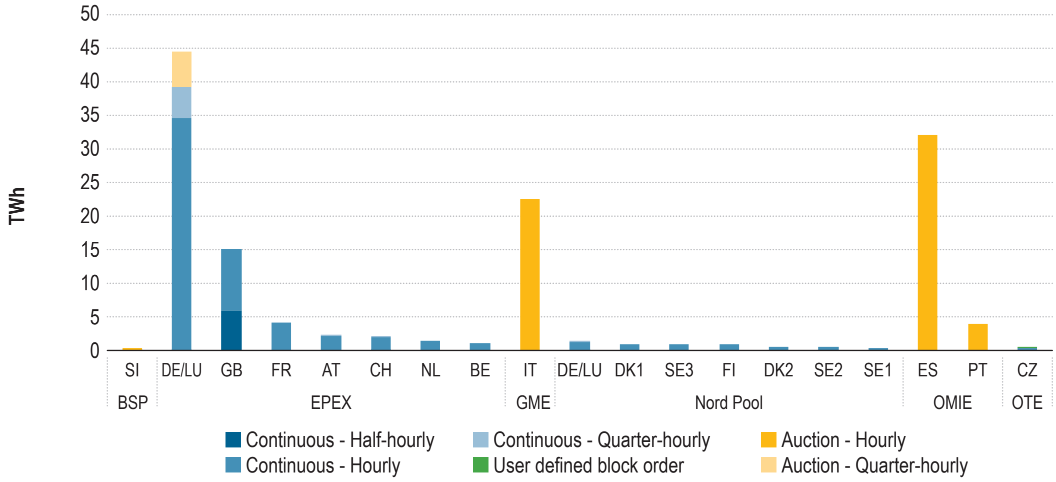
Categorisation of ID-traded volumes according to the nature of the trade (trading method, granularity and cross-zonal vs. intra-zonal nature of the trade)

187 Overall, the absolute volume of electricity traded on European power exchanges in the ID market timeframe amounted to 138 TWh in 2017. In 2017, the total ID-traded volume across European power exchanges was almost equally shared between auctions (47%) and continuous trading (53%). However, the results of the analysis show that the distribution of the absolute ID-traded volumes throughout Europe varies greatly, depending on the market and the trading method, but also the granularity of the product[146] offered for trading.

188 Figure 24 shows the ID-traded volumes in 2017 per market, categorised by type of product, i.e. depending on the trading method, granularity and whether trading is based on single or multiple contracts (block order). It illustrates that the largest markets according to the absolute ID-traded volumes in Europe are Germany/Luxembourg (46 TWh), Spain (32 TWh), Italy (23 TWh) and Great Britain (15 TWh), followed by France (4 TWh) and Portugal (4 TWh).

146 For the purpose of this analysis, a product is defined by three characteristics: i) the type of trading method (auctions vs. continuous trading), ii) the level of granularity, and iii) whether they are based on single contracts or block orders. Accordingly, the following types of products are considered: a) *hourly* products: 60 minutes, b) *half-hourly* products: 30 minutes, c) *quarter-hourly* products: 15 minutes, d) *predefined block-orders:* pre-defined combination of hourly, half-hourly or quarter-hourly blocks (e.g. combination of hourly products for base-load with delivery at 00:00-24:00) and e) *user-defined block orders:* market participants may combine hourly, half-hourly or quarter-hourly blocks (e.g. combination of three quarter-hourly blocks with delivery at 12:45-13:30).

Figure 24: ID-traded volumes per product, per bidding zone, in the largest European markets – 2017 (TWh)

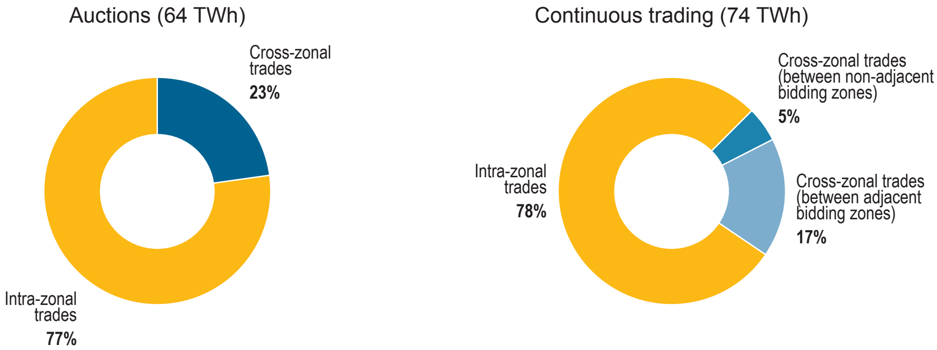


Source: NEMOs and ACER calculations (2018).

Note: This Figure contains data for the largest ID markets with average sell and buy volumes above 0.3 TWh (Table 6 in Annex 1 contains all data available). The data is presented in alphabetical order of the NEMO names and in descending order of the volumes per bidding zone.

189 In the context of ongoing efforts to create a more integrated electricity market, it is important to identify the intra-zonal and cross-zonal nature of ID-traded volumes. Figure 25 shows that, overall, in 2017, the share of ID-traded volumes that occurred between bidding zones accounted for less than one quarter of all the trades occurring in this timeframe, with no substantial differences between auctions and continuous trading, while the remaining share of trades were intra-zonal.

Figure 25: Share of total ID-traded volumes according to intra-zonal vs. cross-zonal nature of trades in Europe – 2017 (% of total ID-traded volume)



Source: NEMOs and ACER calculations (2018).

190 Moreover, of the total volume of 74 TWh traded continuously in 2017 in the ID market timeframe, 5% of ID-traded volumes occurred between non-adjacent bidding zones, i.e. between bidding zones that are not neighbouring each other (e.g. Germany/Luxembourg-Estonia), while 17% of trades occurred between adjacent bidding zones (e.g. France-Germany/Luxembourg). The remaining share of ID-traded volumes in the continuous market (78%) was intra-zonal.

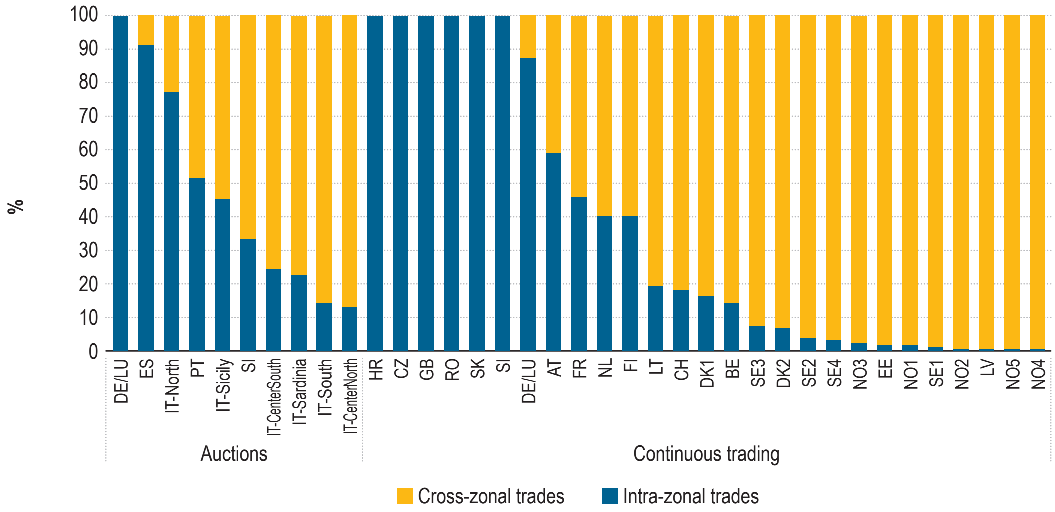
191 In this respect, the implementation of a SIDC with implicit continuous cross-zonal capacity allocation as of 12 June 2018, in line with the CACM Regulation, is expected to have two important effects on the ID market across Europe.

192 On the one hand, it is expected to increase the total ID-traded volumes at the European level, because the trading platform will accommodate the continuous matching of bids and offers from market participants in one bidding zone with bids and offers coming from its own bidding zone and from any other bidding zone to/from which cross-zonal capacity is available. As such, market participants will have access to a larger portfolio of bids and offers to meet their balancing needs, which is expected to increase the share of cross-zonal trades.

193 On the other hand, the share of ID-traded volumes between non-adjacent bidding zones is expected to increase, as cross-zonal trades between market participants located in two non-neighbouring bidding zones will be matched irrespective of their locations, provided that cross-zonal capacity is available between these bidding zones and the bidding zones having a transit role. As such, electricity would be traded in the ID market timeframe instantaneously across neighbouring and non-neighbouring bidding zones.

194 Furthermore, in 2017, the relative distribution between intra and cross-zonal trades varied greatly, depending on the market. Figure 26 shows the intra vs. cross-zonal nature of trades per type of trading method and per bidding zone, illustrating that seven nationally organised markets had purely intra-zonal trades. This was the case in Germany/Luxembourg for auctions and in Croatia, the Czech Republic, Great Britain, Romania, Slovakia and Slovenia for continuous trading[147]. Additionally, Figure 44 in Annex 1 shows the relative share of ID-traded volumes per NEMO, illustrating that, in 2017, BSP (auctions only), Nord Pool and GME were the NEMOs with the largest share of cross-zonal trades, with 83%, 80% and 37% of the total ID-traded volume, respectively.

Figure 26: Share of total ID-traded volume per type of trading method, per nature of trade, per bidding zone in Europe – 2017 (% of total ID-traded volume per bidding zone)



Source: NEMOs and ACER calculation (2018).

Note: Bidding zones are presented in descending order of the share of intra-zonal trades for each trading method.

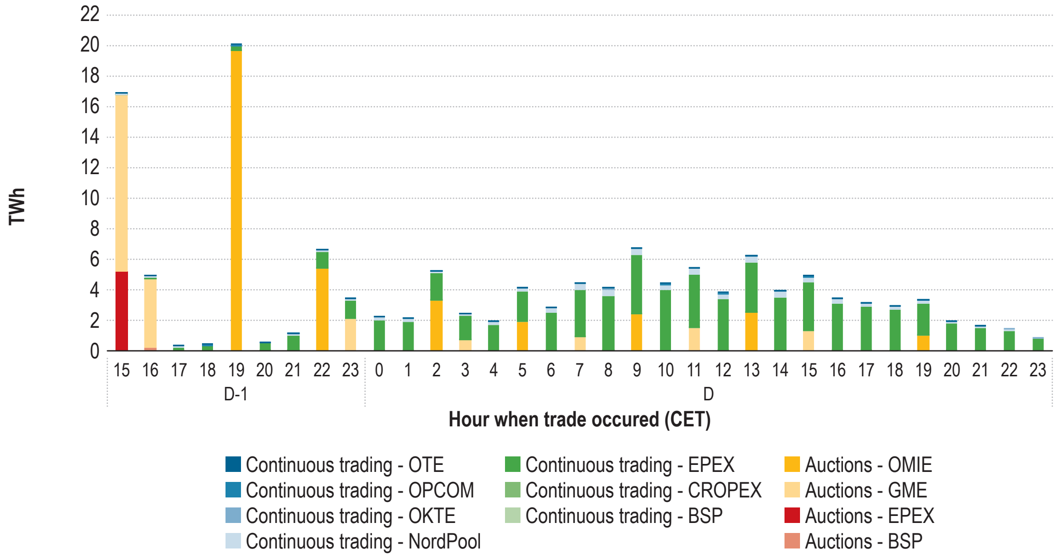
147 In these markets, cross-zonal trades are still possible, but it would require the explicit procurement of capacity. The data available for the present analysis does not allow the Agency to identify whether foreign traders procure a share of the intra-zonal volume.

Categorisation of ID-traded volumes according to trading time (time remaining until delivery vs. day and hour when the trade occurred)

195 One of the most important market design features of the SIDC is the IDCZGOT, because the sooner the IDCZGOT is set, the more opportunities for market participants to optimise their portfolios exist. For the time being, several IDCZGOTs are applied throughout Europe (see Table 7 in Annex 1), but the Agency's Decision No 04/2018 of 24 April 2018 sets an EU-wide harmonised IDCZGOT[148] to 15:00 Central European Time (CET)[149] on D-1, as of 1 January 2019, which is expected to have a positive impact on ID liquidity in the future. The extent to which the harmonised IDCZGOT will contribute to increase ID liquidity will depend largely on the ability of TSOs to release cross-border capacity at that point in time, including the release of more than the 'left-overs' of the DA market via a recalculation of ID cross-zonal capacity.

196 Figure 27 provides the full picture of liquidity throughout the EU in 2017 by showing the distribution of the total absolute ID-traded volumes, including both continuous trading and auctions in the current context of multiple national Gate Opening Times (GOTs) and non-harmonised IDCZGOTs. As of 31 December 2017, an important share of total ID-traded volume throughout the Continent was concentrated around auctions on D-1, while the volumes in continuous trading seem to be spread throughout the trading day D.

Figure 27: Distribution of total ID-traded volumes for continuous trading and auctions per trading hour (CET), per trading method and per NEMO in Europe – 2017 (% volumes per hour when trade occurred on trading day D-1 and D)



Source: NEMOs and ACER calculations (2018).

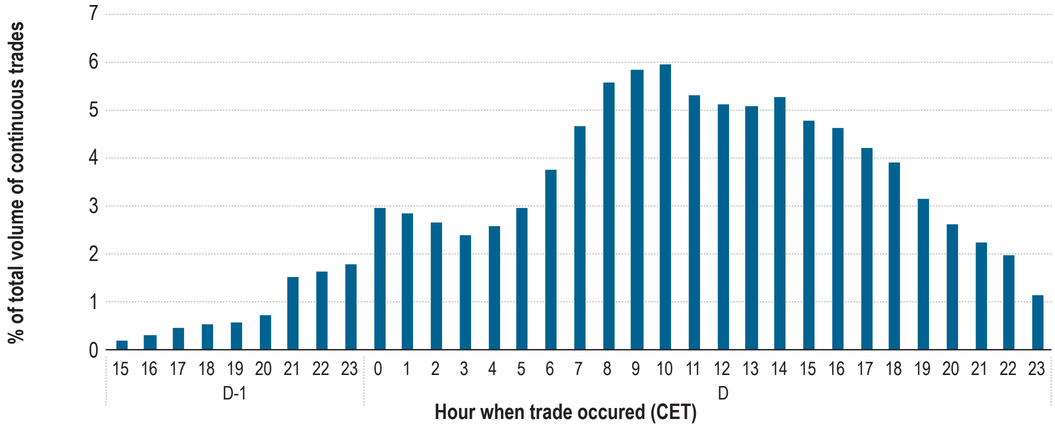
Note: Hour n refers to the time between hour n and hour n+1.

197 Furthermore, separate analysis of data per trading method provides additional insights into into the trading patterns in the ID market timeframe Figure 28 shows the distribution of total ID volumes throughout Europe for continuous trading only. It suggests that, at the European level, three trading peaks occur on the delivery day: one between 00:00-01:00 (CET), followed by one between 10:00 and 11:00 (CET) and another one between 14:00-15:00, while the remaining trades are spread throughout the delivery day around these peaks.

148 According to ACER Decision No 04/2018 of 24 April 2018 on all TSOs' proposal for IDCZGOT and IDCZGCT, the harmonised IDCZGOT should be applied as of 1 January 2019, or, in the event of delays in the approval of the relevant regional methodologies in a CCR, one month after the approval date in the respective CCR. The Decision is publicly available at: https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2004-2018%20on%20IDCZGTs.pdf.

149 Throughout this volume, CET refers indistinctly to CET and CEST.

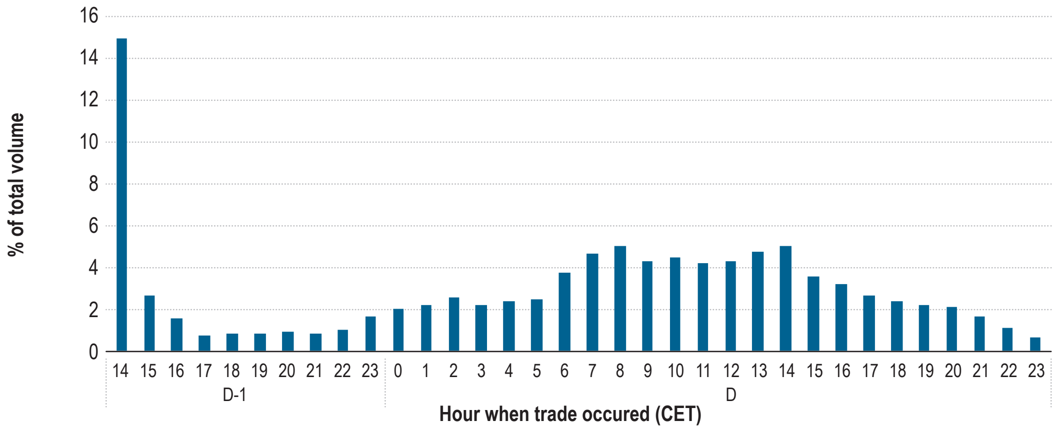
Figure 28: Distribution of total ID-traded volumes for continuous trading per hour (CET) in Europe – 2017 (% volumes of continuous trades per hour when trade occurred on trading day D-1 and D)



Source: NEMOs and ACER calculations (2018).
Note: Hour n refers to the time between hour n and hour n+1.

198 However, the above distribution is not representative of all markets with continuous trading, because the precise distribution of total ID-traded volumes for continuous trading varies greatly, depending on the bidding zone analysed. For example, the data presented in Figure 29 for Denmark East (DK2) for the hourly product with a relatively early national GOT which is set at 14:00 CET on D-1, illustrate the important liquidity concentration shortly after the GOT. In 2017, 15% of the total volume of the hourly product traded continuously in Denmark East was absorbed in the first trading hour, while the remaining volume was distributed throughout the entire trading period with more trading activity in the morning and early afternoon of the delivery day.

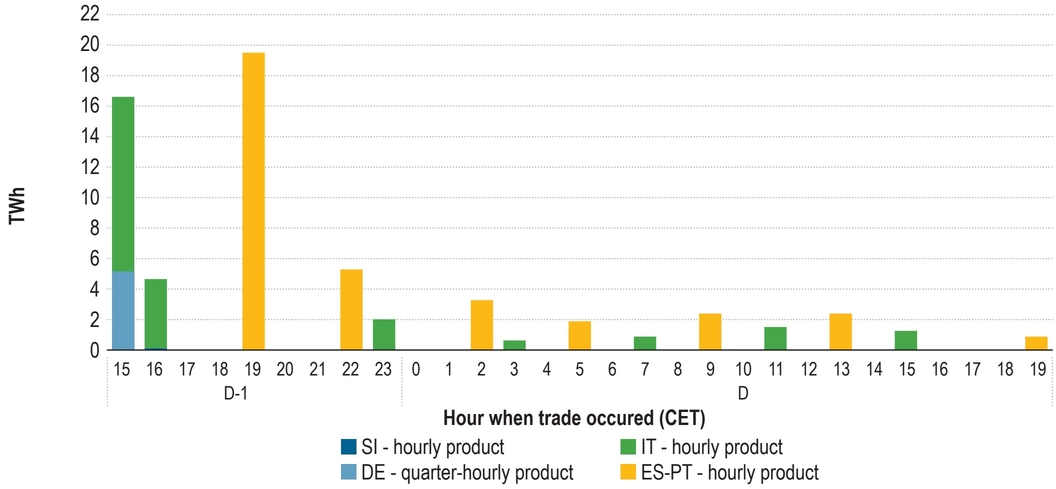
Figure 29: Distribution of ID-traded volumes per trading hour for the hourly product traded continuously in Denmark East – 2017 (% volumes per hour when trade occurred)



Source: NEMOs and ACER calculations (2018).
Note: Hour n refers to the time between hour n and hour n+1.

199 Similarly, Figure 30 shows the distribution of volumes per trading hour per product in European markets with auctions. In the Slovenian, Iberian and Italian markets, a large share of the total annual ID-traded volume (77%, 54% and 51%, respectively) was traded in the first of several auction rounds. In the German case, there is only one auction round for the quarter-hourly product, so 100% of the ID-traded volume for this product is concentrated at one point in time. Nevertheless, this analysis concludes that a large proportion of volumes are traded in the first auction round, regardless of the timing of such a round. This finding underlines that market participants value early trading opportunities in markets with multiple auction rounds.

Figure 30: ID-traded volumes per auction round (GCT) in all European markets with auctions – 2017 (TWh)

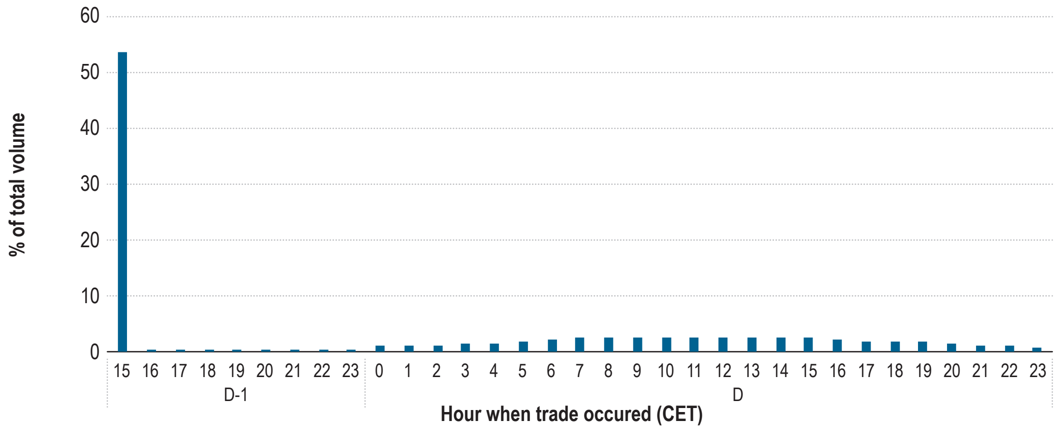


Source: NEMOs and ACER calculations (2018).

Note: This figure contains data on all European markets with auctions. The 'hour when trade occurred' corresponds to the full hour of the Gate Closing Time (GCT) for each auction round. For example, for the third auction round in Italy, which takes place between 17:30-23:45 (CET) on D-1, the ID-traded volumes corresponding to this auction round appear under hour 23 of D-1 in this figure. In the Iberian market, six auction rounds are held per day, but in the first auction round in which electricity is traded for the following day (D), it is possible to trade 27 hours (3 hours corresponding to D-1, and 24 hours corresponding to D). Italy has seven distinct auction rounds (see Table 7 in Annex 1 for the respective trading periods for each round).

200 In the context of ongoing debates regarding the future pan-European ID auction[150], assuming that this is a widely accepted way to price capacity to reflect market congestion, as required by Article 55(1) of the CACM Regulation, the following German example could provide some insights into the trading pattern of one product when two trading methods coexist[151]. Figure 31 shows the distribution of liquidity for the quarter-hourly product traded in 2017 in Germany via the two trading methods. In this market, which is characterised by a large penetration of RES, auctions attracted 54% of the total annual ID-traded volume for the quarter-hourly product, while the remaining share of 46% was traded continuously throughout the rest of the trading period.

Figure 31: Distribution of volume per trading hour for the quarter-hourly product (auctions + continuous trading) in Germany – 2017 (% volumes per hour when trade occurred)



Source: NEMOs and ACER calculations (2018).

Note: Hour n refers to the time between hour n and hour n+1.

150 On 14 August 2017, all TSOs submitted their common proposal for a single methodology for pricing intraday cross-zonal capacity to all NRAs. On 23 July 2018, all NRAs, after having agreed on a general view on the IDCZCP proposal, agreed to request the Agency to adopt a decision on IDCZCP pursuant to 9(12) of the CACM Regulation. Critical elements of an efficient design of the pan-European ID auction would be the number of auctions, the timing of (each of) the auction round(s), the degree of coordination between the ID auction and continuous trading, as well as the degree of coordination between the pan-European ID auction(s) and regional ID auctions.

151 This is the only market with intra-zonal trades where both auctions and continuous trading are used to trade the same product (i.e. quarter-hourly product).

201 Prior to the introduction of the quarter-hourly auction at 15:00 CET on D-1 in 2014, in Germany, liquidity was already concentrated at the beginning of the ID continuous market, whereby 5% of total ID-traded volumes in 2013 were traded in the first 15 minutes after the GOT[152]. This implies that the introduction of the quarter-hourly product auction was a response to an observed market need, which had as an effect, eventually, the reinforcement of liquidity concentration at one single point in time.

202 This example suggests that the following aspects are essential to ensuring the success of any future pan-European ID system to price ID capacity (e.g. an auction). First, the earliest possible opening of the market is recommendable, because market participants do value trading opportunities and transparent price-signals at the beginning of the ID market, even in situations where both auctions and continuous trading are in place for the same product. Accordingly, this example supports the case for a harmonised IDCZGOT as early as possible in order to limit the isolation of national ID markets during trading hours with relatively high liquidity. Second, this analysis suggests that in order to price capacity, e.g. via one or more pan-European ID auction rounds, setting the timing of such a system should take into consideration the points in time when liquidity is already high, because higher liquidity should contribute to pricing capacity more efficiently.

203 Another ID market design feature of utmost importance for the well-functioning of ID markets across Europe is the requirement laid down in the CACM Regulation to set the IDCZGCT to one hour at most before real time[153]. Following the Agency's Decision No 04/2018[154], the IDCZGCT for the Estonia-Finland bidding zone border will be 30 minutes (which is the preferred solution), while the IDCZGCT is harmonised at 60 minutes before the start of the relevant market time unit for all EU bidding zone borders participating in the SIDC.

204 In general, setting the IDCZGCTs closer to real time, subject to respecting the time needed for TSOs and market participants for their scheduling and balancing processes in relation to network and operational security, maximises opportunities for market participants to adjust their balances when more accurate information on the supply-demand balance is available. At the same time, it is expected to lead to higher liquidity levels, to reveal the real time value of electricity and to reduce the need for costlier balancing services.

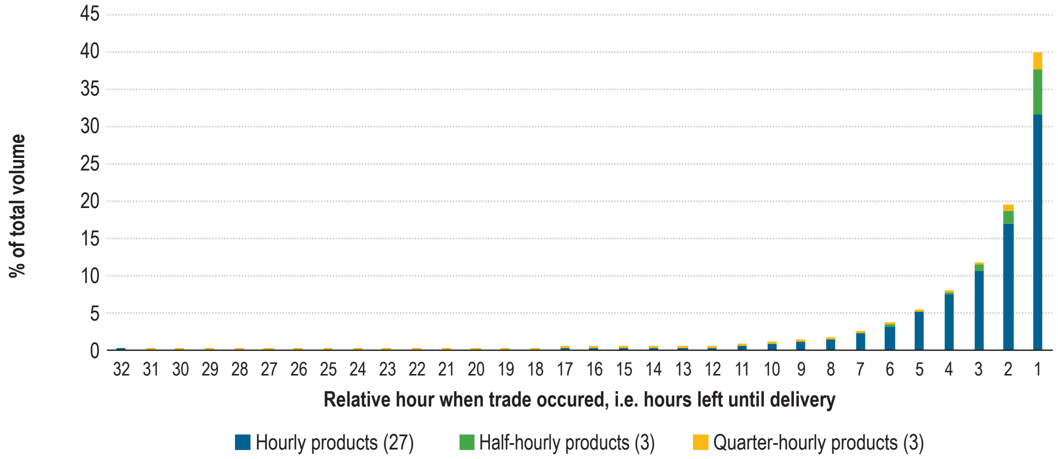
205 In this context, Figure 32 shows the distribution of volumes for three products traded in 2017 depending on the relative hour when the trade occurred, i.e. in relation to the number of hours that are remaining until physical delivery for a given market time unit. It includes the share of volumes for hourly, half-hourly and quarter-hourly products traded continuously on seven power exchanges throughout 2017. Overall, the largest shares of volume for these three products are traded between 1 and 2 hours before physical delivery, i.e. between 60 and 120 minutes before delivery. Moreover, 65%, 58% and 36% of the volume of the half-hourly, quarter-hourly and hourly products, respectively, were traded in the period of 60–120 minutes before delivery, which clearly shows that market participants prefer to trade as close as possible to real-time.

152 See, for example, the information sheet on the introduction of the quarter-hourly product auction in Germany, available at: https://www.epexspot.com/document/29113/15-Minute%20Intraday%20Call%20Auction.

153 National ID GCTs are also expected to be set at most one hour before real time. Currently, various GCTs are applied throughout national markets, ranging from 5 minutes before the beginning of physical delivery in Austria, Belgium, Germany/Luxembourg (in certain TSO areas), France and the Netherlands, up to 60 minutes in Great Britain and Switzerland or more, which is the case in Spain (135 minutes), Portugal (135 minutes) and Italy (195-540 minutes). See Table 7 in Annex 1 for a complete overview of the national GCTs applied in Europe as of 31 December 2017.

154 See Footnote 148.

Figure 32: Share of ID-traded volumes per relative trading hour for hourly, half-hourly and quarter-hourly products in implicit continuous markets – 2017 (% volumes of continuous trades per hour left until delivery)



Source: NEMOs and ACER calculations (2018).

Note: Hour 1 represents the trading interval between 60–120 minutes before the start of physical delivery. The number in brackets in the legend of the figure refers to the number of bidding zones included in the analysis for each traded product.

206 Another determining factor for the success of the SIDC in attracting liquidity at the pan-European level could be the diversity of products available for trade via this platform. Prior to the go-live of the XBID project, the variety of ID products offered expanded in nationally organised markets. For example, new ID products[155] were introduced in a number of nationally organised markets and borders, including the launch of 30-minute products for continuous ID trading in France, Germany and Switzerland on 30 March 2017.

207 At the go-live of the XBID project, all products traded continuously at the national level (hourly, half-hourly, quarter-hourly, pre-defined and user-defined blocks orders) in the MSs that have joined the project in the first phase, were also offered at the European level, ensuring no regression with respect to the situation prior to this date. For more information, Table 4 provides a complete overview of the products traded in all ID nationally organised markets across Europe (including those MSs that have not joined the XBID project in the first phase), as of 31 December 2017.

155 On 12 April 2018, Nord Pool introduced an hourly auction in Germany, with two rounds (one at 22:00 CET on D-1 and one at 10:00 CET on D). See press release, available at: https://www.nordpoolgroup.com/message-center-container/newsroom/exchange-message-list/2018/q2/nord-pool-intraday-auction-launches-in-germany/. On 10 July 2018, Epex Spot introduced quarter-hourly products for continuous trading in the Netherlands and Belgium. See press release, available at: http://static.epexspot.com/document/39304/20180712_EPEX_ECC_15-min_BE_NL_final.pdf. Half-hourly product auctions are also planned to be introduced in France.

Table 4: Overview of available ID products for trade per MS – 2017

	Auction			Continuous trading				
MS	Hourly	Half-hourly	Quarter-hourly	Hourly	Half-hourly	Quarter-hourly	Predefined block-order	User-defined block order
Austria	✗	✗	✗	✓	✗	✓	✗	✗
Bulgaria*	✗	✗	✗	✓	✗	✗	✗	✗
Belgium	✗	✗	✗	✓	✗	✗	✗	✗
Croatia	✗	✗	✗	✓	✗	✗	✓	✗
Czech Republic	✗	✗	✗	✓	✗	✗	✗	✓
Denmark	✗	✗	✗	✓	✗	✗	✗	✓
Estonia	✗	✗	✗	✓	✗	✗	✗	✓
Finland	✗	✗	✗	✓	✗	✗	✗	✓
France	✗	✗	✗	✓	✓	✗	✗	✗
Germany	✗	✗	✓	✓	✓	✓	✓	✓
Great Britain	✗	✗	✗	✓	✓	✗	✓	✓
Greece	✓	✗	✗	✗	✗	✗	✗	✗
Hungary	✗	✗	✗	✓	✗	✓	✓	✓
Ireland**	✗	✓	✗	✗	✗	✗	✗	✗
Italy	✓	✗	✗	✗	✗	✗	✗	✗
Latvia	✗	✗	✗	✓	✗	✗	✗	✓
Lithuania	✗	✗	✗	✓	✗	✗	✗	✓
Luxembourg	✗	✗	✓	✓	✓	✓	✓	✓
Netherlands	✗	✗	✗	✓	✗	✗	✗	✓
Norway	✗	✗	✗	✓	✗	✗	✗	✓
Poland	✗	✗	✗	✓	✗	✗	✗	✗
Portugal	✓	✗	✗	✗	✗	✗	✗	✗
Romania	✗	✗	✗	✓	✗	✗	✗	✗
Slovakia	✗	✗	✗	✓	✗	✗	✓	✓
Slovenia	✓	✗	✗	✓	✗	✓	✓	✓
Spain	✓	✗	✗	✗	✗	✗	✗	✗
Sweden	✗	✗	✗	✓	✗	✗	✗	✓
Switzerland	✗	✗	✗	✓	✓	✓	✗	✗

Sources: NEMOs (2018).

Note: See footnote 146 for the definitions of products used in this analysis. (*)The hourly product in Bulgaria was not yet tradable as of 31 December 2017. (**)The hourly product in Ireland is used to set cross-zonal capacity and interconnector schedules, which are settled ex-post.

208 Some general market design features are also expected to have a positive impact on ID liquidity, such as the extension of balancing responsibility to RES generators. As of 31 December 2017, RES generation was not treated in the same way as conventional generation regarding balancing responsibility in at least 11 MSs[156]. The Agency continues to advocate the full integration of electricity from RES in the wholesale market, which implies the removal of derogations to balancing responsibility and applying market-based principles to curtailments and redispatching.

209 Finally, yet importantly, some other aspects of the CACM Regulation potentially affecting ID liquidity are subject to regional agreement for the time being. This includes the possibility that continuous trading between and within bidding zones of the SIDC is complemented by regional ID auctions. This is subject to several conditions, including, inter alia, the absence of an adverse impact on the liquidity of the SIDC and the absence of undue discrimination between market participants from adjacent regions.

210 The approach to ensuring the compatibility of regional auctions with the SIDC differs across regions. In the Iberian market, following a public consultation in 2017, the Iberian regulators decided to implement the so-called 'model B', expected to go-live in late 2018, whereby continuous trading will be interrupted in order to hold regional auctions. The interruptions will lead to the temporary isolation of the ID Iberian market from the pan-European market, because continuous trading through the Spanish-French border will not be permitted. While

156 Austria, Croatia, Cyprus, France, Greece, Hungary, Italy, Lithuania, Malta, Portugal and the Netherlands.

the interruptions associated with this ‘model’ are a priori allowed, they should not have an adverse impact on the pan-European liquidity of the continuous trading system.

211 In the first semester of 2017, a public consultation on the interaction between the existing regional auctions and SIDC was also held in Italy. Based on the information available to the Agency, interruptions of continuous trading to hold regional auctions are not envisaged. However, ID auctions will be held regionally for each ID delivery period, before traders have the option to trade these delivery periods in the pan-European continuous market.

212 Without prejudice to the NRAs’ obligation to ensure that the design of regional ID auctions does not adversely impact liquidity or discriminate among market participants at European level, the Agency will monitor the evolution of liquidity in these markets with a focus on the interaction between regional auctions and the SIDC.

213 In conclusion, although the initial deadline for completing the IEM by 2014 set by the Council of the European Union was not met, the go-live of the XBID project establishing the SIDC as required by the CACM Regulation has been a major success. The present analysis constitutes a solid basis for monitoring the effects of implementing the SIDC throughout Europe in the future. While the effective application of the recently harmonised IDCZGOT at the EU level depends on when TSOs release capacity, other market design features are still undergoing public debates and the Agency will monitor their implementation in the future editions of the MMR.

5. Efficient use of available cross-zonal capacity

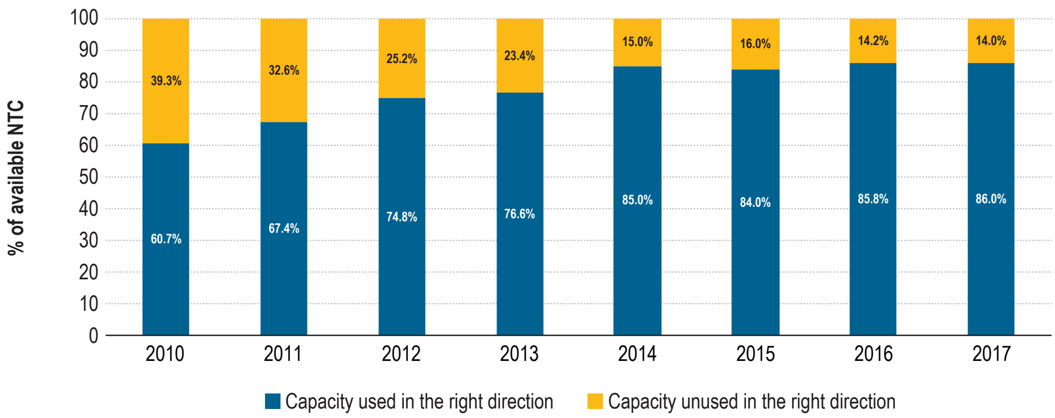
214 This Chapter reports on the progress made regarding the efficient use of existing cross-zonal transmission capacities in the DA (Section 5.1), ID (Section 5.2) and balancing (Section 5.3) market timeframes across Europe.

5.1 Day-ahead markets

215 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) in the presence of a price differential across a given border[157]. The progress already made towards market integration, as well as the potential progress to be made are illustrated by two indicators.

216 Figure 33 shows the progress made over the past eight years regarding the efficient use of electricity interconnectors in the DA market timeframe. For the purpose of this analysis, 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. This figure shows that, thanks to the DA market coupling of two thirds of European borders, covering 23 European countries[158] by the end of 2017, the level of economic efficiency in the use of interconnectors in this timeframe increased from approximately 60% in 2010 to 86% in 2017. Between 2016 and 2017, the level of efficiency in the use of electricity interconnectors throughout Europe remained essentially unchanged as there was only one relevant improvement in DA capacity allocation in Europe over the past two years, which was the extension of DA market coupling to the Austrian-Slovenian border in July 2016.

Figure 33: Progress made in the efficient use of electricity interconnectors in the DA market timeframe over the last 8 years – percentage of available capacity (NTC) used in the 'right direction' in the presence of a significant price differential (>1 euro/MWh) on 37 European electricity borders – 2010 (Q4)–2017 (%)



Source: ENTSO-E, Vulcanus, Nord Pool and ACER calculations (2018).

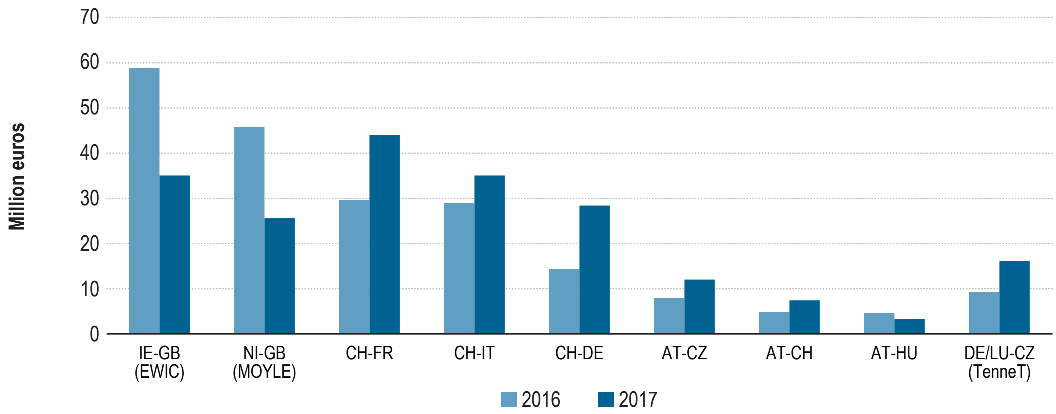
217 On non-coupled borders, the level of efficient use of cross-zonal capacity remained essentially unchanged, as this level depends mainly on the ability of traders to forecast price differentials. In particular, one of the main challenges for completing the internal electricity market in the DA market timeframe throughout Europe remains the integration through FBMC of Croatia, the Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia to the remaining markets of the overarching Core region, which is essentially a merge of the former CWE and CEE regions.

157 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_Public/ACER%20Methodological%20paper%20-%20Benefits%20from%20day-ahead%20and%20intraday%20market%20coupling.pdf.

158 By the end of 2017, DA market coupling had been implemented on 30 out of 42 EU borders (excluding the four borders with Switzerland), covering Austria, Belgium, the Czech Republic, Germany, Denmark, Estonia, Finland, France, Great Britain, Hungary, Italy, Lithuania, Latvia, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Spain, Slovenia, Slovakia and Sweden. Additionally, Bulgaria and Croatia are full members of the commercial Multi-Regional Coupling (MRC) project, and connected to the MRC calculation via the common PCR algorithm (Euphemia), but without interconnector capacities.

218 Over the past eight years, thanks to DA market coupling, EU consumers have reaped significant welfare benefits. Nevertheless, Figure 34 shows that the overall estimated 'loss in social welfare' due to the absence of market coupling on borders that still applied explicit DA auctions by the end of 2017 amounts to over 208 million euros per year. Among the non-coupled borders[159], the largest social welfare gains could be still obtained on all Swiss borders with the EU and on the British borders with Ireland and Northern Ireland.

Figure 34: Estimated social welfare gains still to be obtained from further extending DA market coupling per border – 2016–2017 (million euros)



Source: ENTSO-E, NRAs, Vulcanus and ACER calculations (2018).

Note 1: Only non-coupled borders are shown. The borders within the Core (CEE) region with 'multilateral' technical profiles are not included in this figure, because the methodology applied to the other borders, based on NTC values, is not applicable to these Core (CEE) borders for this calculation. Figure 45 in Annex 1 shows that cross-zonal capacity was underutilised in 2017 on those borders (DE/LU-CZ, DE/LU-PL, PL-SK), as they were affected by 'wrong-way flows'.

Note 2: IE-GB (EWIC) refers to the East-West Interconnector, which links electricity transmission grids of Ireland and Great Britain, and NI-GB (MOYLE) refers to the Moyle Interconnector, which links electricity grids of Northern Ireland and Great Britain. The difference observed between 2016 and 2017 for these two borders could be partially explained by: 1) missing NTC values on ENTSO-E's TP for 9 months (March-November 2017), which was addressed in this analysis by extrapolating the social welfare gains to the remaining months of the year, and 2) the DA price reference for Ireland changed (see more information in the note under Table 5 in Annex 1).

219 Despite the aforementioned modest progress in the completion of DA market coupling in 2017, several other DA market coupling projects started in that year, which are expected to improve the economic efficiency of interconnectors in this market timeframe at the European level. For example[160], the following projects are planned to be implemented in 2018: the introduction of capacity calculation on the Austrian border with Germany/Luxembourg[161]; the coupling of the Slovenian-Croatian, Italian-Greek, British-Irish (SEM)[162] borders; the implementation of the Western Balkans 6 (WB6) project, which is eventually intended, among other things, to integrate the DA markets in Albania, Bosnia and Herzegovina, Kosovo*, the Former Yugoslav Republic of Macedonia, Montenegro and Serbia, through neighbouring countries, to the pan-European DA market[163]. While the testing of the market coupling project covering the Swiss borders was completed in 2014, the implementation is on hold due to ongoing broader political discussions between Switzerland and the EU.

159 The remaining 13 non-coupled EU bidding zone borders are: AT-CZ, AT-HU, BG-GR, BG-RO, CZ-DE, CZ-PL, DE-PL, GR-IT, PL-SK, IE-GB, NI-GB, HR-SI and HR-HU.

160 For further information on the status quo of DA market coupling projects, see ENTSO-E's 'First joint report on the progress and potential problems with the implementation of intraday and day-ahead coupling as well as forward capacity allocation', available at: https://docstore.entsoe.eu/Documents/Network%20codes%20documents/NC%20CACM/First_Joint_Report_FCA_and_CACM.PDF.

161 Pursuant to ACER Decision 06-2016 on CCRs (see footnote 40).

162 See footnote 45.

163 Energy Ministers committed their countries to regional market coupling and a regional balancing market. As a follow-up, on 27 April 2016, the WB6 TSOs concluded a Memorandum of Understanding on regional electricity market development and establishing a framework for other future collaboration, which is available at: https://www.energy-community.org/dam/jcr:231f274d-4ecf-4017-a9f0-71aea1a7e41f/MoU_WB6.pdf.

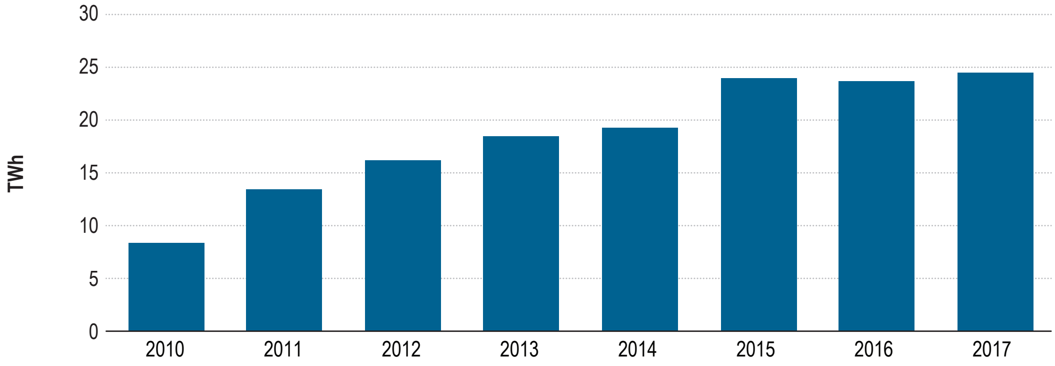
220 In conclusion, DA market coupling of non-coupled borders remains a crucial outstanding element in the integration of European electricity markets. The efficient use of interconnectors increased significantly over the past eight years due to DA market coupling across Europe, but the persistently high social welfare gains which could be obtained from implicit DA capacity allocation methods reaffirm the urgency of finalising the implementation of DA market coupling, as required by the CACM Regulation, on all remaining European bidding zone borders that were still applying explicit DA auctions at the end of 2017.

5.2 Intraday markets

221 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[164] by analysing 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).

222 Figure 35 shows that, in absolute terms, aggregated cross-zonal volume nominated in the ID market timeframe across the European network tripled between 2010 and 2017. Between 2016 and 2017, cross-zonal ID nominations increased by 3%. This upward trend in nominations is consistent with the increase in ID-traded volumes observed in most of the MSs over the past eight years (see also Section 4.2).

Figure 35: Absolute sum of net ID nominations for a selection of EU borders – 2010–2017 (TWh)



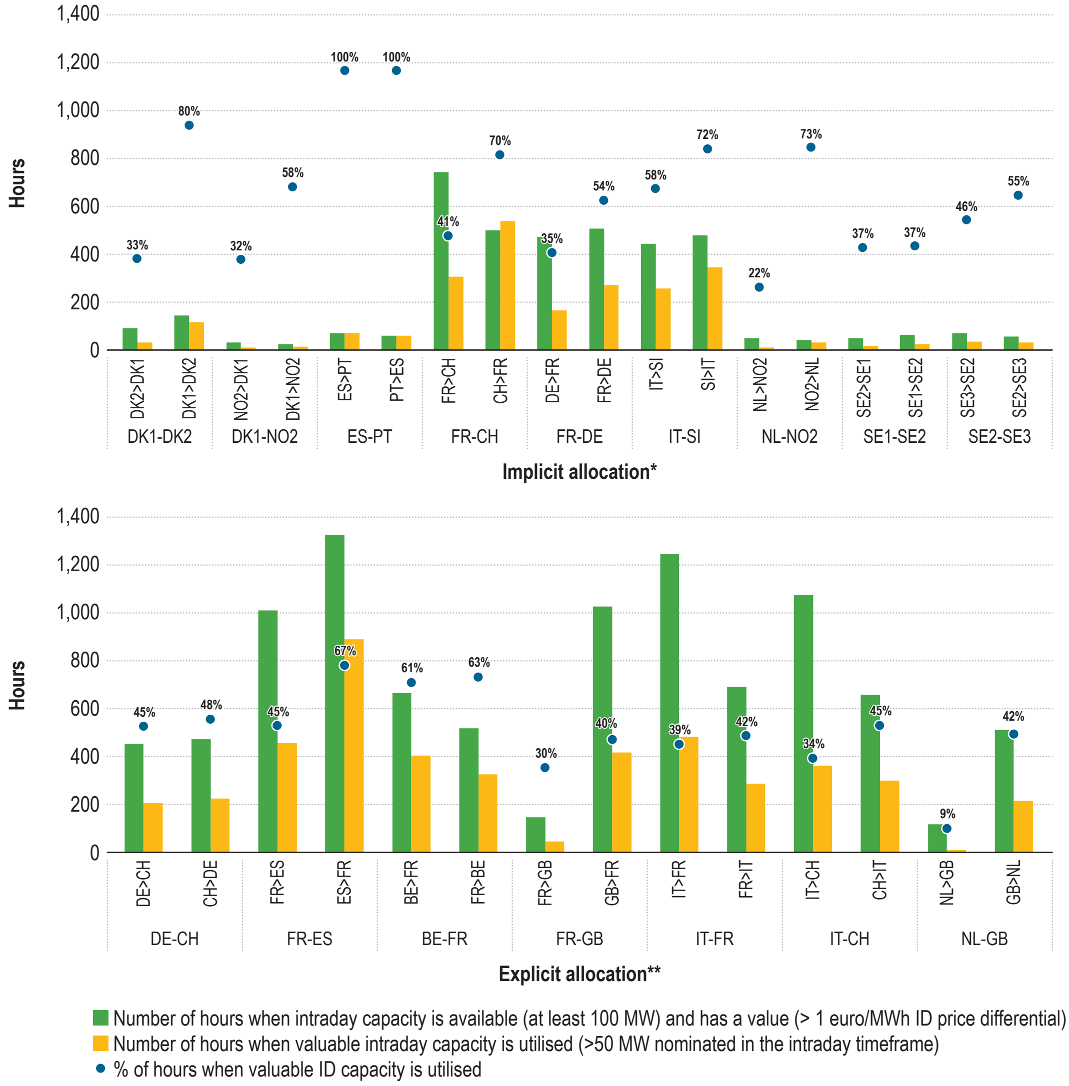
Source: ENTSO-E, NRAs, Vulcanus and ACER calculations (2018).

Note: This figure contains data for those borders for which data was consistently available for the period analysed, i.e. AT-DE, AT-SI, BE-FR, BE-NL, CH-DE, CH-FR, CH-IT, CZ-SK, CZ-DE, DE-FR, DE-NL, DE-PL, ES-FR, ES-PT and FR-IT.

223 Figure 36 shows the level of utilisation of cross-zonal capacity in the ID market timeframe, when capacity has a value (>1 euro/MWh) for a selection of borders in Europe, both for implicit and explicit capacity allocation methods. Compared to previous years, this analysis was extended to cover 16 borders with the respective border directions.

164 See footnote 157.

Figure 36: Level of utilisation of cross-zonal capacity in the ID timeframe when it has a value, for a selection of borders – 2017 (hours)



Source: ENTSO-E, NRAs, Vulcanus and ACER calculations (2018).

Note: In some markets, ID liquidity (ID-traded volumes) is relatively low. Therefore, a threshold for ID-traded volumes of 50 MWh was used for this analysis. Moreover, only borders with a minimum of 10 hours with available and valuable capacity were included in this figure. The percentages indicate the share of hours when capacity is used in the right direction (at least 50 MW used) with ID price differentials of at least 1 euro/MWh and sufficient availability of cross-zonal capacity (at least 100 MW). Only those hours with at least 50 MW of ID liquidity on both sides of the border were considered. The threshold for the ID price differential was raised to 2 euros/MWh for borders applying loss factors, i.e. the Netherlands-Norway, France-Great Britain and the Netherlands-Great Britain. (*) The French-German border features both implicit continuous and explicit OTC capacity allocation. (**) On 5 October 2016, a new implicit ID cross-zonal capacity allocation platform went live, connecting the Dutch and Belgian markets with the French, German, Swiss and Austrian ID markets.

224 First, Figure 36 shows that, despite the increasing trend of ID-traded volumes and cross-zonal nominations in the ID market timeframe, the efficiency[165] of the utilisation of ID cross-zonal capacity remains relatively low (on average 50% in 2017), especially when compared to the DA market timeframe (on average 86% in 2017).

165 For the purpose of this analysis, the most representative prices are provided by the closest-to-real-time trades, since they are considered better for revealing the value of cross-zonal capacity at the time when final cross-zonal nominations are determined. Where ID markets are auction-based, closest-to-real-time trades can be valued at the price of the last auction for every delivery hour. Where ID markets are based on continuous trading, the weighted average ID prices can be used as a proxy for the value of the closest-to-real-time trades. See more details in Sub-section 3.3.1 on 'Utilisation of cross-zonal capacity in the ID and balancing timeframes' (p. 126) of the MMR 2013, available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2014.pdf.

225 Second, this analysis confirms that cross-zonal capacity was allocated more efficiently by using implicit allocation methods (60% efficiency) rather than explicit or other allocation methods (47% efficiency). Another insight from the analysis presented in Figure 36 is that in 2017 cross-zonal capacity was used more efficiently in the ID market timeframe on borders which applied implicit auctions (100% efficiency for the Spanish-Portuguese border), compared to borders with implicit continuous trading (50% efficiency).

226 Furthermore, although this cannot be directly deducted from the Figure 36 displayed in this Section, the analysis performed concluded that the level of efficiency is higher on the Spanish-Portuguese border where capacity allocation is performed exclusively via implicit auctions, compared to the Italian-Slovenian border where implicit auctions coexist with continuous trading. Nevertheless, the analysis of the ID efficiency at hourly level on the Italian-Slovenian border showed that capacity is allocated efficiently for delivery hours 16 (border direction IT-SI) and 17 (border direction SI-IT), which could be explained by the fact that the GCT of the second auction round on D-1 where Slovenian traders participate in the Italian auctions is very close to these delivery hours[166]. The level of efficient utilisation of cross-zonal capacity reached 100% during these hours, decreasing progressively in the subsequent hours.

227 Overall, this analysis suggests that a large 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[167]. However, the materialisation of the SIDC through the XBID project on 12 June 2018 is expected further to increase the economic efficiency in the use of cross-zonal capacity in the ID timeframe. Developments regarding the impact of the SIDC on the efficient use of existing infrastructure in the ID market timeframe will be monitored by the Agency in future editions of this MMR.

5.3 Balancing markets

228 This Section provides an update on the prices of balancing services (energy and capacity) (Sub-section 5.3.1) and on the scope for a further exchange of these services across EU borders (Sub-section 5.3.2).

5.3.1 Balancing (capacity and energy)

229 While in 2017, large disparities in balancing energy and balancing capacity prices persisted in Europe (see Figure 46 and Figure 47 in Annex 1), the projects to increase the exchange of balancing services across borders initiated in recent years have started to bear fruit. An example of these initiatives is the Frequency Containment Reserves (FCR) cooperation, a common market for the procurement and exchange of balancing capacity, which currently involves ten TSOs in seven countries[168]. Figure 37 shows that, since 2014, balancing capacity prices have been steadily decreasing and converging across the markets involved in the FCR cooperation project.

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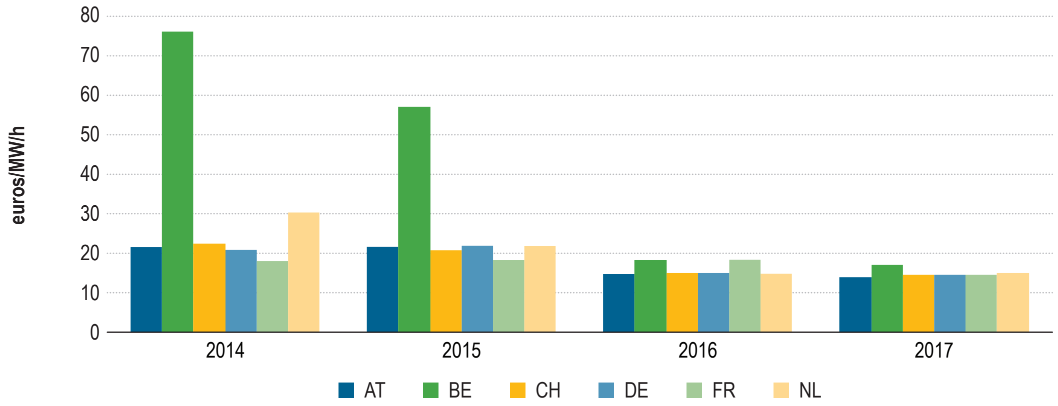
166 In addition to the existent implicit continuous trading mechanism between Italy and Slovenia, Slovenian traders participate implicitly to the second and sixth Italian auction rounds (i.e. MI2 and MI6).

167 For the methodology underlying this estimation, 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_Public/ACER%20Methodological%20paper%20-%20Benefits%20from%20day-ahead%20and%20intraday%20market%20coupling.pdf. 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.

168 These are 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).

Figure 37: Average prices of balancing capacity (from FCRs) in the markets involved in the FCR cooperation project – 2014–2017 (euros/MW/h)

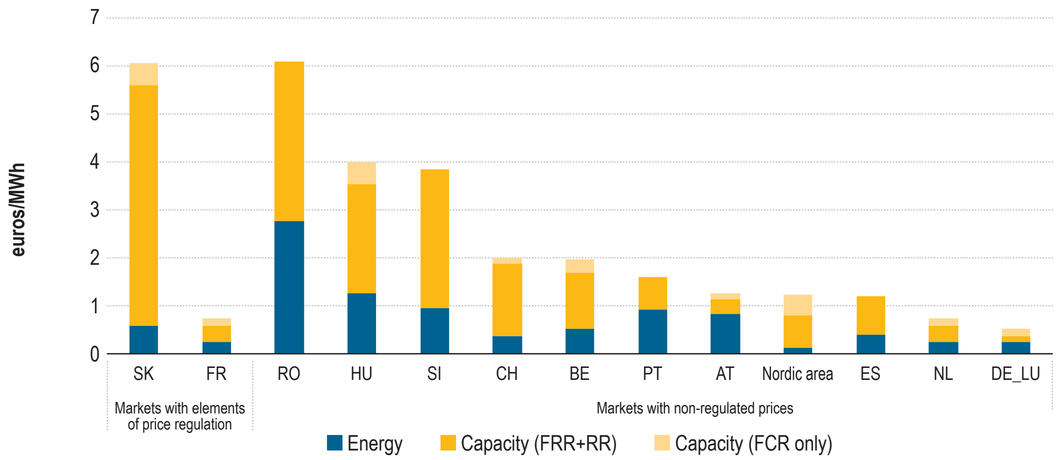


Source: NRAs and ACER calculations (2018).

Note: The prices refer to the joint procurement of 1 MW upward and 1 MW downward capacity when the product is symmetric or to the sum of prices to procure 1 MW upward and 1 MW downward capacity when the products are procured separately. Western Denmark is not shown in the figure, as it had not yet joined the project by the end of 2017.

230 The efficiency gains result in a reduction of the overall costs of balancing services that are ultimately borne by final consumers. The overall costs of balancing compared to electricity demand in a selection of EU markets are displayed in Figure 38.

Figure 38: Overall costs of balancing (capacity and energy) over national electricity demand in a selection of European markets – 2017 (euros/MWh)



Source: NRAs and ACER calculations (2018).

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.

231 Compared to 2016, no significant changes in the overall costs of balancing were observed. 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.

5.3.2 Cross-zonal exchange of balancing services

232 An integrated cross-zonal balancing market is intended to maximise the efficiency of balancing by using the most efficient balancing resources while safeguarding operational security. In fact, the efficient exchange of balancing services is the core element of the recently adopted EB Guideline[169], which provides the legal framework for integrating national balancing markets.

233 Figure 39 and Figure 40 show, respectively, the share of activated balancing energy and of balancing capacity (for FCRs) procured cross-border, compared to system needs in 2017. Additionally, Figure 41 shows the application of imbalance netting as a percentage of the total needs for balancing energy.

Figure 39: EU balancing energy activated cross-border as a percentage of the amount of total balancing energy activated to meet national needs – 2017 (%)

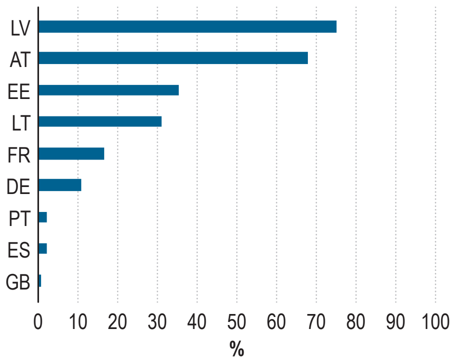
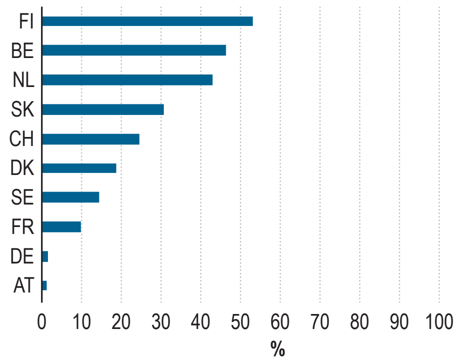


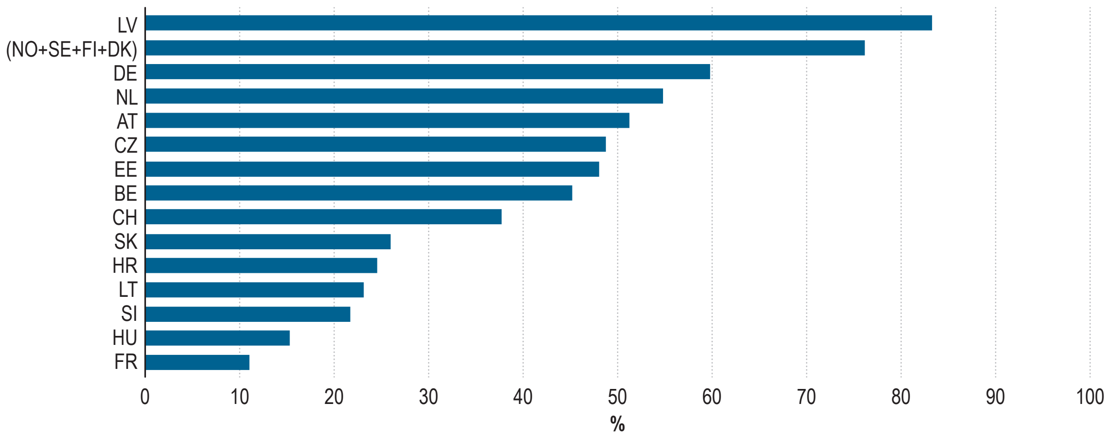
Figure 40: EU balancing capacity contracted cross-border as a percentage of the system requirements of reserve capacity (upward FCRs) – 2017 (%)



Source: NRAs and ACER calculations (2018).

Note: These figures include only the countries that reported some level of cross-zonal exchange. The actual exchange of balancing energy across borders within the Nordic region is not included in Figure 39, 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. Instead, they are reported together in Figure 41 .

Figure 41: 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 – 2017 (%)



Source: NRAs and ACER calculations (2018).

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 for the Nordics is the sum of the percentages of imbalance netting and exchanged balancing energy, which cannot be disentangled.

169 See footnote 21.

234 When compared with the equivalent figures included in preceding MMRs, Figure 39, Figure 40 and particularly Figure 41 illustrate that the exchange of balancing services is covering an increasing share of the balancing needs in several countries. A paradigm of a successful exchange of balancing services is the utilisation of imbalance netting across borders, which covers more than half of the needs of balancing energy in several European markets, including Latvia, Germany, the Netherlands and Austria where imbalance netting avoided 83%, 60%, 55%, and 51% respectively, of the electricity system's balancing energy needs in 2017. In the Nordic region, the combined application of imbalance netting and cross-zonal exchange of balancing energy covered around 76% of the electricity system balancing energy needs in 2017[170].

235 As mentioned in the previous Section, this improvement is largely due to several initiatives intended to support the implementation of the EB Guideline. The most relevant pilot projects related to these initiatives are briefly described below.

236 First, the FCR cooperation project, already mentioned in the previous Sub-section (for the countries involved, see footnote 166), which relies on a TSO-TSO-model[171], where the FCR is procured through a common merit order list where all TSOs pool the offers they receive from the balancing service providers (BSPs) within their respective areas of responsibility. Some of the challenges ahead for this project are extending it to a larger geographical area and evolving from weekly to daily procurement in order to comply with the EB Guideline.

237 Second, the imbalance netting cooperation pilot projects, which includes the International Grid Control Cooperation (IGCC)[172], the e-GCC[173] and the Imbalance Netting Cooperation (INC)[174] projects. To establish a European process to operate the imbalance netting process in compliance with the EB Guideline, TSOs have agreed to use the IGCC as a reference project.

238 Third, the Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)[175] is considered as the starting point for implementing and operating a platform for automatically-activated Frequency Restoration Reserves (aFRRs), in compliance with the EB, CACM and SO Guidelines. Previous aFRR cooperation projects in participating countries are part of PICASSO and considered to be interim steps on the way to the target design; one example is the existing aFRR cooperation between Austria and Germany[176].

239 Fourth, an initiative to design a platform for exchanging balancing energy from manually-activated frequency restoration reserves (mFRRs) was launched in April 2017 with the signing of a memorandum of understanding by 19 European TSOs. The project is officially named the Manually Activated Reserves Initiative (MARI).

240 Last, among the projects intended to exchange balancing energy from RRs, the TERRE project was selected by ENTSO-E as the one to become the European platform for the exchange of balancing energy from RRs pursuant to the EB guideline.

170 The application of imbalance netting and cross-border exchange of balancing energy cannot be disentangled in the Nordic region for the reasons set out in the note under Figure 41.

171 'TSO-TSO model' means 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.

172 The IGCC is a regional project operating the imbalance netting process which currently involves 11 TSOs in 8 countries. These are the TSOs in Austria (APG), Belgium (Elia), Switzerland (Swissgrid), the Czech Republic (CEPS), Germany (50Hertz, Amprion, TenneT DE, TransnetBW), Denmark (Energinet.dk), France (RTE) and the Netherlands (TenneT NL).

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

174 The INC is a project operating the imbalance netting process which involves APG (Austria), ELES (Slovenia) and HOPS (Croatia).

175 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 and Svenska Kraftnät.

176 The aFRR-cooperation project involving the German and Austrian TSOs went live on 14 July 2016. The cooperation allows 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.

241 Overall, some of these pilot projects are currently operational and are already yielding benefits by increasing the efficiency and competition levels of the various balancing services. The main challenges ahead related to these projects are i) widening their geographical scope to enable the participation of all European TSOs and ii) aligning the underlying rules and procedures with the requirements of the EB Guideline.

242 Finally, 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[177], the actual application of imbalance netting and exchange of balancing energy is estimated at approximately 22% of their potential in 2017 for a selection of 13 borders where sufficient information was available. Although this value indicates a slight improvement (between 2% and 3%) compared to the previous year, it is still relatively low when compared to the level of efficiency recorded in the preceding DA (86%) and ID (50%) timeframes in 2017. 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[178].

6. Capacity mechanisms and generation adequacy

243 MSs have a legitimate interest to ensure security of supply in their countries at all times, which is increasingly challenging in a context of greater RES penetration. In response to this challenge, an increasing number of MSs have already implemented or decided to implement a capacity mechanisms. These CMs are mostly being planned or introduced in an uncoordinated manner, which may be detrimental to market integration. However, in an integrated European energy market, security of supply should no longer be an exclusive national consideration, as more coordination in this area should contribute to achieving the desired levels of security of supply at a lower cost for end consumers.

244 This Chapter first presents an update on the situation of CMs in Europe, including their impact on end-consumers' electricity bills (Section 6.1). Second, it provides an update on how the contribution of interconnectors is taken into account in national generation adequacy assessments, which are often used as a basis to determine whether to implement a CM, and presents the potential benefits from more coordinated adequacy assessments (Section 6.2).

177 See methodological paper on 'Benefits from balancing markets integration', available at: https://www.acer.europa.eu/en/Electricity/Market%20monitoring/Documents_Public/ACER%20Methodological%20paper%20-%20Benefits%20from%20balancing%20markets%20integration.pdf.

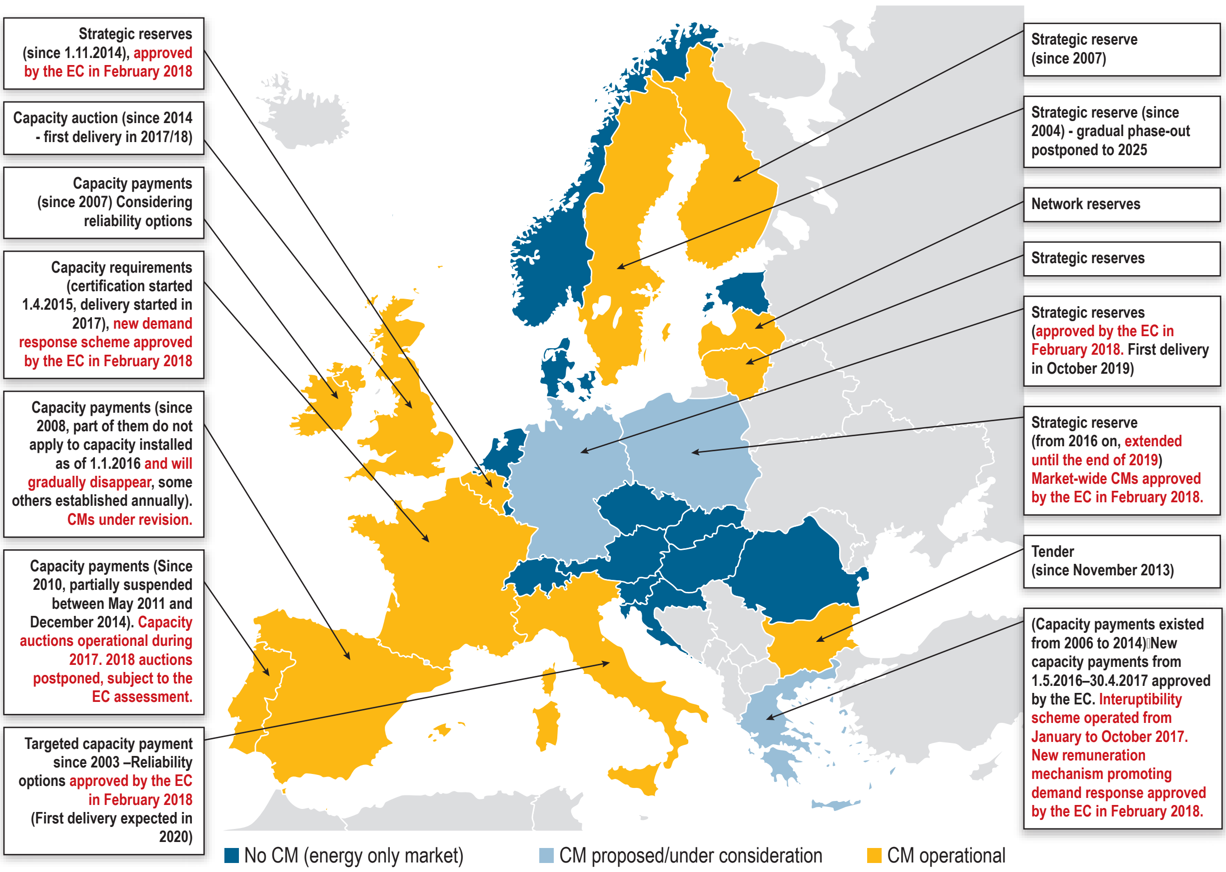
178 See footnote 177 and paragraph 582 of the Electricity Wholesale Markets Volume of the MMR 2014.

6.1 Situation in capacity mechanisms

245 Figure 42 presents the situation of the different types of CMs and their stage of implementation in Europe at the end of 2017, although the Figure also reflects the most recent developments on this matter in early 2018. In fact, the key changes compared to last year relate to the EC's approval of six electricity CMs to ensure security of supply in Belgium, France, Germany, Greece, Italy and Poland in February 2018.

246 The six approved CMs adopt three different structures. For Belgium and Germany, the EC authorised strategic reserves, whereby certain generation capacities are kept outside the electricity market for operation only in emergencies. For Italy and Poland, the EC authorised market-wide CMs, whereby companies are offered payments to generate electricity or reduce their electricity consumption. In the case of France and Greece, the Commission authorised demand response schemes, whereby customers are incentivised to reduce their electricity consumption in hours where electricity is scarce. In other markets (e.g. in Portugal or Spain), the CMs are undergoing a revision.

Figure 42: CMs in Europe – 2017



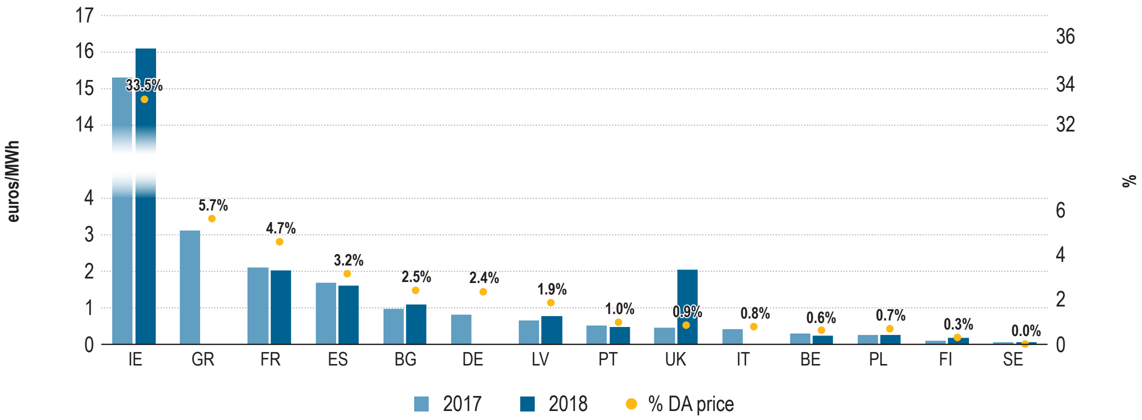
Source: NRAs (2018).

Note: In Germany, one scheme is in place (the network reserve), which was temporarily approved by the EC and another scheme is planned (the capacity reserve), which was approved by the EC in February 2018. Changes with respect to 2016 are outlined in red.

247 Figure 43 shows the costs incurred to finance CMs in countries where CMs are currently operational[179]. Although these costs differ significantly across Europe, they currently represent a perceptible share of the wholesale energy prices, e.g. in Ireland where they amounted to 33% of the average DA wholesale energy prices in 2017, and to a lesser extent in Greece (6%), France (5%) and Spain (3%). Moreover, such costs are expected to rise in the coming years as the CMs approved or envisaged become operational, e.g. in Great Britain where they are expected to account for approximately 4% of DA wholesale energy prices in 2018. These costs may impact the scope for suppliers' competition, e.g. they often reduce the contestable share of the end-consumers' electricity bill.

179 Provided that the relevant data was made available to the Agency.

Figure 43: Costs incurred or envisaged to finance CMs, per unit demand and expressed as a percentage of DA prices in Europe, 2017–2018 (euros per MWh demand and %)



Source: NRAs and ACER calculations (2018).

Note: No information was available for Greece, Germany and Italy referring to the envisaged costs in 2018. For France, the overall costs are approximations assuming that all capacity is valued at the market price.

6.2 Contribution of interconnectors to adequacy

248 As highlighted in previous MMRs, the starting point in the process of determining whether to implement a CM should be an assessment of the resource adequacy situation. Given the increasing interdependence of national electricity systems, a robust adequacy assessment needs to properly consider the contribution of interconnectors to adequacy, as such a contribution may be a determining factor when deciding to implement a CM.

249 In this context, regional (i.e. wider than national) or pan-European adequacy assessments, such as ENTSO-E's Mid-term Adequacy Forecast (MAF)[180], are vital for ensuring that the contribution of interconnectors to adequacy is realistically assessed. Such a contribution may deliver the desired levels of security of supply at a lower cost for end consumers.

250 By contrast, last year's MMR concluded that most national adequacy assessments ignore, or at best tend to underestimate, the actual contribution of interconnectors to security of supply. More specifically, the report showed that, as of 2016, in ten countries, the contribution of interconnectors was not considered, or was assessed to be non-existent in the 'central' scenario, often used to take a decision on whether to implement a CM[181]. The situation in 2017 did not significantly improve, i.e. national adequacy assessments continued to ignore the contribution of interconnectors to security of supply in at least nine countries[182]. Out of these nine countries, three have implemented or have decided to implement a CM. For countries that have implemented or consider to implement a CM, this purely national approach is all the more surprising in the context of a move towards a more integrated IEM. This may lead to (or contribute to) a situation of overcapacity at the expense of end consumers.

251 As mentioned above, an EU-wide approach to tackle adequacy issues would probably be more cost-efficient. It would also limit as much as possible any potential distortion created by uncoordinated CMs. As an example, relying on pan-European assessments (e.g. on ENTSO-E's MAF) when taking decisions on adequacy (such as whether to implement a CM) are likely to bring substantial benefits. These benefits could be estimated by accessing detailed data underlying the MAF calculations and comparing them with the outcomes of national adequacy assessments; however, the necessary MAF data are not currently available to the Agency.

180 See the latest ENTSO-E's 'Mid-term adequacy forecasts' (MAFs), available at: https://www.entsoe.eu/outlooks/midterm/.

181 See Table 4 of the Electricity Wholesale Markets Volume of the MMR 2016.

182 This includes three countries (Bulgaria, Spain and Sweden) which have already implemented a CM, and six others (Austria, the Czech Republic, Estonia, Norway, Romania and Slovakia) where the national generation capacity is considered to provide 'adequate' security of supply levels. Additionally, in last year's MMR, Germany was listed among the countries that did not consider the contribution of interconnectors in the adequacy assessments used to take decisions on CMs. For this year's MMR it was not possible to confirm whether this continued to be the case in 2017.

252 More generally, based on European studies[183], assessing and ensuring adequacy at pan-European level would bring yearly benefits of approximately 3 billion euros, compared to separately ensuring adequacy at national levels. These savings would be obtained by mutualising peak power plants, thus limiting the generation capacity required to ensure adequacy.

253 In sum, relying on robust and realistic regional or pan-European adequacy assessments will definitely contribute to achieving the desired levels of security of supply at a lower cost for end consumer.

183 See https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf p.89. The benefits are in the range of 1.5 to 3 billion euros in 2015, and of 3 to 7.5 billion euros by 2030.

Annex 1: Additional figures and tables

Table 5: Average DA price differentials across European borders (ranked) – 2012–2017 (euros/MWh)

	Average price differentials (euros/MWh)							Average of absolute price differentials (euros/MWh)						
Border	2012	2013	2014	2015	2016	2017	2012-2017	2012	2013	2014	2015	2016	2017	2012-2017
AT-IT	-31.5	-23.8	-17.6	-21.1	-13.7	-20.2	-21.3	31.5	24.1	17.7	21.1	13.7	**20.2**	21.4
AT-HU	-8.9	-4.6	-7.7	-9.0	-6.4	-16.2	-8.8	11.7	8.9	9.2	10.1	7.4	**16.9**	10.7
AT-SI	-10.4	-5.4	-7.7	-9.8	-6.6	-15.3	-9.2	12.6	8.5	8.7	11.7	7.4	**15.3**	10.7
GB-NL	7.1	7.1	11.0	15.6	16.9	12.4	11.7	9.1	8.8	11.2	15.8	17.0	**13.1**	12.5
CH-DE	6.9	7.0	4.0	8.6	8.9	11.8	7.9	9.1	9.3	5.6	9.8	9.5	**13.0**	9.4
FR-GB	-8.2	-15.8	-17.6	-17.2	-12.4	-6.8	-13.0	13.4	17.4	17.7	17.5	15.4	**12.5**	15.7
PL-SK	-1.4	-0.6	9.3	4.0	5.0	-4.1	2.1	6.9	8.1	11.1	8.1	9.1	**11.1**	9.1
DE-FR	-4.3	-5.5	-1.9	-6.8	-7.8	-10.8	-6.2	5.1	7.8	4.7	7.5	8.0	**10.9**	7.3
NL-NO2	18.8	14.6	14.0	20.3	7.1	10.4	14.2	19.1	15.1	14.1	20.3	7.5	**10.6**	14.4
GB-IE	-11.6	-10.0	-8.1	1.5	4.0	5.9	-3.1	16.9	18.6	17.7	15.2	13.8	**10.5**	15.4
ES-FR	0.3	1.0	7.5	11.8	2.9	7.3	5.1	11.4	17.6	16.7	14.7	8.0	**10.2**	13.1
CH-IT	-24.5	-16.9	-13.6	-12.5	-4.8	-8.8	-13.5	24.9	17.3	13.7	13.3	6.2	**10.2**	14.3
FR-IT	-27.1	-18.3	-15.7	-14.2	-5.9	-9.4	-15.1	29.0	19.4	16.0	14.4	7.3	**9.8**	16.0
HU-SK	8.7	5.1	6.9	7.0	4.0	9.4	6.8	10.2	5.2	6.9	7.0	4.0	**9.4**	7.1
GR-IT	-11.8	-15.4	11.2	2.5	2.5	5.5	-0.9	21.0	20.8	14.6	9.7	8.2	**9.0**	13.9
DE-PL	1.1	1.1	-10.2	-5.9	-7.5	-2.8	-4.0	7.4	8.2	11.7	8.6	10.0	**8.7**	9.1
CZ-PL	0.9	0.1	-10.0	-5.2	-5.3	-0.5	-3.3	6.5	7.8	11.2	7.9	9.1	**8.4**	8.5
DE-SE4	8.4	-2.1	0.8	8.8	-0.5	1.9	2.9	11.7	7.7	6.5	11.1	4.9	**7.9**	8.3
FI-NO4	5.5	2.6	4.6	9.3	7.4	7.5	6.1	5.6	2.9	5.0	9.8	7.6	**7.6**	6.4
IT-SI	21.0	18.4	9.9	11.3	7.0	4.9	12.1	21.1	18.5	10.0	11.4	7.2	**7.0**	12.5
BE-NL	-1.0	-4.5	-0.4	4.6	4.4	5.3	1.4	2.7	6.1	2.2	5.9	6.1	**7.0**	5.0
DE-DK1	6.3	-1.2	2.1	8.8	2.3	4.0	3.7	7.5	6.8	4.8	9.7	3.9	**6.6**	6.5
DE-NL	-5.4	-14.2	-8.4	-8.4	-3.3	-5.1	-7.5	5.5	14.2	8.4	8.7	3.8	**6.6**	7.9
DE-DK2	5.0	-1.8	0.6	7.2	-0.4	2.1	2.1	7.1	5.8	5.0	9.2	4.3	**6.2**	6.3
PL-SE4	7.3	-3.3	11.1	14.6	6.9	4.6	6.9	10.6	5.2	11.9	15.3	9.2	**5.5**	9.6
NO4-SE1	-0.6	-0.6	0.0	-0.7	-3.9	-5.1	-1.8	0.7	1.0	0.8	1.3	4.1	**5.4**	2.2
NO4-SE2	-0.6	-0.6	0.0	-0.7	-3.9	-5.1	-1.8	0.7	1.0	0.8	1.4	4.1	**5.4**	2.2
DK1-NO2	7.2	1.6	3.4	3.1	1.5	1.3	3.0	8.8	6.4	6.1	4.5	3.1	**4.8**	5.6
CZ-SK	-0.5	-0.5	-0.7	-1.2	-0.3	-4.5	-1.3	0.5	0.5	0.7	1.3	0.6	**4.5**	1.3
CH-FR	2.6	1.5	2.2	1.7	1.1	1.0	1.7	7.1	5.3	4.6	5.1	4.9	**4.5**	5.3
CZ-DE	-0.2	-1.0	0.2	0.7	2.2	2.3	0.7	4.0	4.3	2.8	3.2	3.9	**4.5**	3.8
LT-PL	3.1	12.3	7.1	4.4	0.1	-1.7	4.2	8.5	13.6	13.5	10.9	6.1	**4.2**	9.4
BE-FR	0.0	4.2	6.2	6.2	-0.1	-0.4	2.7	2.8	4.6	6.2	6.3	2.6	**3.8**	4.4
HU-RO	2.5	7.0	5.8	4.2	2.1	2.4	4.0	13.9	12.5	10.1	4.4	2.5	**3.0**	7.7
LT-SE4	10.4	9.0	18.2	19.0	7.0	2.9	11.1	14.0	11.2	18.2	19.2	7.1	**3.0**	12.1
DK1-SE3	4.0	-0.5	-0.9	0.9	-2.6	-1.2	0.0	6.3	4.2	3.0	3.1	2.7	**2.9**	3.7
NO1-SE3	-2.8	-1.9	-4.3	-2.2	-3.1	-2.2	-2.7	2.9	3.2	4.4	2.2	3.3	**2.9**	3.1
FI-SE1	4.9	2.0	4.6	8.5	3.5	2.3	4.3	4.9	2.0	4.6	8.5	3.5	**2.3**	4.3
FI-SE3	4.3	1.7	4.4	7.7	3.2	1.9	3.9	4.4	1.8	4.4	7.7	3.2	**1.9**	3.9
NO3-SE2	-0.3	-0.2	0.1	0.1	-0.3	-1.3	-0.3	0.4	0.8	0.6	0.6	0.9	**1.7**	0.9
DK2-SE4	3.4	-0.3	0.2	1.6	-0.1	-0.2	0.8	4.6	1.8	1.5	2.1	0.7	**1.7**	2.1
EE-LV		-8.0	-12.5	-10.8	-3.0	-1.5	-7.2		8.0	12.5	10.8	3.1	**1.5**	7.2
LT-LV		0.0	0.0	-0.1	-0.4	0.4	0.0		0.0	0.0	0.1	0.5	**0.5**	0.2
ES-PT	-0.8	0.6	0.3	-0.1	0.2	-0.2	0.0	0.8	1.1	0.5	0.1	0.3	**0.4**	0.5
EE-FI	2.6	2.0	1.6	1.4	0.6	0.0	1.4	4.8	3.0	1.6	1.4	0.7	**0.1**	1.9

Source: ENTSO-E and ACER calculations (2018).

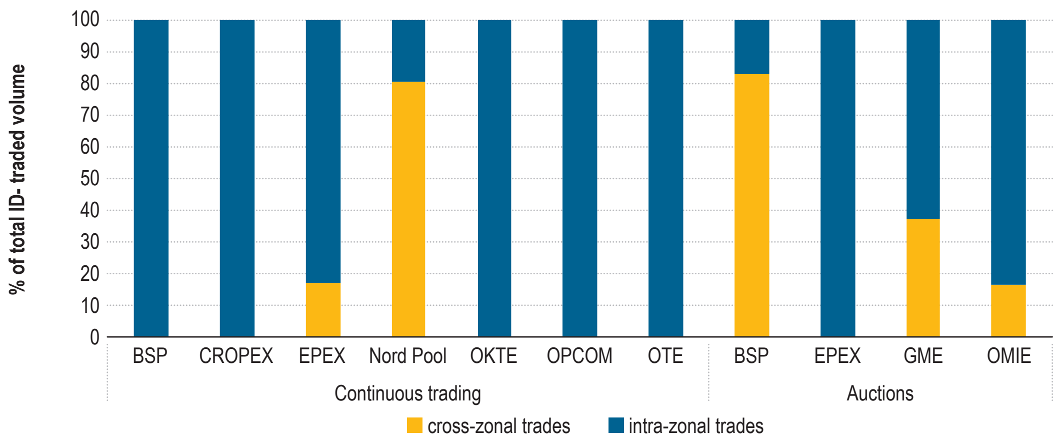
Note: Since 2017, information on DA prices is sourced exclusively from the ENTSO-E TP. For Ireland, this implied a change in the price reference used for the 2017 analysis, compared to previous years. Irish prices until 2016 refer to half-hourly ex-post initial system marginal price (EP2 SMP), plus capacity payments (euros/MWh) applied to imports/exports to/from Ireland, as provided by the Irish market operator (SEMO). Irish prices for 2017 refer to the ex-ante system marginal price (EA2 SMP) published on the ENTSO-E TP.

Table 6: ID-traded volumes per product, per bidding zone, per NEMO – 2017 (TWh)

Volume (TWh)		Continuous trading					Auctions	
NEMO	Bidding zone	Half-hourly	Hourly	Predefined block order	Quarter-hourly	User-defined block order	Hourly	Quarter-hourly
BSP	SI		0.04		0.00	0.10	0.28	
CROPEX	HR		0.05					
EPEX Spot	AT		2.15		0.25			
	BE		1.08					
	FR	0.05	4.10					
	DE/LU	0.04	34.62		4.60			5.22
	GB	6.08	9.11					
	NL		1.48					
	NO2		0.11					
	CH	0.00	2.00		0.08			
GME	IT						22.49	
Nord Pool	DK1		1.01					
	DK2		0.59					
	EE		0.15					
	FI		0.98					
	DE/LU	0.00	1.26		0.01			
	GB	0.00	0.00	0.00				
	LV		0.09					
	LT		0.19					
	NL		0.11					
	NO1		0.05					
	NO2		0.14					
	NO3		0.06					
	NO4		0.03					
	NO5		0.08					
	SE1		0.39					
	SE2		0.58					
	SE3		0.99					
	SE4		0.14					
OKTE	SK		0.08	0.00		0.06		
OMIE	PT						4.00	
	ES						31.13	
OPCOM	RO		0.15					
OTE	CZ		0.52			0.03		

Source: NEMOs and ACER calculations (2018).

Figure 44: Share of total ID-traded volume per trading method, per nature of trade (intra-zonal vs. cross-zonal), per NEMO – 2017 (% of total ID-traded volume per NEMO)



Source: NEMOs and ACER calculations (2018).

Note: The NEMOs are listed in alphabetical order per type of trading method.

Table 7: Overview of the national GOTs and GCTs per MS – 2017

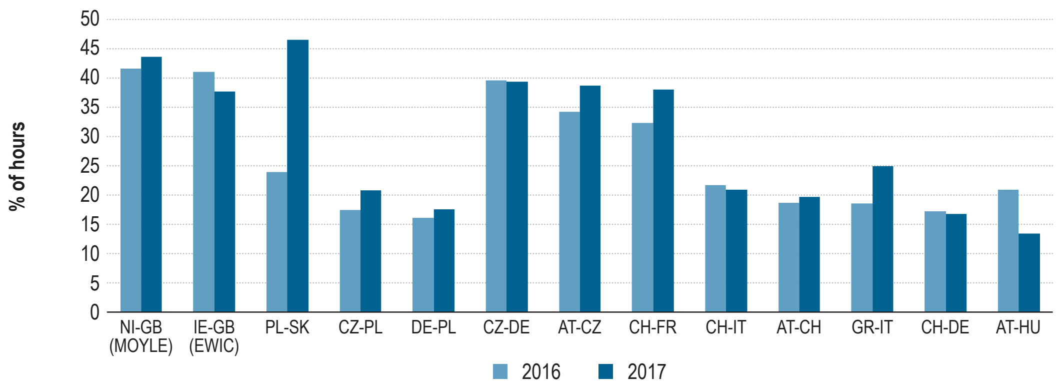
MS	Auction		Continous trading	
	GOT	GCT	GOT	GCT
Austria	-	-	15:00 D-1 CET (60-minute product) 16:00 D-1 CET (15-minute product)	30 minutes before delivery (60-minute product) 5 minutes before delivery (15-minute product)
Belgium	-	-	15:00 D-1 CET	5 minutes before delivery
Croatia	-	-	15:45 D-1 CET	30 minutes before delivery
Czech Republic	-	-	15:00 D-1 CET	60 minutes before delivery
Denmark	-	-	14:00 D-1 CET	60 minutes before delivery
Estonia	-	-	14:00 D-1 CET	30 minutes before delivery
Finland	-	-	14:00 D-1 CET	30 minutes before delivery
France	-	-	15:00 D-1 CET (60-minute product) 15:30 D-1 CET (30-minute product)	30 minutes before delivery (60-minute product) 5 minutes before delivery (30-minute product)
Germany	45 days before delivery	15:00 D-1 CET	08:00 D-1 CET (all products - Nord Pool) 15:00 D-1 CET (60-minute product - Epex Spot) 15:30 D-1 CET (30-minute product - Epex Spot) 16:00 D-1 CET (15-minute product - Epex Spot)	20 minutes before delivery (between TSO areas - Nord Pool) 0 minutes before delivery (internal TSO areas - Nord Pool) 30 minutes before delivery with 5 minutes before delivery in local TSO areas (Epex Spot)
Great Britain	-	-	00:00 D-1 CET (all products - Nord Pool) 15:30 D-1 CET (30-minute product - Epex Spot) 48 hours before delivery (pre-defined block orders - Epex Spot)	16 minutes before delivery (60-minute product and user-defined block order - Nord Pool) 15 minutes before delivery (30-minute product - Nord Pool) 17 minutes before delivery (predefined block order - Nord Pool) 15 minutes before delivery (30-minute product - Epex Spot) 16, 17 or 19 minutes (depending on the predefined block order - Epex Spot)
Hungary	-	-	15:45 D-1 CET	120 minutes before delivery
Italy (1)	MI1: 12:55 D-1 CET MI2: 12:55 D-1 CET MI3: 17:30 D-1 CET MI4: 17:30 D-1 CET MI5: 17:30 D-1 CET MI6: 17:30 D-1 CET MI7: 17:30 D-1 CET	MI1: 15:00 D-1 CET MI2: 16:30 D-1 CET MI3: 23:45 D-1 CET MI4: 3:45 D CET MI5: 7:45 D CET MI6: 11:15 D CET MI7: 15:45 D CET	-	-
Latvia	-	-	14:00 D-1 CET	30 minutes before delivery
Lithuania	-	-	14:00 D-1 CET	60 minutes before delivery
Luxembourg	45 days before delivery	15:00 D-1 CET	15:00 D-1 CET (60-minute product) 15:30 D-1 CET (30-minute product) 16:00 D-1 CET (15-minute product)	30 minutes before delivery with 5 minutes before delivery in local TSO areas
Netherlands	-	-	14:00 D-1 CET (Nord Pool) 15:00 D-1 CET (Epex Spot)	5 minutes before delivery (Epex Spot + Nord Pool)
Norway	-	-	14:00 D-1 CET	60 minutes before delivery
Poland	-	-	8:00 D CET	15:30 D CET
Portugal (2)	A1: 17:00 D-1 CET A2: 21:00 D-1 CET A3: 1:00 D CET A4: 4:00 D CET A5: 8:00 D CET A6: 12:00 D CET A1: 17:00 D CET	A1: 19:00 D-1 CET A2: 22:00 D-1 A3: 2:00 D CET A4: 5:00 D CET A5: 9:00 D CET A6: 13:00 D CET A1: 19:00 D CET	-	-
Romania	-	-	18:00 D-1 CET	120 minutes before delivery
Slovakia	-	-	15:00 D-1 CET	60 minutes before delivery
Slovenia (3)	MI2: 12:55 D-1 CET MI6: 17:30 D-1 CET	MI2: 16:30 D-1 CET MI6: 11:15 D CET	15:00 D-1 CET	60 minutes before delivery

MS	Auction		Continous trading	
	GOT	GCT	GOT	GCT
Spain	A1: 17:00 D-1 CET A2: 21:00 D-1 CET A3: 1:00 D CET A4: 4:00 D CET A5: 8:00 D CET A6: 12:00 D CET A1: 17:00 D CET	A1: 19:00 D-1 CET A2: 22:00 D-1 A3: 2:00 D CET A4: 5:00 D CET A5: 9:00 D CET A6: 13:00 D CET A1: 19:00 D CET	-	-
Sweden	-	-	14:00 D-1 CET	60 minutes before delivery
Switzerland	-	-	15:00 D-1 CET (60-minute product) 15:30 D-1 CET (30-minute product) 16:00 D-1 CET (15-minute product)	60 minutes before delivery (60-minute product) 30 minutes before delivery (15 and 30-minute product)

Source: NEMOs and ACER calculations (2018).

Note: Bulgaria, Greece and Ireland are not included in this table, because products pursuant to the CACM Regulation were not tradable yet in these markets as of 31 December 2017. (1) 'MI' refers to the number of the seven distinct auction rounds in Italy (MI = 'Mercato infragiornaliero'). (2) 'A' refers to the number of the six auction rounds, while the last auction round corresponds to the first one, but with limited trading possibilities for the remaining hours of the delivery day (see also the note under Figure 30 for information about the Iberian auctions). (3) 'MI2 and MI6' correspond to the second and sixth auction round in Italy to which market participants in Slovenia can participate implicitly.

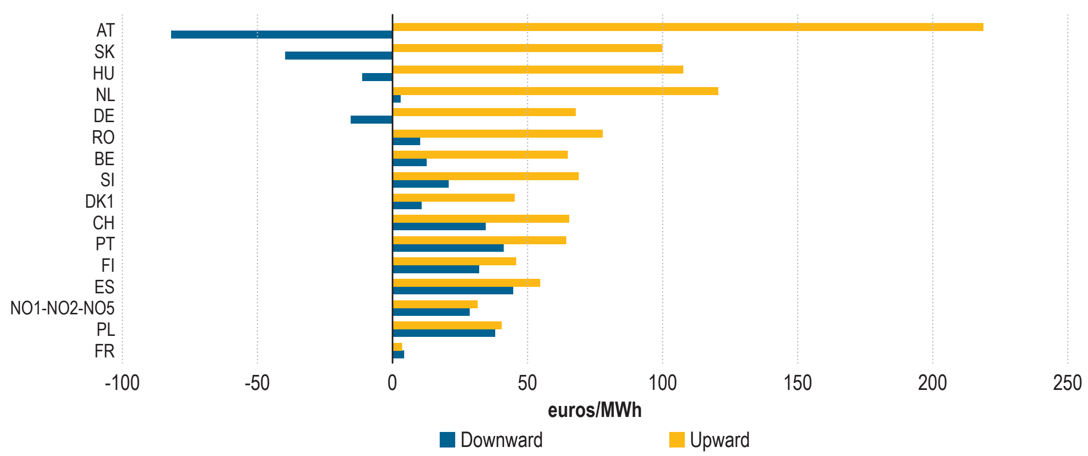
Figure 45: Percentage of hours with net DA nominations against price differentials per border (ranked) – 2016–2017 (%)



Source: ENTSO-E, NRAs, Vulcanus and ACER calculations (2018).

Note: Only borders with 'wrong-way flows' during more than 2% of the hours of 2017 are shown in this figure. Borders coupled before 2017 are not shown in this figure.

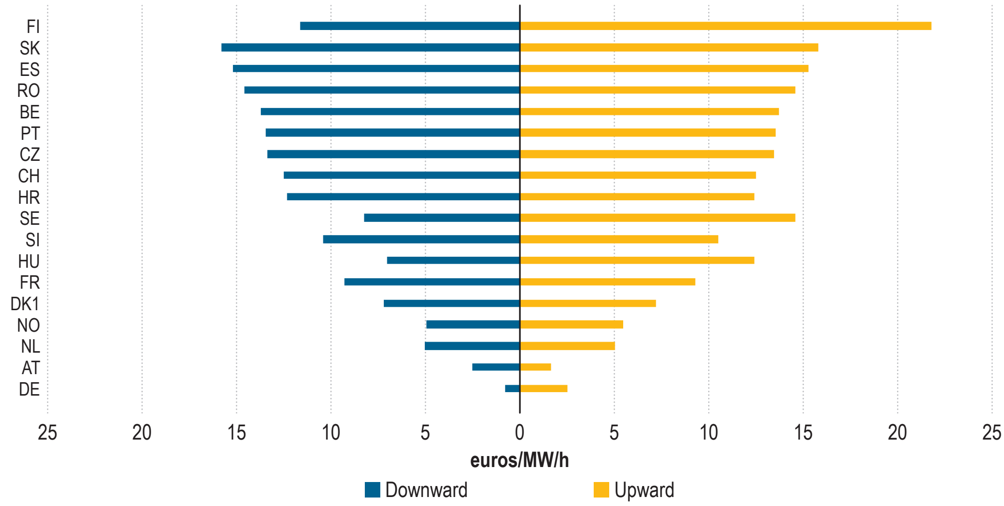
Figure 46: Weighted average prices of balancing energy activated from aFRRs (upward and downward activation) in a selection of EU markets – 2017 (euros/MWh)



Source: ENTSO-E and ACER calculations (2018).

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 47: Average prices of balancing capacity (upward and downward capacity from aFRRs) in a selection of EU markets – 2017 (euros/MW/h)



Source: NRAs and ACER calculations (2018).

Table 8: Average oriented NTCs on European borders – 2016–2017 (MW and %)

CCR	Directional border	NTC 2017 (MW)	NTC 2016 (MW)	Change 2017/2016
Baltic	EE → FI	1,006	965	4.2%
	EE → LV	795	779	2.1%
	FI → EE	1,008	97	3.4%
	LT → LV	587	554	5.9%
	LT → PL	377	311	21.4%
	LT → SE4	450	476	-5.5%
	LV → EE	649	670	-3.1%
	LV → LT	1,044	1,021	2.2%
	PL → LT	268	149	80.6%
	SE4 → LT	579	490	18.3%
Channel	FR → GB	1,736	1,715	1.3%
	GB → FR	1,736	1,713	1.4%
	GB → NL	997	1,003	-0.6%
	NL → GB	997	1,002	-0.6%
Core (excl. CWE)	CZ → DE-AT-LU	3,226	3,151	2.4%
	CZ → PL	599	606	-1.1%
	CZ → SK	1,824	1,865	-2.2%
	DE-AT-LU → CZ	1,777	806	120.0%
	HR → SI	1,464	1,445	1.4%
	HU → HR	1,200	1,164	3.1%
	HU → RO	677	654	3.6%
	HU → SK	792	811	-2.4%
	PL → CZ	837	710	17.8%
	PL → SK	540	542	-0.4%
	RO → HU	581	615	-5.6%
	SI → HR	1,467	1,491	-1.6%
	SK → CZ	1,200	1,192	0.7%
	SK → HU	1,117	1,049	6.5%
	SK → PL	491	493	-0.5%
Hansa	DE-AT-LU → DK1	1,384	1,312	5.6%
	DE-AT-LU → DK2	513	537	-4.4%
	DK1 → DE-AT-LU	525	194	171.0%
	DK2 → DE-AT-LU	501	522	-4.1%
	PL → SE4	180	99	82.6%
	SE4 → PL	466	367	27.0%

CCR	Directional border	NTC 2017 (MW)	NTC 2016 (MW)	Change 2017/2016
Italy North	DE-AT-LU → IT-North	244	236	3.8%
	FR → IT-North	2,528	2,333	8.4%
	IT-North → DE-AT-LU	100	116	-13.9%
	IT-North → FR	1,019	1,054	-3.4%
	IT-North → SI	649	667	-2.8%
	SI → IT-North	548	521	5.2%
Italy North (Virtual)	DE-AT-LU → IT-North-AT	241	243	-0.6%
	IT-North-AT → DE-AT-LU	98	100	-2.5%
IU	GB → IE(SEM)	974	654	48.9%
	IE(SEM) → GB	759	551	37.7%
Nordic	DK1 → SE3	529	641	-17.5%
	DK2 → SE4	1,210	1,525	-20.6%
	FI → SE1	1,056	1,058	-0.1%
	FI → SE3	1,183	1,183	0.0%
	SE1 → FI	1,514	1,424	6.3%
	SE3 → DK1	634	564	12.5%
	SE3 → FI	1,183	1,184	-0.1%
	SE4 → DK2	1,177	1,209	-2.6%
Norwegian borders	DK1 → NO2	1,223	1,475	-17.0%
	NL → NO2	691	693	-0.2%
	NO1 → SE3	1,247	1,446	-13.7%
	NO2 → DK1	1,223	1,397	-12.5%
	NO2 → NL	648	662	-2.1%
	NO3 → SE2	548	587	-6.7%
	NO4 → SE1	442	396	11.6%
	NO4 → SE2	101	87	16.7%
	SE1 → NO4	301	306	-1.4%
	SE2 → NO3	730	735	-0.8%
	SE2 → NO4	140	133	5.2%
	SE3 → NO1	1,308	1,809	-27.7%
SEE	BG → GR	408	496	-17.6%
	GR → BG	364	374	-2.9%
	RO → BG	263	267	-1.5%
SWE	ES → FR	2,294	1,941	18.2%
	ES → PT	1,979	1,932	2.4%
	FR → ES	2,559	2,426	5.5%
	PT → ES	2,978	2,382	25.0%
Swiss borders	CH → DE-AT-LU	5,027	5,151	-2.4%
	CH → FR	1,180	1,125	4.9%
	CH → IT-North	2,840	2,992	-5.1%
	DE-AT-LU → CH	2,258	2,271	-0.6%
	FR → CH	3,006	2,974	1.1%
	IT-North → CH	1,705	1,717	-0.7%

Source: ENTSO-E, Nord Pool and ACER calculations (2018).

Annex 2: Unscheduled flows

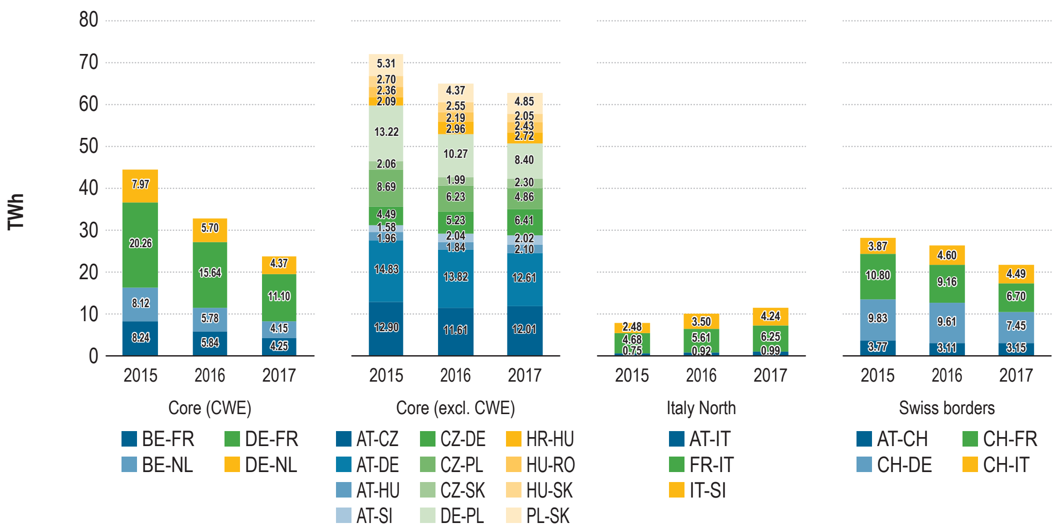
254 As shown in previous editions of the MMR[184], UFs present a challenge to the further integration of the IEM. Their persistence reduces tradable cross-zonal capacity, market efficiency and network security.

255 The definitions of the flows used in this Annex and the detailed process description are provided in the methodological paper on UFs[185]. Briefly, UFs are comprised of UAFs, most of which stem from insufficient coordination in capacity calculation and allocation processes, and LFs, which originate from electricity exchanges inside other bidding zones.

256 The data on the allocated flows[186] (AFs) used in the analysis of this Annex were provided to the Agency 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.

257 The Agency has been monitoring the evolution of UFs in Europe (on the borders in the Core, Italy North and Swiss borders regions[187]) since 2012. They increased from 2012 to 2015, and then decreased. In 2017, they amounted to 120 TWh, down 11% year-on-year (and 22% below their 2015 peak).

Figure 48: Absolute aggregate sum of UFs for four CCRs – 2015–2017 (TWh)



Source: Vulcanus and ACER calculations (2018).

Note: The calculation methodology used to derive UFs is described in the methodological paper on UFs[188]. 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.

Compared to previous MMR editions, UFs are shown for the full CZ-DE border, instead of being split between CZ-DE 50Hz and CZ-DE TenneT.

184 See Section 5.1 “Unscheduled flows” (p. 28), of the Electricity Wholesale Markets Volume of MMR 2015.

185 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.

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

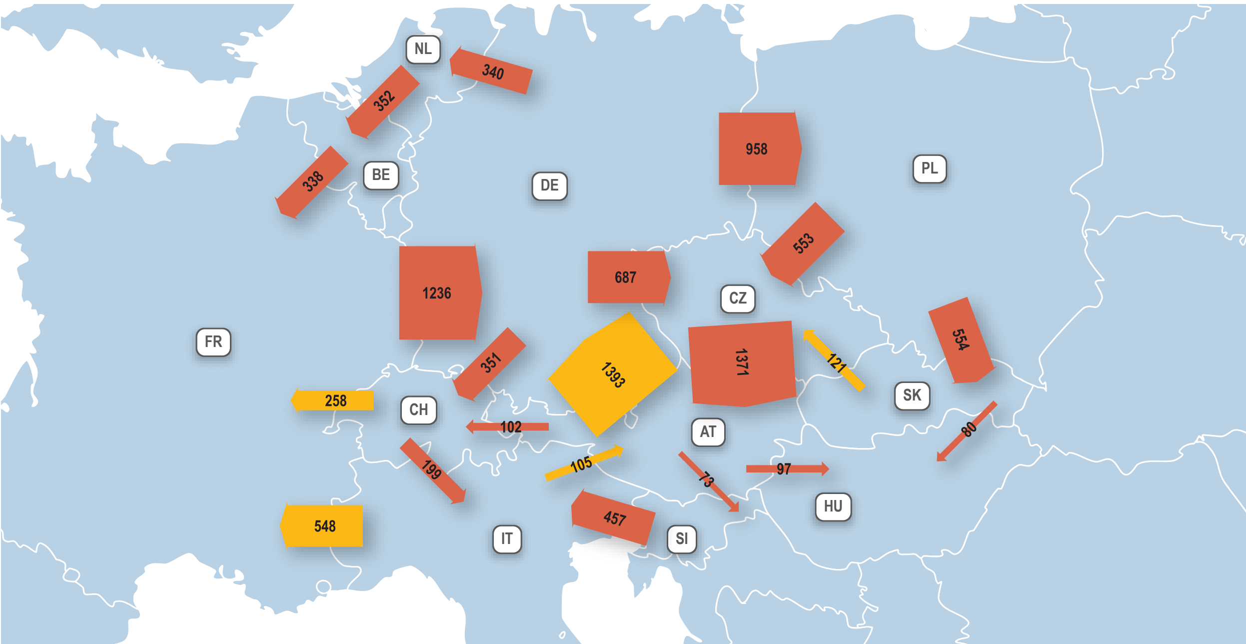
187 UFs are smaller in the SEE (4.6 TWh) and SWE (0.4 TWh) regions.

188 See footnote 185

258 In the Core (CWE) region, UF decreased 28% year-on-year, mostly driven by a decrease on the French-German border, and are 46% below their 2015 level. In the Swiss borders region, UFs decreased by 18%, and are now 23% below their 2015 level. In the Core (excl. CWE) region, UFs decreased by 4% (following a 10% decrease between 2015 and 2016), but accounted for more than half of all European UFs. In the IT North region, UFs rose by 14%, due to increases on the French-Italian and Italian-Slovenian borders. They now lie 45% above their 2015 level.

259 Figure 49 shows the prevailing direction of UFs volumes. It reveals that the overall pattern still consists of two major loops, from Germany to the Netherlands to the west, and to Poland to the east. UFs decreased on the German-Polish border by almost 20% year-on-year; they are 34% lower than in 2015. Unscheduled flows between Austria and Germany decreased by 9%, year-on-year. Figure 50 and Figure 51 depict the UFs decomposition into UAFs and LFs.

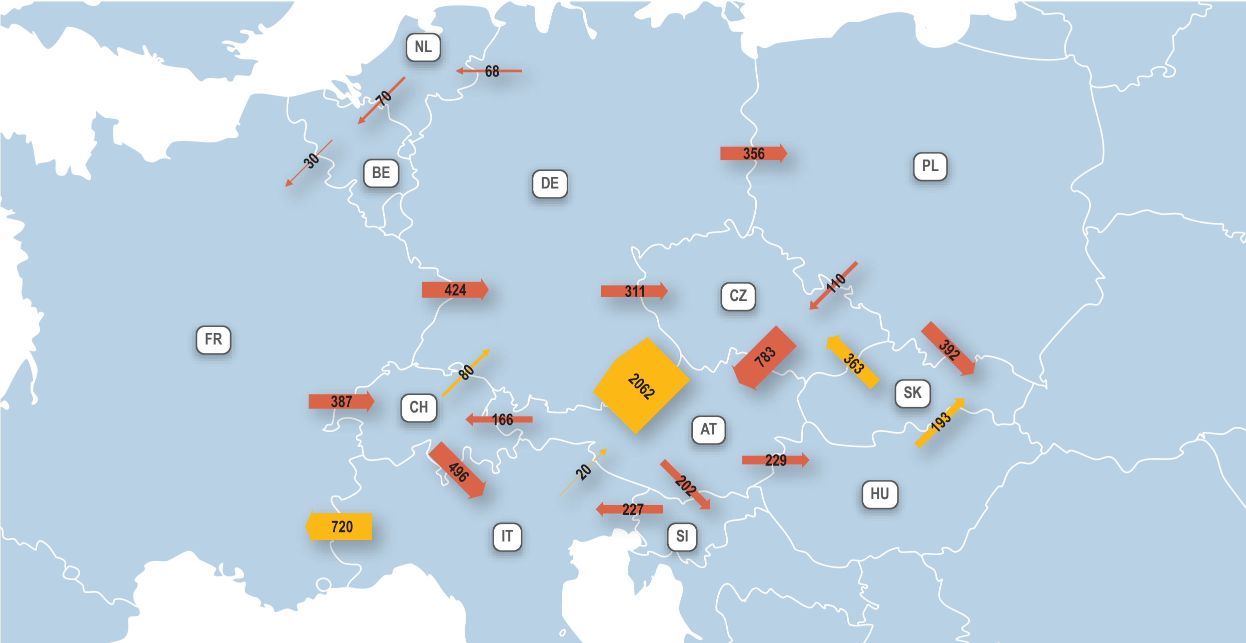
Figure 49: Average oriented UFs in Continental Europe – 2017 (MW)



Source: Vulcanus and ACER calculations (2018).

Note: Average UFs are average hourly oriented values in 2017. 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 of the physical flow if the cross-zonal schedule exceeds the physical flow.

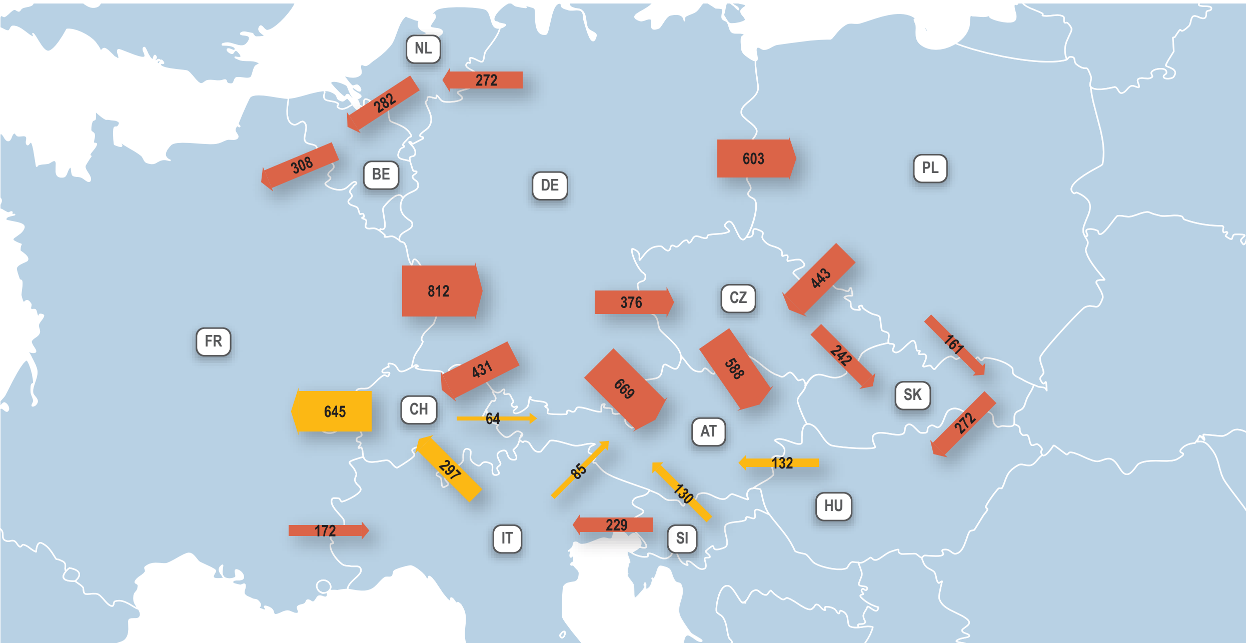
Figure 50: Average oriented UAFs in Continental Europe – 2017 (MW)



Source: Vulcanus and ACER calculations (2018).

Note: Average UAFs are average hourly oriented values in 2017. 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 51: Average oriented LFs in Continental Europe – 2017 (MW)



Source: Vulcanus and ACER calculations (2018).

Note: Average LFs are average hourly oriented values in 2017. 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.

260 Overall, in the Core, Italy North and Swiss borders regions, UAFs amounted to 96 TWh, whereas LFs made up 81 TWh. Core (CWE) was the only region in which UAFs were smaller than LFs (UAFs were 28% smaller than LFs in this region), probably because this region relies on FB market coupling. On the other hand, in the Italy North region, UAFs were 66% larger than LFs, suggesting room for improved coordination in this region.

261 Table 9 below describes average absolute UAFs and LFs in Continental Europe. The largest UAFs and LFs were both observed in the Core (excl. CWE) region. The CWE region is the only one within which UAFs are lower than LFs, indicating that good coordination is in the phase of being achieved in this region.

Table 9: Average absolute UAFs and LFs in Continental Europe – 2017 (MW)

	Average absolute UAFs (MW)	Average absolute LFs (MW)
Core (CWE)	1,443	2,005
Core (excl. CWE)	5,982	4,587
Italy North	1,245	752
SEE	361	284
SWE	17	35
Swiss borders	2,311	1,906

Source: Vulcanus, ENTSO-E and ACER calculations (2018).

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.

262 Despite significant improvements in many regions, 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 seems to reduce UAFs significantly, but does not affect LFs. LFs may be tackled through bidding zone reconfiguration or other measures to ensure non-discrimination in capacity calculation.

Annex 3: Detailed costs of remedial actions

263 Costly remedial actions are mostly used by TSOs to manage congestions related to exchanges within bidding zones. They usually consist of geographically altering the generation dispatch, either directly or by trading energy.

264 Table 10 describes the detailed costs incurred by remedial actions in European countries, subject to data availability. For most countries (but for Estonia, France and Latvia), redispatching made up the largest share of costs. Seven jurisdictions reported zero cost, whereas three countries reported costs over 300 million euros. Germany even reported costs of over a billion euros.

Table 10: Detailed costs incurred by remedial actions in European countries – 2017

Country	Total volume (GWh)	Re-dispatching (thousand euros)	Counter-trading (thousand euros)	Cost of other actions (thousand euros)	Cost of RAs to preserve/ increase XB capacity (thousand euros)	Contribution from other TSOs (thousand euros)	Contribution to other TSOs (thousand euros)	Net exchange of RAs (received, thousand euros)	Total cost (thousand euros)	Total cost 2016 (thousand euros)	Total cost 2015 (thousand euros)	Relative change 2017/2016	Cost of RAs per MWh load (euros/ MWh)
DE	24,313	1,130,654	30,714	0	0	0	0	0	1,161,368	602,651	911,985	93%	2.2
ES	12,182	366,113	5,362	0	5,362	14,803	2,719	12,084	371,475	516,050	690,932	-28%	1.6
AT	1,757	83,571	0	11,474	0	226,835	-2,640	229,475	92,405	31,636	27,712	192%	1.5
GB	10,569	371,265	333	0	8,978	1,813	2,027	-214	373,625	300,332	465,553	24%	1.2
PT		44,525	0	0		63	0	63	44,525	121,982	67,551	-63%	1.0
NL	685	48,712	0	13,635	37,659	0	8	-8	62,355	65,328	5,539	-5%	0.6
LT	77	1,549	0	0		0	0	0	1,549	NA		NAP	0.2
NO	896	11,546	9	949	NA	9	18	-9	12,522	17,084	20,830	-27%	0.1
HU	9	2,612	0	0	0	0	0	0	2,612	0		NAP	0.1
LV	4	0	311	0	0	0	0	0	311	383	709	-19%	0.0
BE	185	2,048	208	0	260	29	232	-203	2,488	3,295	NA	-24%	0.0
FI	35	1,372	384	0	461	6	44	-38	1,756	0	3,784	NAP	0.0
FR	272	6,383	2,200	0	2,200	0	0	0	8,583	618	854	1289%	0.0
EE	4	NA	102	0	102	0	0	0	102	404	1,746	-75%	0.0
CZ	9	547	0	0	0	116	55	61	602	2,009	3,055	-70%	0.0
SI	2	83	0	0	13	0	0	0	83	0	0	NAP	0.0
Total	**51,001**	**2,070,980**	**39,623**	**26,058**	**55,035**	**243,674**	**2,463**	**241,211**	**2,136,361**	**1,661,772**	**2,200,250**	**129%**	

Source: NRAs[189] and ACER calculations (2018).

Note: The Agency requested data for congestion-related remedial actions. 'Redispatching' refers to directly altering the generation dispatch, whereas 'counter-trading' refers to energy trading. 'Contribution from other TSOs' refers to the costs of actions taken by one TSO, but borne by adjacent TSOs. "Cost of other actions" refers to the costs of remedial actions other than redispatching and countertrading, e.g. changing the grid topology. NRAs were also asked to provide the "Costs of all (redispatch/countertrading/others) remedial actions used to preserve/increase cross-zonal capacity". All other costs were assumed to relate to internal exchanges. In general, positive euro values refer to costs incurred by TSOs, and negative values to their revenues, whereas for "contributions from other TSOs", positive values refer to money received from other TSOs and negative values to money paid to other TSOs. As the central dispatching model is applied in Greece, Ireland, Italy, Northern Ireland and Poland, costs specifically linked with remedial actions were not available. No costs related to costly remedial actions were incurred in Bulgaria, Croatia, Denmark, Luxembourg, Romania and Slovakia. Sweden and Switzerland did not provide details on costs or did not have the data available. Data relates to 2017, unless stated otherwise.

189 See footnote 107 for more information on costs of remedial actions in Germany.

Annex 4: Efficiency of current bidding zone configuration (indicators, qualification criteria and detailed analysis)

265 Due to the limited capacity of the EU electricity transmission infrastructure, the efficiency and functioning of wholesale electricity markets and network operational security are impacted by electricity flows from source to sink. Congestion management methods and market designs arrangements are intended to handle these flows in the most efficient way, while ensuring secure operations and providing for an appropriate framework for the optimal use and development of the EU electricity system.

266 The EU Electricity Target Model handles network congestion through bidding zones. Electricity exchanges within a bidding zone are unlimited (and do not directly pay for congestion costs), then a combination of preventive and curative methods allows the management of the underlying infrastructure limitation. Preventive methods mainly define ex-ante limitations to cross-zonal trade by calculating cross-zonal capacities and efficiently allocating them to market players. Curative methods, e.g. redispatching or counter-trading, update the network topology and dispatch pattern when relevant, to avoid jeopardising operational security.

267 An efficient bidding zone configuration should rely on structural congestions (i.e. be designed so that structural congestions lie between bidding zones) in order to ensure cost-effectiveness and relevant price signals. It should also ensure non-discrimination between internal and cross-zonal exchanges. The Agency's market efficiency analysis focuses on two main criteria: cross-zonal capacity and costly remedial actions. An informative analysis is also conducted on LFs. Each of these criteria is assessed through various indicators.

268 First, monitoring cross-border capacity allows checking whether structural congestions are located between bidding zones, and whether exchanges internal to bidding zones affect cross-border capacity. Three main indicators assess this aspect:

1) Historical NTCs are compared with benchmark NTCs[190] on AC borders to assess the impact of LFs and internal elements on cross-border capacity. For a given country, yearly average bidirectional NTCs are summed over borders, and compared with the sum of benchmark capacities on these borders[191].

2) On bidding-zone borders, worst-case physical flows due to cross-border exchanges are compared with the thermal capacities of interconnectors in order to approximately infer the margin available for cross-border exchanges. For a given NTC border, the worst-case physical flow due to cross-border exchanges comes from a combination of exchanges on all borders that loads the interconnector the most. It is computed by combining positive exchange PTDFs[192] with yearly average NTCs. Flows are then summed over all interconnectors and compared to the thermal capacities of interconnectors. On FB borders (i.e. in the Core (CWE) area), average margins on interconnectors[193] are compared to maximum flows. Border values[194] are then combined to obtain country-level values: the average (weighted by thermal capacity of interconnectors) makes up the first indicator, whereas the second indicator looks at the worst border (i.e. the border with the lowest ratio).

190 For more information on benchmark capacity calculation, see Sub-section 3.1.2.

191 The sum is made on borders for which both the benchmark capacity and the NTC were available. For FB borders, the cubic root of the (realised or benchmark) directional FB volume was used.

192 If the exchange PTDF for A>B is positive, and the exchange PTDF B>A is negative, only the A>B PTDF will be used. The exchange PTDFs are derived from the representative Continental Europe CGM.

193 To ensure consistency with NTC borders, margins and maximum flows are only retrieved for interconnectors in base case configuration (i.e. without contingency).

194 Core (CWE) borders are considered altogether as one 'border', as within this region, flow margins are jointly available for all borders.

269 Second, LFs monitoring compares, for each border, average absolute LFs[195] with the thermal capacities of interconnectors in order to assess the share of interconnectors consumed by internal exchanges. For a given country, the average over borders (weighted with thermal capacities of interconnectors) is then derived, along with the worst border (i.e. the highest border ratio). These indicators are informative and are not formally taken into account in the efficiency assessment, but rather hint at possible underlying causes for low cross-zonal capacity or high costs of remedial actions.

270 Finally, costly remedial actions are assessed to estimate whether further remedial actions may be available to alleviate discrimination of cross-zonal flows. The cost and volume of remedial actions were divided by national electricity consumption[196] in order to ensure comparability between countries. In the future, non-costly remedial actions may also be tracked, as they may also allow cross-zonal capacity to be increased. In countries were a central dispatching model is applied, it is usually not possible to derive costs directly related to remedial actions (as only the full dispatch cost is computed); thus the costs of remedial actions are not used for the assessment of these jurisdictions.

271 Table 11 shows the detailed country-level assessment of market efficiency, and leads to the following conclusions.

Table 11: Bidding zone efficiency (detailed assessment) – 2015–2017

		Cross-zonal capacity		Loop Flows		Remedial actions	
Country	NTC vs. benchmark (average)	Physical flows due to cross-border exchanges vs. thermal capacity on interconnectors (average)	Physical flows due to cross-border exchanges vs. thermal capacity on interconnectors (worst border)	Loop Flows vs. thermal capacity on interconnectors (average)	Loop Flows vs. thermal capacity on interconnectors (worst border)	Cost of remedial actions per unit demand (average, euro/MWh demand)	Volume of costly remedial actions vs. demand (average, % demand)
AT	51%	54%	39%	21%	56%	0.8	3%
BE	62%	NA	NA	8%	9%	0.0	0%
BG	23%	28%	27%	NA	NA	0.0	0%
CH	64%	33%	23%	5%	7%	NA	NA
CZ	52%	48%	34%	19%	56%	0.0	0%
DE	58%	46%	20%	9%	27%	1.7	5%
DK	48%	20%	20%	NA	NA	0.0	0%
EE	NA	NA	NA	NA	NA	0.1	0%
ES	53%	28%	23%	NA	NA	2.3	5%
FI	NA	NA	NA	NA	NA	0.0	0%
FR	68%	45%	33%	8%	14%	0.0	0%
GB	NA	NA	NA	NA	NA	1.2	0%
GR	65%	30%	30%	NA	NA	NA	NA
HR	60%	56%	49%	NA	NA	0.0	0%
HU	47%	54%	31%	11%	15%	0.1	0%
IE	NA	NA	NA	NA	NA	NA	NA
IT	63%	46%	33%	7%	23%	NA	NA
LT	NA	NA	NA	NA	NA	0.2	7%
LV	NA	NA	NA	NA	NA	0.1	14%
NL	62%	83%	83%	8%	8%	0.6	14%
NO	NA	NA	NA	NA	NA	0.1	0%
PL	21%	34%	26%	19%	27%	NA	NA
PT	42%	23%	23%	NA	NA	1.7	0%
RO	26%	29%	27%	NA	NA	0.0	0%
SE	NA	NA	NA	NA	NA	NA	NA
SI	61%	69%	65%	13%	15%	0.0	93%
SK	54%	57%	26%	10%	15%	0.0	0%

Source: Data provided by NRAs through the EW template (2018), ENTSO-E and ACER calculations.

195 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.

196 Defined in line with footnote 108.

Note: 'NA' describes a missing value. The average cost of remedial actions over 2015–2017 was divided by the average 2015–2016 electricity consumption[197]. For Great Britain, consumption in the United Kingdom was used as a proxy. Benchmark capacity and LFs were available only for Continental Europe. As a result, Danish data for cross-zonal capacity only relates to the DE-DK1 border[198]. Moreover, due to the central dispatch nature of the Greek, Irish, Italian and Polish systems, their remedial actions information may encompass more than just congestion management, and may not be fully comparable with values from other countries. Benchmark NTCs, absolute LFs and thermal capacities were assessed for 2016.

272 As far as cross-zonal capacity is concerned, very few countries performed adequately, when comparing, for example, yearly average NTCs with benchmark capacities. Poland, Bulgaria and Romania performed the worst, approximately 75% below the benchmark capacity. Flows due to cross-zonal exchanges seldom used more than 50% of the thermal capacities of interconnectors. For the Denmark West-Germany border, cross-zonal exchanges used only 20% of thermal capacity, and 23% on the Portuguese-Spanish border. LFs consumed a sizable share of interconnector capacity, taking up to 56% of thermal capacity on the Austrian-Czech border, and 27% between Germany and Poland. Only seven countries exhibited average loop flow levels below 10% of thermal capacity. Costs of remedial actions varied significantly between countries: Spain[199], Germany, Portugal and Great Britain[200] all had average remedial actions costs of at least 1 euro/MWh, whereas the Netherlands and Austria had an approximate cost of 0.7 euros/MWh. On the other hand, RAs amounted to less than 0.1 euros/MWh for 12 countries.

273 The comparison of LFs with thermal capacities hints at the reasons why NTCs are below benchmark capacities. For example, for Poland, low NTCs seem to come from large LFs originating in neighbouring countrie[201] . For other countries, low available cross-zonal capacity may be related to congestions within the country, which can be inferred from the relatively high costs of remedial actions (e.g. for Spain). In other cases, such as Bulgaria or Romania, further analysis is needed to understand the origin of the low RAM on interconnectors.

274 The performance assessment focuses on the available cross-zonal capacity and costly remedial actions criteria, displayed in columns 2 and 7 of Table 11, respectively. The available capacity indicator focuses on the comparison between NTC and benchmark capacities; the costly remedial actions criteria assesses the normalised cost of remedial actions. Other indicators included in this table are for informative purposes, and are intended as an aid to understand the main factors leading to inadequate performance. The detailed qualification process for each criteria is described below.

275 The available cross-zonal capacity criterion was qualified based on the following thresholds:

- If the average cross-zonal capacity over AC borders of a bidding zone amounts to at least 100% of the benchmark capacity, the performance is adequate.
- If the average cross-zonal capacity over AC borders of a bidding zone amounts to at least 75% of the benchmark capacity, and reasonable price convergence[202] is achieved, the performance is adequate.
- If the average cross-zonal capacity over AC borders of a bidding zone amounts to at least 75% of the benchmark capacity, and reasonable price convergence is not achieved, the performance is to be closely monitored.

197 See footnote 108.

198 On this border, a bilateral agreement between Germany and Denmark aims at reaching a capacity of 1100MW in 2020. However, this capacity increase is subject to a cost cap of 40 million euros per year (on actions required to ensure this cross-zonal capacity), making the actual extent of the increase less certain. See https://en.efkm.dk/news/news-archive/2017/jun/denmark-and-germany-agree-on-increasing-electricity-trade-between-their-countries/.

199 Some recent network investments are expected to mitigate the network constraints within Spain, see e.g. http://www.mincotur.gob.es/energia/planificacion/Planificacionelectricidadygas/desarrollo2015-2020/Documents/Planificaci%C3%B3n%202015_2020%20%202016_11_28%20VPublicaci%C3%B3n.pdf p. 538.

200 Some recent network investments, e.g. the Western HVDC link (see http://www.westernhvdclink.co.uk/), are expected to mitigate the related network constraints within Great Britain in the future.

201 PST work was recently conducted on the German Polish border, in order to enhance power flow regulation. See http://www.50hertz.com/Portals/3/Content/NewsXSP/50hertz_flux/Dokumente/20160413_Press%20Release_PSE_50Hertz_Temporary-disconnection-interconnector-Krajnik-Vierraden_FINAL.pdf.

202 Reasonable price convergence is achieved if the average absolute price spread for 2015–2017 over all borders is below 5 euros/MWh.

- If the average cross-zonal capacity over AC borders of a bidding zone is below 75% of the benchmark capacity, and reasonable price convergence is achieved, the performance is to be closely monitored.

- If the average cross-zonal capacity over AC borders of a bidding zone is below 75% of the benchmark capacity, and reasonable price convergence is not achieved, the performance is poor.

276 For borders where detailed data were lacking, the following qualifications were applied:

- In the Nordic area, the experimental CGM data provided did not allow the computation of meaningful benchmark cross-zonal capacities. However, based on publicly available Nordic data and a simplified assessment[203], a 65-70% RAM level may be estimated for Nordic CNEs. As benchmark capacities assume 85% RAM levels, the available cross-zonal capacity in the Nordic region would probably reach approximately 80% of the benchmark.

- The following HVDC links performed poorly, but did not affect qualified assessments: LT-PL, LT-SE4, PL-SE4[204].

277 The following methodology was used to set costly remedial action thresholds. Threshold values should allow a neat classification of countries into three main categories. As a result, threshold values should be sufficiently different to differentiate between the best performing and worst performing countries. Moreover, poorly performing countries should correspond to countries in which congestion cost issues have been raised. As a result, the following threshold values were set:

- Poor performance is assumed when the average cost per unit demand is above 1.0 euro/MWh;

- Performance should be closely monitored when the average remedial action cost per unit demand is between 0.2 and 1.0 euro/MWh; and

- Performance is assumed to be adequate when the cost of remedial actions per unit demand lies below 0.2 euros/MWh.

203 See paragraph 118.

204 See Annex 1 (p. 62) of the Electricity Wholesale Markets Volume of the MMR 2016.

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