Agency for the Cooperation of Energy Regulators

Council of European Energy Regulators

ACER/CEER

Annual Report on the Results of Monitoring the Internal Electricity Markets in 2015

September 2016

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Contents

1 Introduction

1 This Electricity Wholesale volume is one of four volumes that make up the Market Monitoring Report (MMR). The other volumes are Gas Wholesale, Electricity and Gas Retail, and Customer Protection and Empowerment. For this year, the Gas and Electricity Wholesale Chapters will be published earlier than the two other volumes. This will allow the reader to have access to these documents when they are ready, i.e. earlier than for the previous MMR.

2 The performance of the electricity internal market depends on the efficient use of the European electricity network and the good performance of wholesale electricity markets in all timeframes. When electricity wholesale markets are integrated via sufficient interconnector capacity, then competition will work to the benefit of all consumers and improve energy system adequacy and supply security in the long run.

3 The Capacity Allocation and Congestion Management (CACM)[1] Regulation that is currently being implemented provides for clear objectives to deliver an integrated Internal electricity market in the following areas: (i) full coordination and optimisation of capacity calculations performed by Transmission System Operators (TSO) within regions and based on appropriate bidding zones; (ii) the use of flow-based capacity calculation methods in highly meshed networks; and (iii) regular monitoring and reviewing of the efficiency of bidding zone configuration. 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, subject to the capacity of the existing network. Implementing these provisions remains a key priority for the Agency for the Cooperation of Energy Regulators ("the Agency" or "ACER").

4 This document is structured as follows. The next Chapter presents key developments that have affected electricity wholesale markets in recent years in the European Union (EU). Chapter 3 focuses the level of cross-zonal capacities made available for trade, while the performance of the capacity calculation process is assessed in Chapter 4. The distortive effect of unscheduled flows (UFs) is illustrated in Chapter 5. The respective performance of forward, day-ahead (DA), intraday (ID) and balancing markets is presented in, respectively, Chapters 6, 7, 8 and 9. The document ends with a presentation of the situation of capacity mechanisms (CMs) (Chapter 10). To make this volume more readable, each Chapter starts with a summary explaining the aim, structure and main insights.

1 Commission Regulation (EU) 2015/1222, see OJ L 197, 25/7/2015.

2 Key developments over the last decade

Chapter summary

This Chapter reports on prices in European wholesale electricity markets in 2015. It also includes an analysis of the evolution of electricity wholesale prices, of the electricity generation mix and of other key trends observed during the last decade.

The downward trend of electricity wholesale prices continued in several European markets in 2015, due to, among other factors, increasing electricity production from renewable energy sources (RES), whereas in other markets (e.g. Belgium and Spain) prices increased in 2015, after some years of decline. The analysis of the evolution of wholesale prices in a selection of European electricity markets over the last decade shows that the increasing frequency of low-price periods (when prices are often zero or negative) is not accompanied by the occurrence of very high-price periods (reflecting situations of generation scarcity), that are crucial for "compensating" for the decreased load factors of conventional generation plants. The analysis suggests that the implementation of CMs hinders the occurrence of scarcity situations, hence reducing the frequency of high-price periods (e.g. in Spain); however, when markets are allowed to rebalance supply and demand (through some combination of retirement of surplus capacity and growth in demand), high-price periods re-emerge (e.g. in Belgium in 2015).

The Chapter suggests a situation of generation overcapacity in the assessed markets where high-price periods have decreased significantly or disappeared. This result does not characterise all national European markets. However, today, the capacity margin for Europe as a whole exceed two to three times the most commonly used generation adequacy standards. This indicates an overall situation of overcapacity in Europe in spite of the recently observed decline in conventional generation capacity.

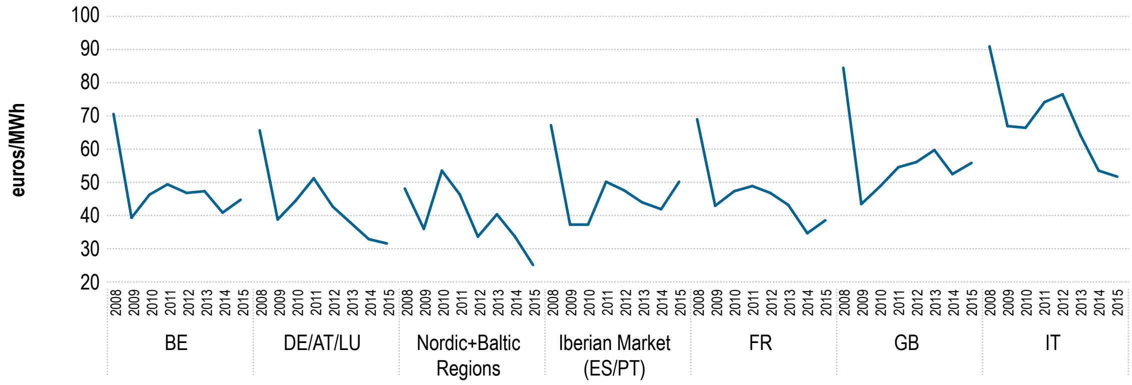
Low wholesale prices and the declining occurrence of high-price periods (e.g. in the Netherlands they decreased from 275 in 2005 to 0 observations in 2015) have affected the financial stability of conventional generation in recent years. The Chapter shows that the combination of relatively cheap coal and low carbon prices has most significantly affected the competitiveness of gas-fired generation plants, which have recently been struggling to remain viable and some have been closed.

Another relevant development in recent years is the emergence or increase in the costs associated with CMs, redispatching actions and other system services, such as the procurement of balancing capacity. These costs emerge from less market-based mechanisms than electricity wholesale prices and tend to increase the non-contestable share of the electricity bill for final consumers, which reduces the scope for competition in electricity retail markets. Eliminating or reducing the various forms of remuneration based on generation capacity (i.e. per MW) and optimising redispatching costs (e.g. through a better bidding zone configuration) would internalise the underlying costs of the supply of electricity in the wholesale energy price and hence enlarge the contestable share of the electricity bill.

5 In 2015, wholesale electricity prices in several markets, including Germany, the Nordic and Baltic regions and Italy, prolonged the downward trend that has been observed since 2011 (Figure 1). The drop in prices in the Nordic and Baltic regions has been more pronounced than elsewhere due to higher-than-average water reservoirs levels in the Nordic Region, mainly in Norway and Sweden. Some other markets recorded a perceptible increase in wholesale prices, e.g. in Spain due to relatively low hydropower generation or in Belgium due to 24% of its nuclear capacity being offline for most of the year[2]. A slightly less relevant increase in wholesale prices was observed in France and Great Britain.

2 Doele 1 and Tihange 2, accounting for 1,441 MW of the installed nuclear capacity of 5,904 MW, were offline for most of 2015.

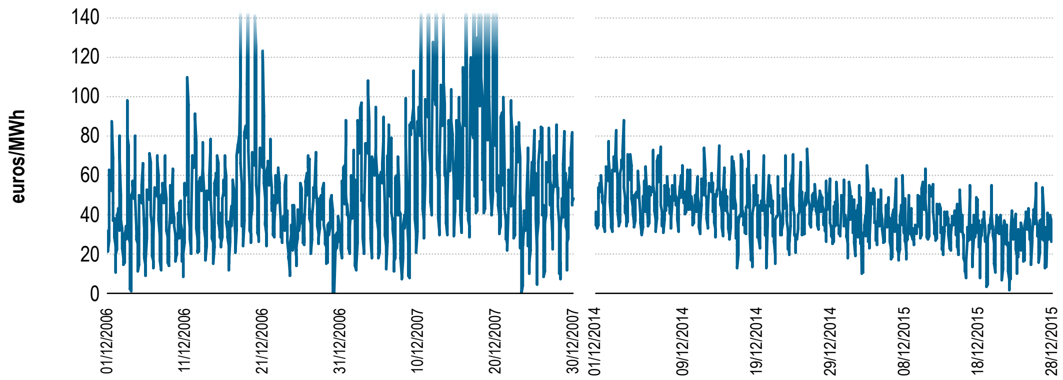
Figure 1: Evolution of DA wholesale electricity prices in different European power exchanges – 2008–2015 (euros/MWh)



Source: Energy Market Observatory System (EMOS), Platts and power exchanges (2016).

6 About a decade ago (and even more recently[3]), most wholesale price forecasts envisaged a significant increasing trend in price volatility[4]. It was expected that, due to the penetration of intermittent generation from RES, an increasing frequency of low-price periods would reduce the load factors of conventional generation plants and hence their revenues[5]. These revenues would be compensated by an increased frequency of high-price periods (price spikes) that would emerge at times of scarcity[6]. However, Figure 2 shows that, for example, these expectations with respect to price volatility for the Netherlands did not materialise, as volatility was significantly lower in 2014 and 2015 than ten years before. A similar pattern is observed in most of the European wholesale markets (see more examples in Figure 37, Figure 38, and Figure 39 in the Annex).

Figure 2: Hourly DA prices in the Netherlands – December 2006, 2007, 2014 and 2015 (euros/MWh)



Source: EMOS and Platts (2016).

7 The decline in price volatility and in the frequency of high-price periods cannot only be explained by a decrease in the average wholesale prices. Indeed, in Spain there were no price spikes (as defined in footnote 12) in 2015, even though prices increased, reaching approximately the same levels as in 2005 and 2006, when some occurrences of price spikes were recorded (see Figure 5). The factors that explain the frequency of low and high-price periods are presented below.

3 For example, see the summary report “How wind variability could change the shape of British and Irish electricity markets” at http://www.poyry.com/sites/default/files/impactofintermittencygbandi-july2009-energy.pdf.

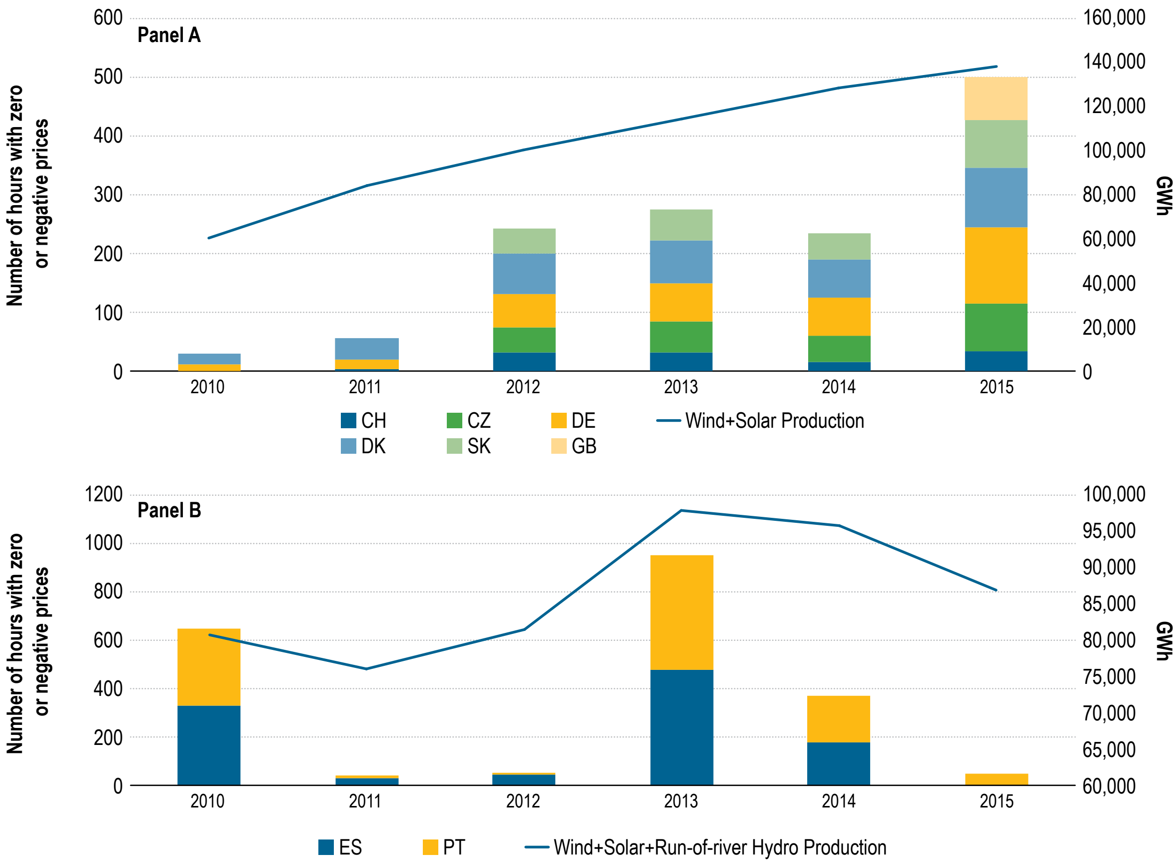
4 Price volatility describes how quickly or widely prices can change.

5 These low-priced periods usually occur when the production from intermittent generation plants is relatively high compared to demand.

6 Scarcity can be defined as a situation where the actual “reserve margins” are close to zero. In this context, “reserve margins” refer to any generating capacity that is available to cover the load at a given point in time. Although scarcity only arises in real time, scarcity situations are likely to be anticipated by market participants in the form of high-price periods in the different market timeframes.

8 On the one hand, the frequency of low-price periods (i.e. prices reaching zero or negative values) correlates with the steady increase in electricity production from RES, as illustrated in Figure 3 for the 2010–2015 period. This figure includes intermittent generation from wind and solar electricity plants for the Czech Republic, Denmark, Germany, Great Britain, Italy, Slovakia and Switzerland, or the combined production from wind, solar and run-of-river hydro plants in the case of Spain and Portugal.

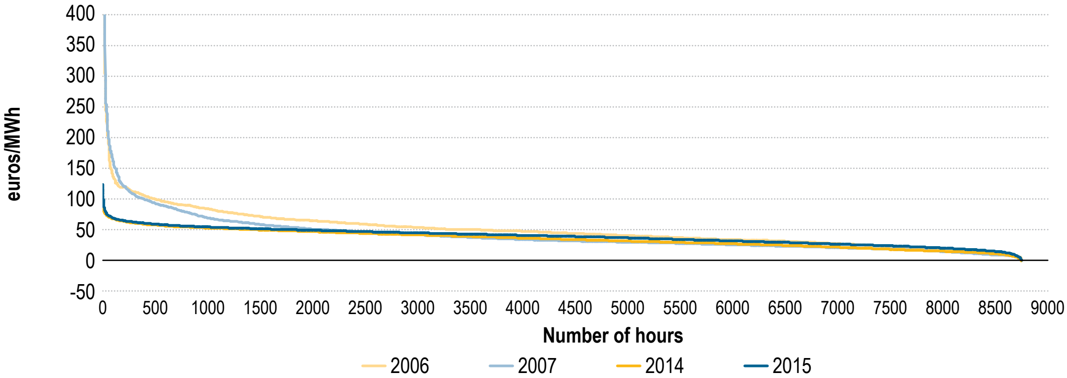
Figure 3: Frequency of zero or negative wholesale prices in a selection of European countries and the quantity of electricity produced from intermittent generation (wind and solar, in combination with run-of-river in the case of the Iberian market) – 2010–2015 (number of hours and GWh)



Source: EMOS, Platts, power exchanges, European Network of Transmission System Operators for Electricity (ENTSO-E) and ACER calculations (2016).

9 On the other hand, the frequency and magnitude of high-price periods have decreased significantly during the last decade. While this is shown in Figure 3, this effect is even more visible when the price levels and their frequency are expressed in hours and displayed together in price duration curves (see Figure 4 for France and Figure 40, Figure 41 and Figure 42 for the Netherlands, Germany and Spain, respectively, in the Annex).

Figure 4: Wholesale DA price duration curve for France – 2006, 2007, 2014 and 2015 (euros/MWh)



Source: EMOS (2016).

10 Several factors, including the successful integration through market coupling of most European DA markets, have contributed to declining prices and reduced volatility. However, the persistent decline in prices and volatility seems to be explained by an increasing overcapacity[7] in European markets (see Figure 5). While reliability standards (for generation adequacy) and the methodologies to calculate capacity margins (see Section 10.2) are currently not harmonised across Member States (MSs), there is evidence of an excess of installed capacity in Europe.

11 For example, ENTSO-E's 2015 adequacy forecast shows a 2016 "de-rated reserve margin", i.e. margin of reliable available installed capacity over peak load, of 13%[8] for Europe as a whole. This figure can be considered as two to three times what is necessary to maintain the most often used standard of supply reliability[9].

12 The evolution of the gap between installed conventional generation and electricity demand provides an indication of the trend of capacity margins[10]. Figure 5 illustrates this increasing gap[11] and its negative correlation with the occurrence of price spikes[12] for France, Germany, the Netherlands and Spain. Since 2010, markets have virtually ceased to show signs of scarcity which confirms that there is an excess of installed capacity in these four MSs. However, in MSs with relatively limited adequacy margins (e.g. in Belgium), a number of price spikes continued to be observed at times of scarcity. Figure 43 in the Annex shows the evolution of the frequency of price spikes in Belgium, which increased in 2015, most likely as a consequence of the decreasing capacity margins. This confirms that markets do provide signs of scarcity in the form of price spikes when shortages emerge.

7 Overcapacity can be defined as a situation where the difference between the observed reliability margins and the reliability standards defined for a given system is above a certain threshold during a certain period of time. This threshold is not defined in this Chapter, although if margins are two to three times more than what is necessary to maintain the most frequently used standards of reliability, referenced in paragraph (11), they can be assumed to indicate a situation of overcapacity.

8 Based on the (scenario B) values of load forecast and reliable available capacity, provided in figure 3.1.1 and 3.6.1, respectively, in the "ENTSO-E: 2015 Scenario Outlook & Adequacy Forecast", available at https://www.entsoe.eu/Documents/SDC%20documents/SOAF/150630_SOAF_2015_publication_wcover.pdf.

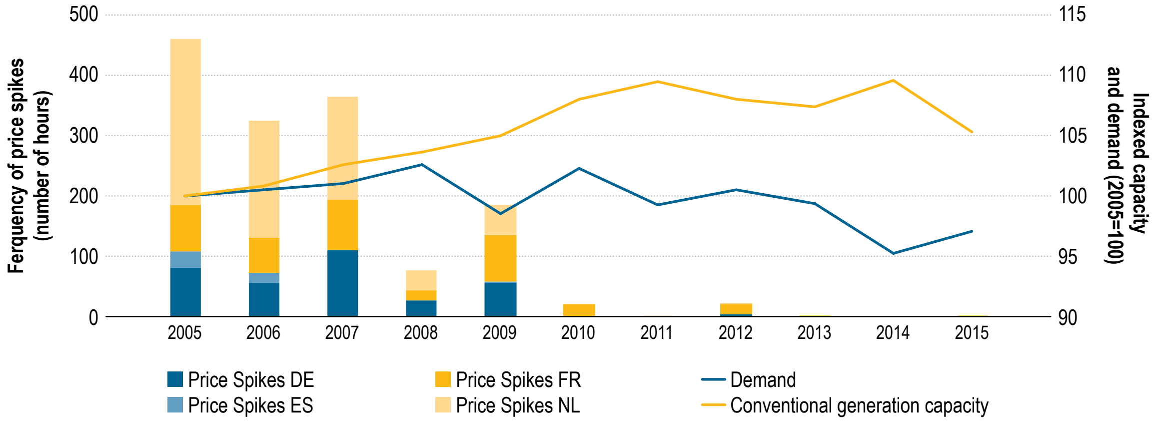
9 The metric most frequently used to assess generation adequacy in Europe is loss of load expectation (LOLE), (see Section 10.2). The most frequently reported reliability standard is a LOLE of 3 hours/year, which can be considered equivalent to a de-rated capacity margin of at most 3-4%, e.g. based on estimates of the National Grid in its "Winter Outlook Report 2015/206" for Great Britain (see the report at http://media.nationalgrid.com/media/1293/ng-winter-review-2016.pdf), which considers a 1.1 hours/year, equivalent to a de-rated capacity margin of 5.1%.

10 An increasing gap suggests that reliability margins are also increasing, because some additional reliability is supposed to be provided by the installed generation from RES, even though its contribution to reliability is proportionally lower than the reliability of conventional generation and a stochastic analysis is required to evaluate the magnitude of such contribution. The total demand recorded per year can be used only as an indication of the trends of reliability margins because, for an accurate adequacy assessment, peak demand should be considered.

11 It should be noted that this gap seems to have narrowed in 2015 and that the 2016 ENTSO-E Summer Outlook describes a *"decline in traditional net generation capacity, already identified in the Winter Outlook 2015/16, and not compensated by the growth in net variable generation capacity"*.

12 A price spike occurrence is considered as an hourly DA price which is three times above the theoretical variable cost of generating electricity with gas-fired generation plants, based on the Title Transfer Facility (TTF) gas DA prices in the Netherlands. This is equivalent to other international assessments of price spikes (see the "ERCOT 2014 State of the Market Report" at https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf), where the threshold is set to 18 times the value of gas measured in British thermal unit (MMBtu), i.e. approximately two to three times the variable cost of generating electricity with gas-fired generation plants.

Figure 5 Evolution of the frequency of price spikes (number of hours per year, left axis), the aggregated installed conventional generation capacity and aggregated electricity demand (indexed to 2005 = 100, right axis) in France, Germany, the Netherlands and Spain – 2005–2015



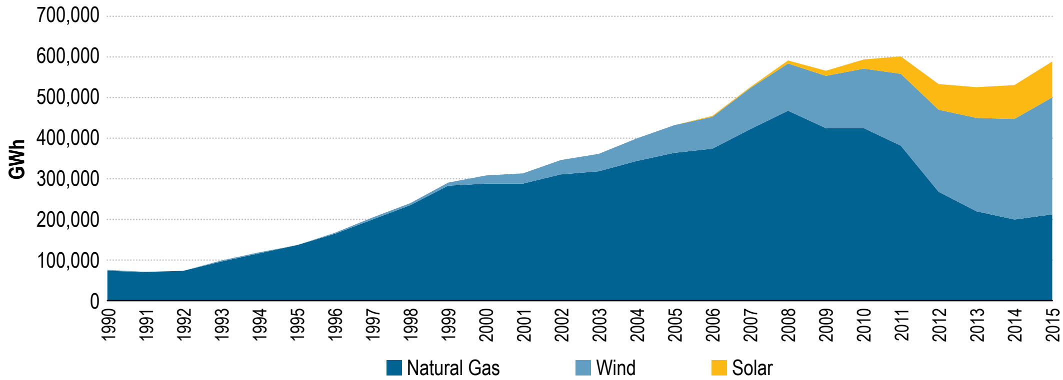
Source: Eurostat, ENTSO-E (2016).

Note: The figures on conventional generation capacity are based on the Eurostat categories of “Electrical capacity, main activity producers – Combustible Fuels, Hydro and Nuclear”. For 2014, the figures on conventional generation capacity are based on 2014 Eurostat figures and the relative change in 2015 compared to 2014 recorded by ENTSO-E in its equivalent categories. The figures on demand are based on ENTSO-E data.

13 Furthermore, Figure 5 shows that the frequency of price spikes in Spain (on average four price spikes per year in the last decade) was significantly lower than in the Netherlands, France and Germany which had an average of, respectively, 61, 32 and 30 spikes per year in the same period. One relevant difference between these markets is that, in Spain, different CMs were introduced since 1997, including ”interruptibility” and other targeted schemes (see further details in Section 10.1), while in the other three markets no CMs were in operation during the analysed period. This suggests that MSs’ interventions, in particular with regard to the introduction of CMs, reduce the actual scarcity, hence the occurrence of high-price periods.

14 Low wholesale prices and the declining occurrence of scarcity price signals have affected the financial viability of conventional electricity generation in recent years. In addition, the combination of relatively cheap coal and low carbon prices has affected, most significantly, the competitiveness of gas-fired generation plants, which have been struggling recently to remain economically viable and have been closed in certain cases. Figure 6 shows the decreasing electricity production from gas-fired generation plants, which was below its 2000 level in 2015.

Figure 6: Annual gross aggregated electricity production from gas-fired, solar and wind electricity plants in the EU – 1990–2014 (GWh)

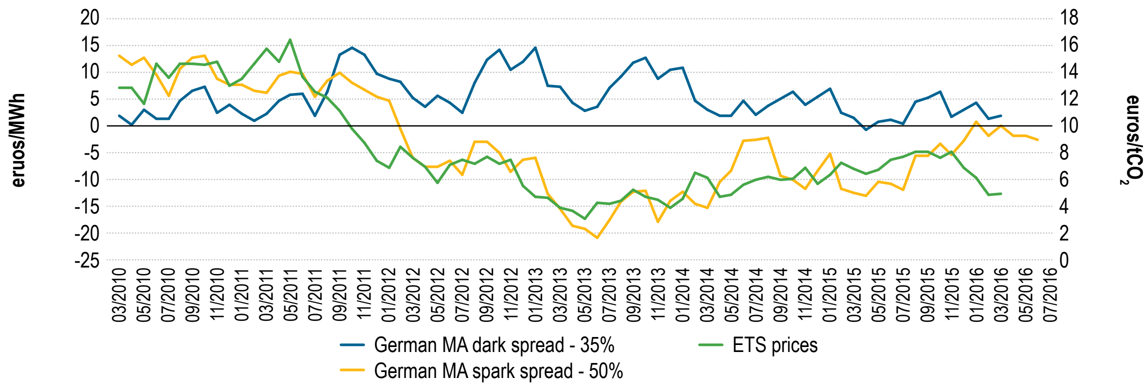


Source: Eurostat, ENTSO-E (2016).

Note: The figures on wind and solar generation are based on the Eurostat categories "Gross electricity generation-Wind" and "Gross electricity generation-Solar", respectively. The figures on generation from gas are based on the Eurostat category "Gross electricity generation-Main activity electricity only-gas". For 2015, the figures are based on 2014 Eurostat figures and the relative change in 2015 compared to 2014 recorded by ENTSO-E in its equivalent categories.

15 The relative impact of declining electricity wholesale prices on gas and coal electricity plants can be measured by using, respectively, the clean spark and clean dark spreads. They represent the theoretical gross margin of one MWh produced with each of these technologies. The relative values of these indicators of profitability are largely driven by the respective values of coal and gas prices in international markets, but also by the level of carbon prices, i.e. the amount that thermal generation plants pay for their CO_2 emissions into the atmosphere. Since coal is on average 2.5 times as polluting as natural gas for the same MWh of electricity[13], coal plants are comparatively less competitive than gas plants when carbon prices are higher, all other things being equal. Figure 7 shows that the significant decline of carbon prices in the EU Emissions Trading System (ETS) in particular until 2013 weakened the competitive position of gas-fired generation plants. However, due to decreasing gas prices, the Combined Cycle Gas Turbine (CCGT) profitability recovered towards the end of 2015.

Figure 7: Evolution of month-ahead (MA) clean spark spreads, MA clean dark spreads and ETS prices (right axis) in Germany – 2010–2015 (euros/MWh and euros/tCO_2)



Source: EMOS and Platts (2016).

13 See for example https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/542570/Fuelmixdisclosurewebpage2016__3_.pdf, page 2.

16 The low ETS prices reduce the ability of this mechanism to support market-driven investments in new low-carbon technologies[14]. Moreover, the ETS does not contribute to decarbonising the electricity sector by encouraging the most polluting electricity generation plants to leave the market. In a context of overcapacity, an adequate exit strategy (i.e. a strategy to manage the retirement of technologies which do not contribute to reduce emissions or to deliver sufficient flexibility, including the removal of possible exit barriers) based on reliable market price signals is as important as steering investments into new, flexible and clean technologies based on the same market price signals.

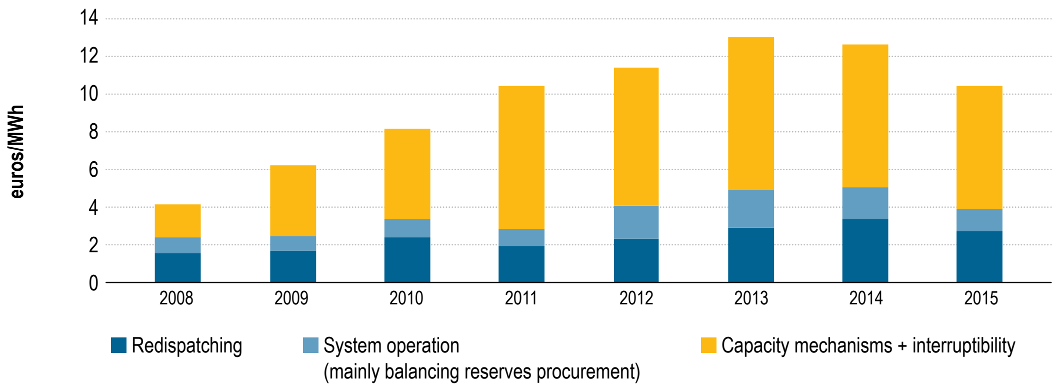
17 In the context of dampened wholesale market prices, stakeholders (generators) have often presented[15] the case of "missing money" vis-à-vis their national governments and asked their MSs to intervene in the electricity market design by introducing a CM[16]. However, in the Agency's view[17], if CMs are considered necessary, they should be used exclusively to address the issue of security of supply based on a robust and coordinated regional resource adequacy

18 Currently, addressing the "missing money" seems to be the priority of MSs, motivated by questionable and overstated generation adequacy arguments. However, in light of the evidence presented above, generation adequacy is not the key challenge MSs are currently facing. In the Agency's view, security of supply would be improved through renewed efforts and stronger commitment from MSs further to enhance the performance and design of wholesale electricity markets by, for example, including adequate price signals to steer investments (when there is generation scarcity) or to exit the market (when there is capacity surplus). Regardless of whether a CM may be needed, a range of no regret measures can be taken in support of improving generation adequacy.

19 Another relevant development in recent years is the emergence or increase of the costs associated with CMs, redispatching actions and other system services, such as the procurement of balancing capacity. These costs typically emerge from less market-based mechanisms than electricity wholesale prices and tend to increase the non-contestable share of the electricity bill for final consumers.

20 Several challenges are associated with the formation of these costs. First, the level of transparency in the level of these costs, and how this is reflected in the end-consumers' bill is usually low. An example of an adequate standard of transparency is the Spanish market, where information related to these costs is publicly available on the website of the National Regulatory Authority (NRA), allowing the trend of these costs to be clearly presented, as shown in Figure 8.

Figure 8: Unit costs associated with capacity payments, redispatching actions and system operation in Spain – 2008–2015 (euros per MWh of demand)



Source: CNMC (2016).

14 See for example https://www.iea.org/publications/freepublications/publication/REPOWERINGMARKETS.pdf, Chapter 2.

15 For example, see the Eurelectric's report "RES Integration and Market Design: are Capacity Remuneration Mechanisms needed to ensure generation adequacy?" available at http://www.eurelectric.org/media/26300/res_integration_lr-2011-030-0464-01-e.pdf.

16 See Section 10.1 for more details on the currently applied CMs in Europe.

17 See http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2005-2013.pdf and http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/CRMs%20and%20the%20IEM%20Report%20130730.pdf.

21 Second, Figure 8 for Spain and Figure 44 for Italy in the Annex show a steady increase in the magnitude of these costs in the period between 2008 and 2013. They decreased in Spain in 2014 and 2015, while in Italy they increased in 2014 and decreased in 2015. In the entire analysed period, these costs increased by more than 200% in Spain and by around 50% in Italy.

22 These costs are to some extent driven by the increasing penetration of RES-based generation. For instance, the need for redispatching actions and balancing reserves is likely to increase with the growing penetration of intermittent electricity generation, and the charges to finance these costs are additional to the charges that finance national RES support schemes. Although these two examples do not allow conclusions to be drawn for the whole of the EU, this trend is already visible[18] or is highly likely to materialise in other countries given the increase in intermittent generation and the emergence of CMs in Europe.

23 Lastly, these costs emerge from less market-based mechanisms than electricity wholesale prices[19] and tend to reduce the share of the end-users' electricity bill that is subject to competition. Eliminating or reducing the various forms of remuneration based on generation capacity (i.e. per MW) and optimising redispatching costs (e.g. through better bidding zone configuration) would internalise the underlying costs of electricity supply in the wholesale energy price and hence enlarge the contestable share of the electricity bill. It is essential that the trend in these costs is monitored closely, in order to ensure that the underlying reasons for any increase in these costs is duly justified.

3 Amount of cross-zonal capacities made available to the market

Chapter summary

The availability of cross-zonal capacities is an essential component of a truly Internal Energy Market. Maximising tradable cross-zonal capacity contributes to a more efficient dispatch of generation units and to a closer integration of national electricity markets.

However, the analysis shows that, in recent years, despite investments in the transmission networks and some improvements in capacity calculation methods, the volume of tradable cross-zonal capacities in the EU and Norway has remained relatively limited (Chapter 3.1). Furthermore, the analysis of the relation between the physical capacities of interconnectors and the commercial capacities made available to the market (Chapter 3.2) shows that, on most EU borders, only a small part of the physical capacities is actually offered to the market and that there are important variations between regions.

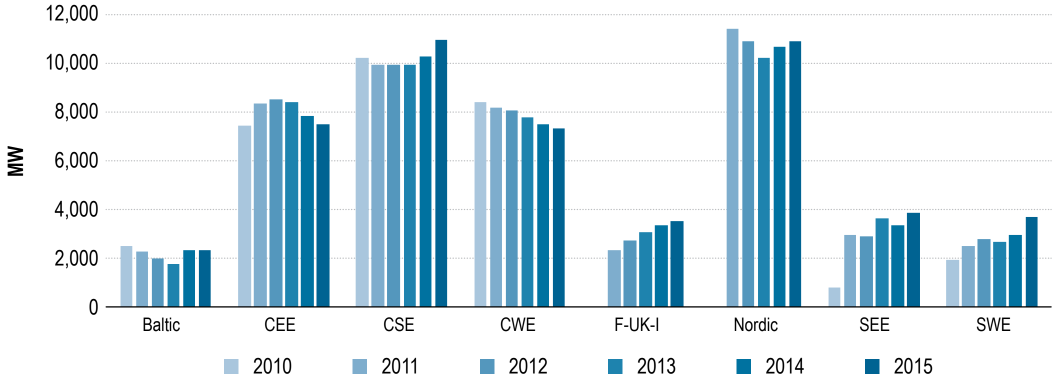
3.1 Evolution of cross-zonal net transfer capacity values

24 Figure 9 presents the average cross-zonal net transfer capacity (NTC) values aggregated per region from 2010 to 2015. It shows that between 2010 and 2015 the overall level of tradable capacities showed moderate improvements or in fact decreased, in particular in Central-East Europe (CEE) and Central-West Europe (CWE).

18 See for example Section 4.2 showing the redispatching costs reported by TSOs in 2015. They increased by more than a factor eight in Germany and by almost a factor two in Great Britain compared to the figures reported by TSOs in 2014.

19 For example, the amount of capacity to be procured in CMs and the methodology to allocate balancing capacity procurement costs to end-consumers are administrative measures that require the regulator's intervention.

Figure 9: NTC averages of both directions on cross-zonal borders, aggregated per region – 2010–2015 (MW)

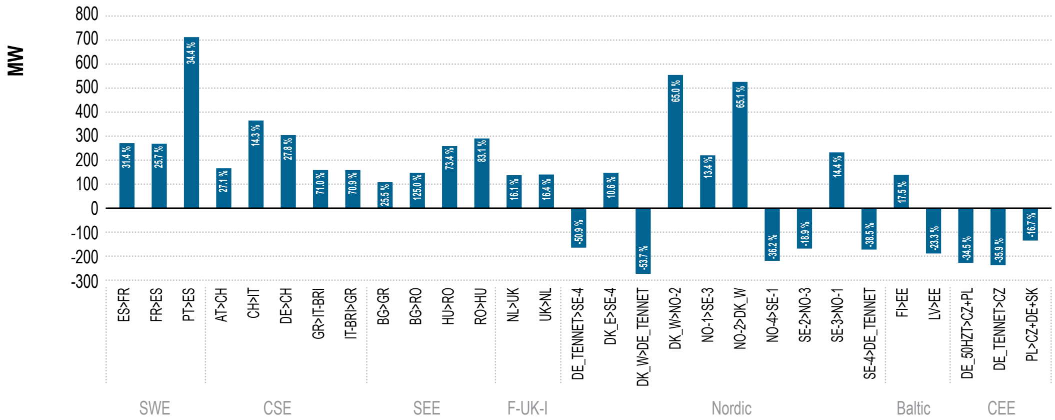


Source: Vulcanus, ENTSO-E, Joint Allocation Office (JAO) and Nord Pool Spot (2016).

Note: NTC values for all regions are available from 2011 with some exceptions[20]. In addition, 2015 NTC values in CWE region are available only until May 20.

25 Figure 10 presents the change in tradable capacities on a selection of European borders between 2014 and 2015. The largest increases were observed in the direction from Portugal to Spain and Denmark to Norway (both are attributed to new interconnectors) and the largest decreases were recorded in the exporting direction on the Northern German borders.

Figure 10: Change in tradable capacities in Europe – 2014–2015 (MW, %)



Source: Vulcanus, ENTSO-E, JAO and Nord Pool Spot (2016).

Note: The analysis includes 48 borders in Europe and is presented in Table 1 in the Annex. The figure excludes border directions where the difference in NTC between 2014 and 2015 was lower than 100 MW or the change in value was lower than 10%. The vertical axis represents the change (MW) between 2014 and 2015; the percentage presented above each bar shows the relative change for the same period.

26 An important positive development affecting tradable capacities was the launch of Flow Based Market Coupling (FBMC[21]) in the CWE region on 20 May 2015. With FBMC, the remaining margins available on critical branches (CBs) of the network are allocated to where they are most valuable. In theory, FBMC should render more tradable capacities (i.e. minimum and maximum net positions) compared to the available transmission capacity (ATC) method.

27 To assess how FBMC affected tradable capacities (i.e. import and export possibilities), the capacities limiting trade under the ATC method in 2014 can be compared to the limitations that resulted from using the FMBC method in 2015. For example, in Figure 11 the Belgian import constraint under ATC is represented by the

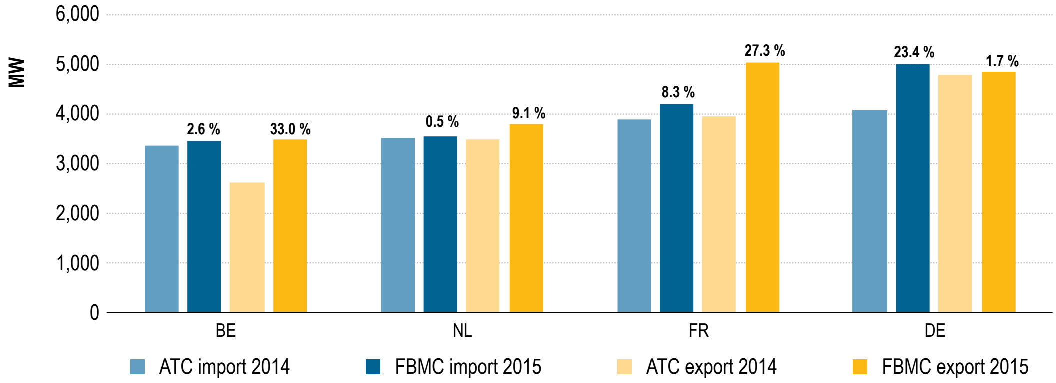
20 See 2014 MMR, page 151, which is available at: http://nra.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf.

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

aggregated NTC values from France to Belgium and from the Netherlands to Belgium, whereas the import limitation under the FBMC is now represented by either the group of remaining margins available on the CBs or additional import-export constraints that limit import/export possibilities: JAO publishes[22] these minimum and maximum net positions for each country on a daily basis.

28 Figure 11 compares the average of import and export possibilities for each country under ATC in 2014 and the FBMC method in 2015. The figure shows that all countries experienced increased import/export capacities after the implementation of FBMC, however the import to Belgium, to the Netherlands and export from Germany has increased only slightly. This development should be interpreted carefully as more years are needed to assess and conclude on the effects of FBMC.

Figure 11: Tradable capacities in the CWE region before and after implementing FBMC – 2014–2015 (MW and %)



Source: Vulcanus, ENTSO-E and JAO.

Note: The analysis is of comparable data i.e. data spanning from 20 May to 31 December 2014 for NTC and the same period in 2015 for FBMC. Percentages in the figure refer to the changes from 2014 to 2015.

29 Investments in interconnectors that have increased the volume of cross-zonal capacities in Europe in 2015 were:

- A new interconnector between France and Spain, commercial operations started on 5 October 2015, is expected to increase tradable capacities by 1,400 MW. The project is a high-voltage direct current (HVDC) link of 320 kV consisting of converter stations in Baixas (France) and Santa Llogaia (Spain);
- The Litpol link that established the first interconnection between Lithuania and Poland was commissioned in December 2015. The project is a double-circuit interconnector operating at 400 kV, and is expected to provide 500 MW of tradable capacities;
- A new 300 kV HVDC interconnector (NordBalt), partly subsea and partly underground, between Lithuania and Sweden, which was commissioned in December 2015. Since 17 February 2016, the electricity transmitted through NordBalt is traded on Nord Pool. The project is expected to increase tradable capacities by 700 MW;
- The Skagerak 4,500 kV HVDC interconnector between Norway and Denmark, operational since the end of December 2014. The project increased tradable capacities by around 500 MW; and
- The first interconnector linking Sicily to Malta, with 200 MW capacity and operating at 200 kV AC, was officially inaugurated on the 9 April 2015.

22 Data available to download at http://www.jao.eu/marketdata/implicitallocation under the CASC utility tool.

3.2 The relation between tradable and physical capacities

30 In an efficient zonal market design (i.e. if the bidding zones are properly defined), the only limiting factor to trade between two bidding zones should be the capacity of the network elements on the bidding zone borders (i.e. the interconnection lines). Therefore, the difference between the NTC and the thermal capacity of interconnectors on the existing bidding zone borders can be a starting point to assess the efficiency of current zonal delimitation. This relation can indicate the potential scope for increasing the NTC values if internal network elements were not allowed to limit cross-zonal exchanges.

31 Figure 12 presents the ratio between the average yearly NTC for 2015 (separately for both border directions) and the aggregated thermal capacity[23] of cross-zonal interconnectors in 2014[24]. The figure shows that HVDC interconnectors have higher ratio values, which is partly explained by the fact that these interconnectors are not impacted by UFs and are usually not considered in the N-1[25] security assessment. Moreover, HVDC interconnectors are less affected by the ambient (underground or subsea cables).

32 The low ratio shown in Figure 12 for HVDC interconnectors means that either the cable was not operational for longer periods (e.g. due to maintenance work) or its capacities were regularly limited to relieve congestions inside the connected zones. Figure 12 shows that the tradable capacities in the direction from Poland to Sweden and from Germany to Sweden on the HVDC interconnectors represented only 13% and 26% of physical capacity, respectively. In addition, frequent limitations on the Denmark-Swedish HVDC cables were observed, although the effect on the average tradable capacities was lower, compared to the above-mentioned borders. Tradable capacities between Greece and Italy were mainly affected by the planned maintenance in May and due to an outage[26] between October and December, when the cable was not operational.

33 Available capacities on High-Voltage Alternating Current (HVAC) interconnectors are affected by additional factors including UFs, N-1 security criterion and the higher values of reliability margins (RMs), which limit their direct comparison with HVDC interconnectors. However, Figure 12 shows that, on some borders, particularly those located on the right hand side of the chart, for both the HVAC and HVDC interconnectors, the actual NTC values are significantly lower than the physical capacity. The analysis shows that on average 84% of HVDC and 28% of HVAC interconnector's physical capacity is used for trading.

34 In addition, on borders where FBMC was implemented, the average minimum and maximum net position per country was compared to the sum of thermal capacity of interconnectors on the relevant borders. The results are presented on the right side of Figure 12 and are consistent with a per-border analysis using NTC values (presented in the figure under HVAC). Data shows that, on average, approximately 31% of the interconnector's physical capacity on CWE borders is used for trading.

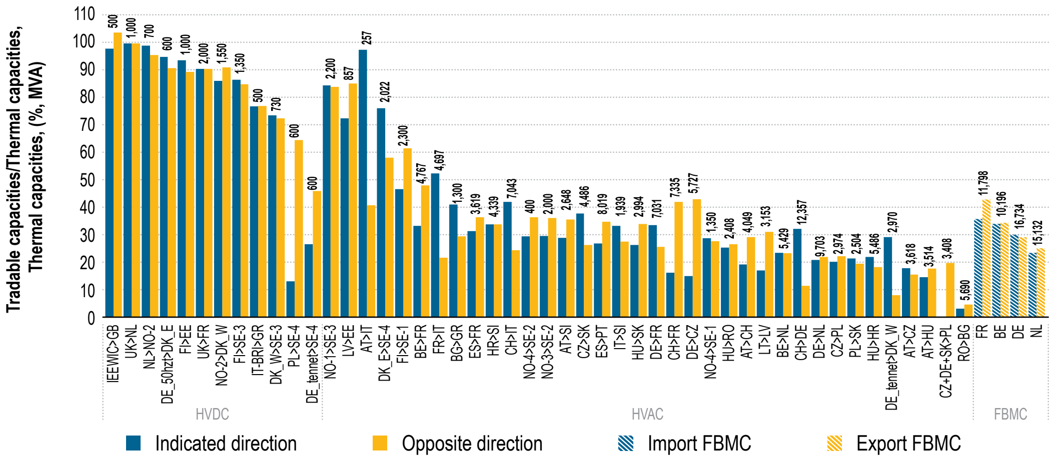
23 The thermal capacity of an interconnector, while mainly determined by physical properties, is also affected by the environment in which it operates in (i.e. temperature, wind, solar radiation, etc.). Data are available only for December 2014.

24 Publicly available data: https://www.entsoe.eu/publications/statistics/yearly-statistics-and-adequacy-retrospect/Pages/default.aspx.

25 N-1 security is used to provide protection from cascading failures in the interconnected grids. In the System Operation Guideline, the definition of N-1 criterion assumes operational security limits including voltage and system stability. For example, on long and heavy loaded transmission lines, there is a risk of cascading failures in the interconnected HVAC grid caused by these stability issues. The N-1 criterion, when applied on these interconnections, implies that tradable capacities might be reduced below the thermal constraints even if the grid is complete and there are no internal congestions. This physical phenomena affects both internal HVAC grid and interconnections. HVDC interconnectors are considered as a loss of load or/and generation in the N-1 assessment. Therefore, if internal congestion does not occur, the capacity of those interconnectors is not limited in advance in order to accommodate for the N-1 criterion.

26 See http://www.admie.gr/uploads/media/CAPACITY_AVAILABILITY_AT_GREECE-ITALY_INTERCONNECTION.pdf.

Figure 12: Ratio between available NTC and aggregated thermal capacity of interconnectors – 2014 and 2015 (%, MW, MVA)



Source: Vulcanus, ENTSO-E YS&AR (2014), EW Template (2016), Nord Pool Spot, and ACER calculations.

Note1: Forty-eight borders are included in the analysis. By default, the values for the thermal capacity of interconnectors were taken from ENTSO-E YS&AR, except for the values on Swedish-Norway borders, where the information is from NRAs, provided in the "EW template". The value of thermal capacity for the FR-ES border was calculated as the weighted average value of the periods before and after the Baixas - Santa Llogaia interconnector started commercial operation, i.e. before and after 5 October 2015.

Note 2: Average import and export capacities in FBMC countries are compared with the sum of the thermal capacity of interconnectors on the relevant borders (i.e. for Germany, interconnectors on DE-FR and DE-NL borders are considered).

35 The ratios presented above for HVAC interconnectors would be more accurate if the thermal capacity of interconnectors were reduced to account for the operational security criteria (i.e. N-1) and the uncertainty of capacity calculation (i.e. reliability margin). In order to address the first issue, the Agency has estimated the impact of applying the N-1 criterion according to a simplified methodology, developed for the purpose of this report, which takes into account only the cross-border network elements. The methodology and the underlying assumptions are presented in Annex. The results show that including N-1 criterion in the analysis would reduce the thermal capacity of HVAC interconnectors by an average of 14% and 27%, for meshed and non-meshed networks (i.e. the borders of FR-ES, ES-PT and DE-DK_W), respectively. Therefore, the results presented in Figure 12 would not change substantially.

36 However, the effect of the reliability margin (i.e. representing forecasting and modelling errors in the capacity calculation) was not estimated [27].

37 Table 1 shows the regional[28] performance of the indicator presented in Figure 12. As shown in Chapter 5, UFs have a negative impact on tradable capacities mainly in the CEE, the Central-South Europe (CSE) and the CWE regions.

27 In the future, perhaps this could be assessed with the assistance of TSOs.

28 Regions, as defined in the Regulation (EC) No 714/2009.

Table 1: Ratio between NTC and thermal capacity (regional performance) – 2015 (%, MW)

HVAC/HVDC	Region	Tradable capacities (MW)	Physical capacities (MVA)	Ratio
HVAC	NORDIC	6,164	13,242	46.5%
	BALTIC	1,431	4,010	35.7%
	CWE	7,352	26,930	27.3%
	SWE	3,687	11,638	31.7%
	CSE	12,104	42,016	28.8%
	CEE	7,493	31,873	23.5%
	SEE	2,403	14,884	16.1%
HVDC	F-UK-I	3,303	3,500	94.4%
	BALTIC	913	1,000	91.3%
	CSE	384	500	76.7%
	NORDIC	4,741	6,130	77.3%

Source: Vulcanus, ENTSO-E YS&AR (2014), Nord Pool Spot, and ACER calculations.

Note: Tradable capacities are calculated as average NTC values per border in both directions, whereas physical capacity is calculated as the sum of thermal capacity of interconnectors on the borders. These values are added together for each region. In the last column, the ratio between them is presented.

4 Congestion management methods

Chapter summary

This Chapter assesses why the level of cross-zonal tradable capacities remain moderately low and in particular explains why there is a gap between physical and tradable capacities. There are two key reasons. First, the process applied by TSOs to calculate the capacity made available for cross-zonal trade is insufficiently coordinated. In view of this, Section 4.1.1 provides an updated assessment of the fulfilment of the requirements defined for capacity calculation in the CACM Regulation. Second, within the capacity calculation, TSOs treat internal and cross-zonal flows unequally, which is explained in Section 4.1.2. Lastly, in line with last year's MMR, Section 4.2 provides an update on the costs of remedial measures that are increasingly being applied by TSOs to relieve physical congestion.

The analysis shows that the IEM could be significantly further integrated if capacity calculations were improved by better coordination and more frequently applied closer to real time, while ensuring the equal treatment of internal and cross-zonal exchanges. In order to assess this equal treatment, access to the relevant data, improvements of data definitions and the performance of the Transparency Platform need to be enhanced. In addition, to allow for a better understanding of how the applied remedial measures are affecting cross-zonal capacities, more detailed data are needed from TSOs, who should provide better reasoning for applying a specific remedial measure and its effect on cross-zonal capacity.

The CACM Regulation provides a framework that allows bidding zone configuration to adapt to the evolution of physical congestion. However, this requires the consensus of the TSOs, MS, and NRAs on methods and proposals to amend the bidding zone configuration.

4.1 Capacity calculation

4.1.1 Level of coordination between Transmission System Operators

38 The coordination between TSOs is essential for the well-functioning of the Internal Energy Market (IEM), as their actions and electricity exchanges within a control area can significantly influence physical flows and operational security in other areas. In this respect, the CACM Regulation requires coordination in the capacity calculation process within and between capacity calculation regions.

39 To assess how TSOs see their cooperation with each other, the Agency required TSOs to categorise the coordination methodologies they apply in one of four[29] possible options entailing different degrees of coordination for each timeframe. When the level of cooperation reported by two TSOs for the same border in a given timeframe was different, the lower reported level was used in the assesment, as is assumed that the coordination on a given border is only as strong as its weakest point. The benchmarking, as presented in the note under Table 2, is set against definitions developed for the purpose of this MMR which aims to monitor progress in implementing coordinated capacity calculation. The evaluation of the applied capacity calculation methodology, against the definitions presented in the note under Table 2, is qualitative by nature and therefore may suffer from different interpretations by TSOs. The Agency is committed further to improve the definitions with a view to reduce the scope for interpretation.

40 The results for 2015 are presented in Table 3 and show that, compared to 2014, the level of coordination in capacity calculation has improved slightly, mainly for the following reasons: first, in the CWE region FBMC was implemented in the DA timeframe; secondly, coordination between Baltic TSOs was improved; and, thirdly, capacity calculation in the intraday timeframe was introduced on the Danish borders with the other Nordic countries.

41 However, two main concerns limiting the performance of many borders still stand out. First, on many borders capacity calculation is simply not applied by at least one of the TSOs: out of the 48 borders assessed, this is the case on 27 borders for ID, 10 borders for DA, 8 borders for month-ahead and 3 borders for year-ahead. Secondly, on 40 out of 48 the borders, either a bilateral or partly coordinated capacity calculation method is applied. The only exceptions are the northern Italian borders, where fully coordinated (FC) NTC calculation for the yearly and monthly timeframes is applied, and the CWE region, where FBMC is implemented in the DA timeframe.

29 See note 2 under Table 2.

Table 2: Application of capacity calculation methods on different borders at different timeframes – 2015 (%)

Border	Y	M	D	ID	D/ID res.	Score	Border	Y	M	D	ID	D/ID res.	Score
AT-CH	BIL	BIL	BIL		<24	15.6%	EE-FI	PC	PC	PC	PC	24	66.7%
AT-CZ	BIL	BIL	BIL		<24	15.6%	EE-LV	PC	PC	PC	PC	<24	58.3%
AT-HU	PC	PC	PC		<24	34.4%	ES-FR	PC	PC	PC		<24	45.8%
AT-IT	FC	FC			<24	37.5%	ES-PT	PC	PC	PC		<24	45.8%
AT-SI	BIL		BIL		<24	9.4%	FI-SE1	PC	PC	PC	PC	<24	58.3%
BE-FR	BIL	BIL	FB		24	37.5%	FI-SE3	PC	PC	PC	PC	24	66.7%
BE-NL	BIL	PC	FB	*	24	43.8%	FR-IT	FC	FC			<24	37.5%
BG-GR	PC	PC			<24	25.0%	FR-UK	BIL	BIL	BIL	BIL	24	33.3%
BG-RO	PC	PC			<24	25.0%	GR-IT	BIL	BIL			24	16.7%
CH-DE	PC	PC	PC		<24	34.4%	HR-HU	BIL	BIL			<24	12.5%
CH-FR	PC	PC	PC		<24	34.4%	HR-SI	BIL	BIL			<24	12.5%
CH-IT	FC	FC			<24	37.5%	HU-RO	PC	PC			<24	25.0%
DE-PL	BIL	BIL	BIL	PC	<24	25.0%	HU-SK	PC	PC	PC		<24	34.4%
CZ-DE	PC	PC	BIL	BIL	<24	31.3%	IT-SI	FC		FC		<24	34.4%
CZ-PL	PC	PC	BIL	BIL	<24	31.3%	LT-LV	PC	PC	PC	PC	<24	58.3%
CZ-SK			BIL		<24	3.1%	NL-NO2	BIL	BIL	PC	BIL	24	41.7%
DE-DKE	BIL	BIL		BIL	24	25.0%	NL-UK	BIL	BIL	BIL	BIL	24	33.3%
DE-DKW	BIL	BIL	BIL		<24	20.8%	NO1-SE3	PC	PC	PC	PC	24	66.7%
DE-SE4			PC		24	16.7%	NO3-SE2	PC	PC	PC	PC	24	66.7%
DE-FR	BIL	BIL	FB		24	37.5%	NO4-SE1	PC	PC	PC	PC	24	66.7%
DE-NL	PC	PC	FB	BIL*	24	56.3%	NO4-SE2	PC	PC	PC	PC	24	66.7%
DKE-SE4	BIL		BIL	BIL	<24	16.7%	PL-SE4			BIL		24	8.3%
DKW-NO2	BIL		BIL	BIL	24	25.0%	PL-SK	PC	PC	PC		<24	34.4%
DKW-SE3	BIL		BIL	BIL	24	25.0%	IE-UK	BIL	BIL	BIL	BIL	24	33.3%

Source: Data provided by NRAs through the EW template (2016), EMOS, ENTSO-E (2015) and ACER calculations.

Note 1: Benchmarking: NA: not applied (0 points), BIL: bilateral NTC (1 point), PC: partially coordinated NTC (2 points), FC: fully coordinated NTC (3 points), FB: flow based (4 points). If the resolution of capacity calculation in DA in the ID timeframe was less than 24 hours (e.g. based on 24 different CGMs), the points for the ID and DA timeframe were reduced by half a point. In the case of HVDC interconnections and borders where FBMC is implemented, resolution of 24 hours was assumed a priori The sum of points for each border is divided by the maximum possible sum of points, which is 16 for borders where flow-based capacity calculation should be applied, and 12 on borders where fully coordinated NTC capacity allocation should be applied[30]. The CC method on ES-PT border is classified as PC due to the fact that it is not performed together with all the TSOs in the region.

Note 2: Descriptions of methods applied:

***Pure bilateral NTC calculation (BIL)** – Capacity calculation on a given border is completely independent of capacity calculation on any other border. Both TSOs on a border calculate the NTC value for this border based only on its own network information and, subsequently, the lower of the two values is given to capacity allocation;*

***Partially coordinated NTC calculation (PC)** – Capacity calculation on a given border is partly dependent on the capacity calculation on at least one other border. The two TSOs and the relevant TSOs of the affecting borders calculate the NTC value on this border together. At least two borders are taken into consideration, although not all significantly affected borders and networks are considered;*

***Fully coordinated NTC calculation (FC)** – The calculation of NTCs values is performed together on all borders of a specific region by the relevant TSOs by including the conditions of all significantly affected network elements in the calculation process; and*

***Flow-based capacity calculation (FB)** – This process leads to the 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 those network elements, describing how much the flows on those 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.*

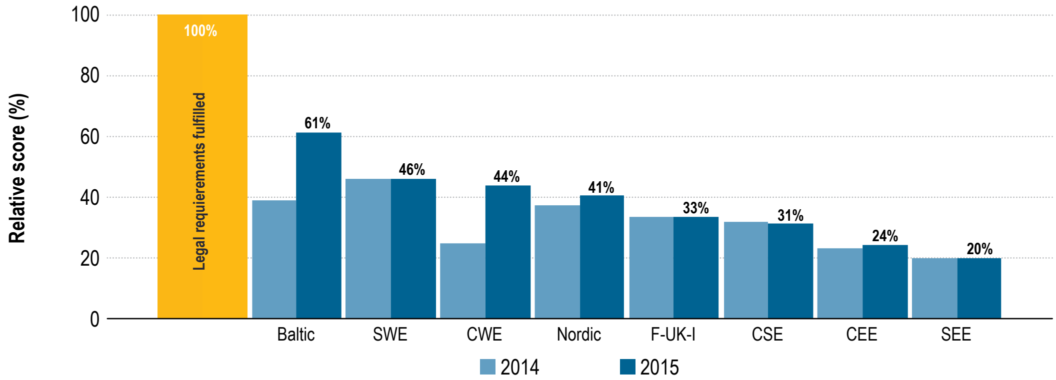
Note 3: For ES-PT the PC reported under "D" refers to weekly calculations; however, values are recalculated in the event of unexpected outages.

*Note 4: *For the Dutch borders with Belgium and Germany it is necessary to mention that an assessment is performed to offer any remaining capacities after DA FB in the ID timeframe. That is, in the Netherlands, the TSO checks schedules against available network capacity, assesses flows and compares them against the available capacity resulting from DA FB. The result of this assessment is cross-checked with other CWE TSOs to see if the updated tradeable capacities can be guaranteed. Furthermore, the Dutch TSO (TenneT) performs this assessment six times a day based on updates national schedules.*

30 The CACM Regulation requires the implementation of flow-based capacity calculation on all bidding zone borders, whereas coordinated NTC may be applied in the F-UK-I region, the Nordic and Baltic region, within Italy, the SWE region, as well as on all direct current (DC) interconnectors. Although the CACM Regulation was only recently adopted and all its provisions have not yet entered into application, similar requirements are already applicable based on Regulation (EC) No 714/2009 and Commission Regulation (EU) 543/2013. They require fully coordinated capacity calculation (either flow-based or coordinated NTC) in all timeframes (yearly, monthly, daily and ID).

42 Compared to 2014, the coordination of capacity calculation (presented per border in Table 3) has most notably improved in the Baltic and the CWE regions (see Figure 13).

Figure 13: Regional performance based on fulfilment of capacity calculations requirements – 2014–2015 (%)



Source: Data provided by NRAs through the EW template (2016) and ACER calculations.

Note: Rating in the table was calculated by adding together the scores of 48 borders according to the region of which they are part, and dividing them by the maximum score possible. The maximum score per border was set according to the CACM Regulation. The decrease in performance in the SEE region is the result of improved data reporting.

43 All in all, the degree of coordination in capacity calculation has not yet reached the level which will be required by the CACM Regulation[31] once all its provisions have entered into application. According to this indicator only four regions[32] exceeded a fulfilment level of 1/3 in 2015. This indicates that there is significant work to be done to increase coordination in capacity calculation.

4.1.2 Treatment of electricity exchanges inside and between bidding zones

44 Wholesale electricity markets in Europe are structured in bidding zones within which any consumer can contract electricity with any generator without limitations. Therefore, to ensure operational security, TSOs can only limit exchanges between bidding zones, through the capacity calculation and allocation process. Regulation (EC) No 714/2009 and, in particular, the CACM Regulation require that capacity calculation and allocation should not result in undue discrimination (i.e. the capacity of the network elements being disproportionally allocated for internal exchanges as opposed to cross-zonal exchanges). Offering less cross-zonal capacity for trade due to unequal treatment of electricity exchanges reduces the efficiency of the market and hence reduces social welfare.

45 In general, physical cross-zonal capacity (Figure 12) can be limited during the capacity calculation process, beyond what is needed for the application of N-1 criterion and a reasonable level of reliability margin, for the following three reasons:

- to accommodate planned grid maintenance works during a certain period;
- to accommodate flows resulting from internal exchanges (i.e. Loop Flows (LFs)) and flows resulting from non-coordinated capacity allocation on other borders (i.e. Unscheduled Allocated Flows (UAFs)); and
- to relieve congestion inside a bidding zone (control area).

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

32 For the purpose of the analysis, cross-zonal borders were grouped into regions which are defined in accordance with Annex I of Regulation (EC) No 714/2009 (OJ L 211, 14/8/2009), with some slight modifications. The definition applied in this section is as follows: the Baltic region (LT-LV, EE-LV, EE-FI), the CEE region (CZ-DE, CZ-SK, HU-SK, AT-SI, AT-HU, AT-CZ, CZ-PL, PL-SK), the CSE region (CH-DE, CH-IT, CH-FR, FR-IT, AT-CH, GR-IT, IT-SI, AT-IT), the CWE region (DE-NL, DE-FR, BE-FR, BE-NL), the F-UK-I region (FR-UK, NL-UK, IE-UK), Nordic (NO1-SE3, DKE-SE4, FI-SE1, FI-SE3, DKW-NO2, DE-DKW, NO3-SE2, NL-NO2, DKW-SE3, DE-DKE, NO4-SE1, DE-SE4, PL-SE4, NO4-SE2), the SWE region (ES-PT, ES-FR) and the SEE region (SI-HR, HR-HU, BG-GR, HU-RO, BG-RO).

46 Empirically disentangling these reasons would require detailed data, which are not currently available. Further analysis in cooperation with other stakeholders (i.e. TSOs, ENTSO-E and NRAs) will be undertaken by the Agency in order better to understand the reasons behind the limitations of cross-zonal capacities.

47 There are grounds to suspect that, due to the lack of correct and adequate incentives for TSOs, the latter prefer, during the capacity calculation process, to limit ex-ante cross-zonal capacities in order to limit the costs of redispatching and countertrading required to accommodate internal flows (see Section 4.2). By doing so, the potential loss of social welfare associated to reduced cross-zonal capacities is not properly accounted for. Furthermore, the loss of social welfare is not necessarily borne by a country or a region that is directly connected to the border where the cross-zonal capacity is reduced, which makes the proper internalisation of the resulting costs by TSOs even more challenging.

48 In order to provide the correct and adequate incentives for TSOs to apply actions with cross-border relevance, the costs of these should be distributed between TSOs through a cost-sharing methodology. Further, to facilitate more efficient capacity allocation, the application of remedial measures (i.e. internal and cross-zonal) in the capacity calculation should be coordinated at least at a regional level.

49 Another reason to suspect that internal and cross-zonal flows are not equally treated is elaborated in a recent report[33] published by the Swedish Regulator, the Energy Markets Inspectorate. It reports on the limitations of capacities on the borders between Germany and the Nordic countries between 2012 and 2014, and shows the impact of reduced cross-zonal trade on social welfare.

50 The frequent limitations on the borders referenced in the above-mentioned report have continued in 2015, with increased frequency and magnitude. This resulted in reduced tradable capacities (average of both directions) on the DE-SE-4 and DE-DK_W borders of 44% and 22%, respectively. The decrease of 54% in the DK_W->DE direction was especially high and resulted in the indicator presented in Figure 12, which was already low in 2014, falling further. The Denmark West – Germany border is further assessed in the case study below. It is also worth mentioning that in the Transparency Platform (TP), the hours when limitations occur are commonly reported to be “planned outages”, which is difficult to understand.

51 In addition to the borders named above, there are several examples (i.e. the Spanish-French and Polish-Swedish borders) where the first two legitimate reasons from paragraph (45) (i.e. UFs volumes and extensive maintenance periods) cannot easily explain the low ratios presented in Figure 12.

33 See http://ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter%202015/Ei_R2015_12.pdf.

Case study 1: Reductions on the Western Danish – German border (DK1-DE)

Evolution of NTCs on Danish borders

The available NTC on the DK1-DE border has continuously decreased over the past five years. In 2015, the average available capacity from DK1 to DE was 13% of the total nominal capacity (1,780 MW). This evolution partly reflects the physical challenges in the transmission system due to the significant increase of non-programmable wind-infeed in both Denmark and Germany. Insufficient internal transmission capacity in Germany and network maintenance and reinforcements are putting the German transmission grid under additional pressure.

When assessing the evolution of NTC values on the Danish borders (Figure (i)), a negative development on the DK1-DE border is noted. In the observed period, the available NTC has experienced considerable restrictions in both directions, with an exception in 2016 in the DE-DK1 direction. In 2015 the price in DK1 has been lower than the one in DE in 73% of the hours (on average by 12.6 EUR), compared to 7% where the DE price was higher than the DK1 price (on average by 7.4 EUR). Thus it is more relevant to examine the DK1-DE direction.

Figure (i): Hourly average available NTC values on DK interconnections – 2012–2016 (% of the total nominal capacity)

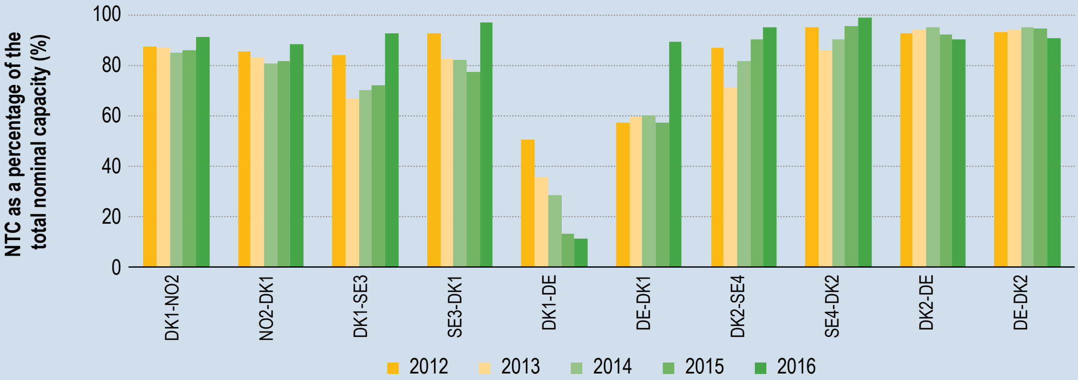
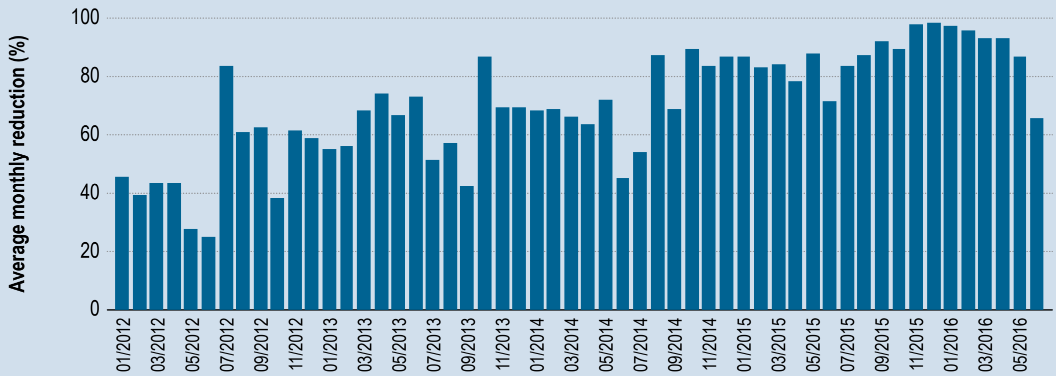


Figure (ii): Hourly average NTC reduction from DK1 to DE, per month – 2012–2016 (% of the total nominal capacity)



Source: Energinet.dk and DERA calculations.

Note: The total nominal capacity between DK1 and DE changed in October 2012 from 1,500 MW to 1,780 MW due to grid reinforcements.

Hourly average available capacity from DK1 to DE has decreased from 51% in 2012 to 11% in the first half of 2016 (Figure (ii)). A temporary improvement of NTC over the summer months can be noted which can be partly attributed to less grid maintenance and less wind production in the summer period.

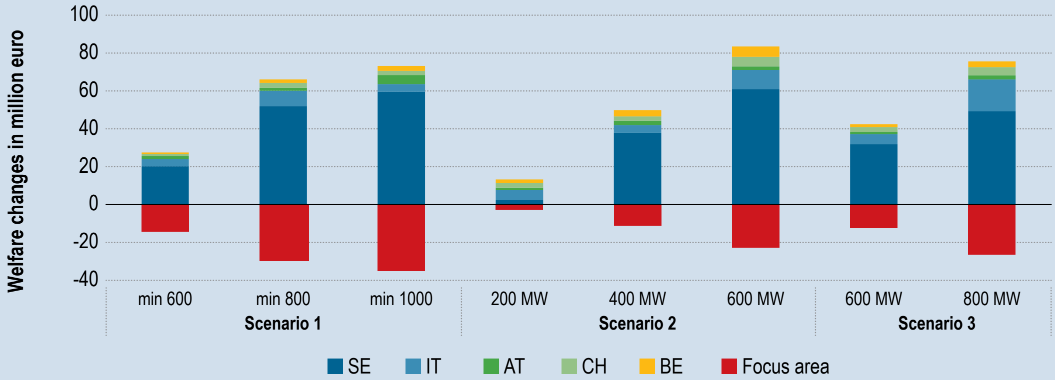
Economic effects

The difference between the historical NTC values (presented in the figures above) and the base case scenario, which assumes that the capacity on this border is limited only by the network elements on this border, presents a capacity loss. This can further lead to a social welfare loss, which can be assessed by multiplying the historical price difference between DK1 and DE, with the difference of the available capacity steaming from both scenarios, assuming there is no price elasticity.

An increase of tradable capacity from current levels to nominal higher capacity would render a social welfare benefit. However, when assessing practical solutions to increase the capacity, costs associated to making this extra capacity available (i.e. cost of remedial actions) also have to be considered.

A study by IEAW Aachen, commissioned by the Tennet TSO GmbH and Energinet.dk[34], analysed the full effects of increasing the cross-border capacity through countertrade and/or cross-border redispatching. The study, using 2012 data and analysing different scenarios, demonstrates an overall social welfare loss for the focus area (Germany and Denmark). However, on a European scale the estimated social welfare effects were positive. Figure (iii) shows the results of welfare changes for different scenarios.

Figure (iii): Welfare changes of a countertrade model for different scenarios compared to 2012 base case (euro)



Source: IAEW Aachen: Investigation of welfare effects of increasing cross-border capacities on the DK1-DE interconnector (2014).

Capacity calculation

Current capacity calculation methods (CCMs) across Europe are usually assuming that the network must accommodate all power flows resulting from internal exchanges, while cross zonal capacity and the resulting exchanges are calculated as a residual between the internal exchanges and the security limits. This situation results in discriminatory treatment between internal and cross-zonal exchanges with regard to network access.

Current practice on DK1-DE border

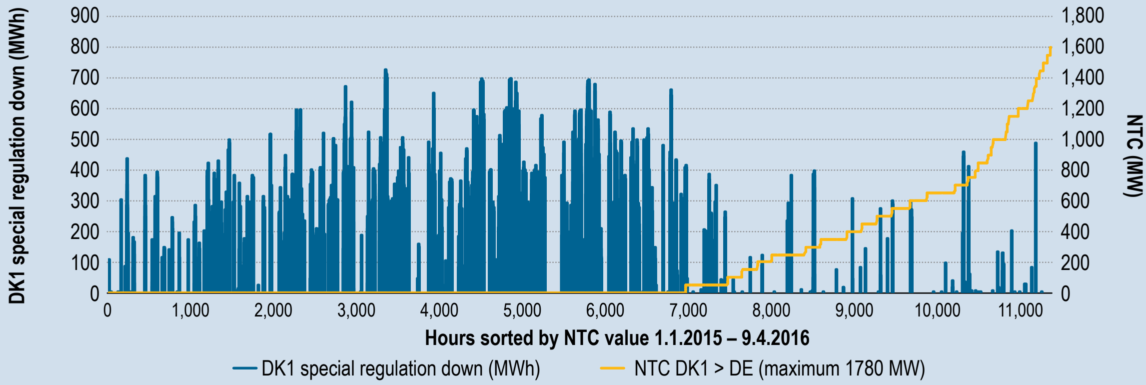
The capacity calculation on DK1-DE does not derogate to this general rule.

Indeed, in high wind situations and in order to relieve situations with excess energy in (Northern) Germany, NTC reduction is used as the primary tool to keep the German grid balanced and to enable internal exchanges arising from trade in the day-ahead market within the DE/AT/LU bidding zone – e.g. the NTC availability was only 11% on average for all hours in 2016. The maximum nominal export capacity was never available in 2016; NTC was reduced in every hour of 2016.

34 Available to download at: https://www.energinet.dk/SiteCollectionDocuments/Engelske%20dokumenter/El/Report_TenneT_Socio_Economic_DK1_DE_interconnector%20PDF.pdf.

An alternative to NTC reduction is selling excess energy – or, in other words, purchasing downward regulation – in DK1. This tool, called 'special regulation', is by definition used to assist neighbouring transmission grids (i.e. in Denmark German TSO asks the Danish TSO to sell energy on their behalf). Figure (iv) shows volume of special regulation and respective NTC for hours where the price in DK1 is lower than in DE. In situations with (some) available southbound capacity on the border (positive NTC), 'special regulation' is usually not used. On the other hand the use of special regulation was quite common in hours where NTC was zero. This indicates that 'special regulation' is mostly used as a last-resort measure when NTC reduction on DK1-DE border is not sufficient to keep the German grid balanced and to enable internal exchanges arising from trade in the day-ahead market within the DE/AT/LU bidding zone[35]. The same tool however is not used by the respective TSO to enable cross border trade. Internal and external exchanges are thus treated differently under the current CCM.

Figure (iv): Special regulation DOWN in DK1 and NTC (in hours where DK1 price < DE price) – 2015-2016



Source: Nord pool and Energinet.dk.

Possible measures to solve the apparent problem of decreasing tradable capacity

Infrastructure investment - The need for grid investments is recognised within Germany and accounted for in the Ten-Year Network Development Plan. When completed, these investments should diminish the problem and allow NTC values to go up to the nominal capacities. Grid development around the Hamburg area, as well as four planned internal DC links, are projected to solve the problem regarding NTC reductions on the DK1-DE border. Recent news on the delay of some significant infrastructure projects underline the lengthy and somewhat insecure outlook of that solution meaning that infrastructure investments can only be considered a long term solution in this case.

Bidding zones - From a theoretical viewpoint the splitting of the DE/AT/LU bidding zone could solve at least part of the challenges. The market, i.e. prices, production and consumption, would adjust according to the underlying physical grid and result in a physically feasible market outcome. However, the decision making process and implementation of a bidding zone split is unknown, which makes this a mid-term solution at best.

Cross-border redispatch/countertrade - In the short term, TSOs could make more extensive use of cross-border redispatch as a preventive measure to secure cross border capacity, similar to the current practice of using special regulation. Alternatively, some form of countertrade, for example in the intraday timeframe could be analysed further. The different conditions required for such a model, such as the availability of up- and downward regulation, as well as the expected costs and their sharing, need to be studied in order to conclude on its feasibility.

35 In 2015 on average 35,000 MWh per month was sold using this tool.

Conclusion

All benefits of the internal market cannot be achieved and delivered to European consumers without well-functioning cross-border trade. The observed reductions in tradable capacity on DK1-DE border limit the trade between the two countries and therefore pose an obstacle towards achieving a well-functioning, efficient and open internal energy market. Considerable infrastructure investments are planned within Germany in order to relieve the internal network problem. Until the necessary infrastructure development has been completed, which may take several years, an interim solution on the DK1-DE border, could be increased cross-border redispatch/countertrade, to increase NTC values in the short term.

52 In view of what has been presented above, with reasonable indications that internal and cross-zonal exchanges are not treated equally, which may result in undue discrimination, the Agency believes that there is a need for dedicated rules to avoid such undue discrimination. In addition, more information should be made available for the purpose of monitoring the reasons why tradable capacities are much lower than thermal interconnector capacities (even corrected for the N-1 criterion).

4.2 Remedial measures

53 To ensure operational security, TSOs apply different remedial measures to relieve physical congestion on their networks. Some remedial measures do not result in significant costs and are preventive (e.g. changing grid topology), while others (e.g. re-dispatching, counter-trading and curtailment of allocated capacities) come at a cost to the system or to TSOs.

54 The costs of remedial measures are more transparent and are recovered by TSOs either via network tariffs, or, in a few cases such as Austria and Portugal, via congestion rents. In both cases, costs are socialised and directly or indirectly affect the incontestable part of the end-consumers' bill and therefore limit the scope for competition in the wholesale and retail markets.

55 The use of remedial measures in Europe has become more frequent in the last few years for two key reasons. First, as bidding zones are not properly configured, these measures are increasingly used to relieve structural congestions, although, by their definition, the latter should be resolved by capacity calculation and allocation. Secondly, as the share of intermittent renewable energy production is increasing and thus making the location of network congestions more dynamic (i.e. appear in different locations) and less predictable, more TSO intervention close to real time operation is needed. In respect of these factors, Article 34 of the CACM Regulation allows the bidding zones configuration to adapt and accommodate for these changes. However, it requires the consensus of the TSOs on the methodology and the MSs, and NRAs involved on the proposal to maintain or amend the bidding zone configuration.

56 Table 3 shows the volumes and costs of congestion-related remedial measures, reported separately for re-dispatching and counter-trading for the year 2015[36]. A comparison between volumes and costs between MSs is impaired for several reasons. First, because the remuneration of activated internal or cross-zonal re-dispatching differs among MSs. The most common method used is the pay-as-bid pricing followed by the regulated pricing based on either a market price (e.g. DA price) or a cost-based pricing (e.g. remuneration for the cost of fuel and other costs related to the change in the operating schedule of the plant). Secondly, the possibility that NRAs have interpreted the questions used to collect this data differently. For example, the costs and volumes of remedial measures of conventional plants are reported by both the UK and Germany, however when remedial measures impacted RES, for instance limiting injections from wind generation, then only the volumes were reported by the German NRA (Bundesnetzagentur) and both (i.e. the costs and volumes) by the UK one. For Germany, the volumes in Table 3, under internal counter-trading, include Internal Security Sales (SiV)[37].

36 For comparison, see 2014 MMR, page 171, Table 13.

37 Sicherheitsbedingte regelzoneninterne Verkäufe (SiV): measures taken by German TSO 50Hertz in the light of the risk that the N-1 security criterion could be violated due to overload on the interconnection lines. Usually applied when the generated renewable-based energy (mostly wind) cannot be transported due to a violation of N-1 criterion or congestion.

Table 3: Network congestion related volumes and costs of remedial measures – 2015 (GWh, thousand euros)

MS	Re-dispatching GWh, thousand euros			Counter-trading GWh, thousand euros			Costs of other actions	Contribution from other TSOs	Total cost 2015
	Internal	Cross-border	Cost	Internal	Cross-border	Cost	Thousand euros	Thousand euros	Thousand euros
DE	11,127	1,601	880,500	1,914	412	26,316	5,169	0	911,985
ES	6,461	0	690,878	0	15	116	0	62	690,932
UK	6,195	0	465,503	0	3	51	0	0	465,553
PL	6,065	1,551	106,400	0	1	52	0	74,767	31,685
AT	33	267	18,334	0	1	0	7,008	-2,371	27,712
NO	0	0	19,023	0	0	579	1,477	249	20,830
NL	111	2	5,539	0	0	0	0	0	5,539
FI	62	1	2,233	0	33	1,551	0	0	3,784
CZ	130	78	1,513	0	0	0	0	-1,542	3,055
EE	0	0	0	0	60	1,746	0	0	1,746
FR	0	0	0	0	35	854	0	0	854
LV	0	0	0	0	0	709	0	0	709
HR	0	0	0	0	0	0	0	0	0
SK	NA	NA	NA	NA	NA	NA	NA	NA	NA
LU	0	0	0	0	0	0	0	0	0
SI	0	0	0	0	0	0	0	0	0
DK	NA	NA	NA	NA	NA	NA	NA	NA	NA
IT	NA	NA	NA	NA	73	NA	NA	NA	NA
CH	0	47	NA	0	153	NA	NA	NA	NA
PT	0	6	0	0	0	0	0	133	-133

Source: Data provided by NRAs through the EW template (2016).

Note: The Agency requested data for congestion-related remedial actions. Positive euro values refer to costs incurred by TSOs, and negative values to their revenues, whereas positive values for contributions refer to money received from other TSOs and negative to money paid to other TSOs. Denmark, Italy, Switzerland and Slovakia, did not provide details on costs or did not have the data available. Norway reported only on the costs of remedial actions. Countries not present in the table did not submit any remedial action data. For Germany the cost of redispatching is an estimation provided by the German NRA and includes the costs of remedial measures that impacted RES (i.e. limitations of wind generation). In addition the volumes of Internal Security Sales (SiV) are included in internal counter-trading.

57 When redispatching and countertrading to restore system security are not available, TSOs may curtail allocated capacities and owners of the transmission rights (TRs) have to be compensated. In the event of force majeure after the DA firmness deadline, market participants are entitled to the reimbursement of the price paid for the capacities during the explicit allocation process. In an emergency situation, market participants are entitled to compensation equal to the market price difference, in the relevant time-frame, between the bidding zones concerned (with the exception of SK-PL border, where special conditions[38] apply).

58 When Long-Term Transmission Rights (LTTRs) are curtailed prior to the DA firmness deadline, the draft Guideline on Forward Capacity Allocation[39] (FCA Guideline) envisages that the holders should be compensated by the relevant TSOs with the DA market price spread of relevant markets. However, the TSOs on a bidding zone border are allowed to cap the total compensation to be paid in a period to the total amount of congestion income collected on the relevant bidding zone border in the same period (i.e. on a yearly basis or on a monthly basis in the case of HVDC interconnectors). The cost of curtailments is usually divided between the TSOs according to the same sharing key that is used to split the congestion rent.

59 Figure 45 in the Annex shows, for a selection of borders, the frequency of LTTRs curtailments in 2014 and 2015 as well as the average curtailed capacity. In addition, the total costs of capacity curtailment in 2015 are compared to those in 2014 for a selection of borders in Figure 46.

38 Exceptions listed in the CEE Daily Auction Rules 2015, Art. 47.3.

39 Adopted by MSs on 30 October 2015 and available for download at: https://ec.europa.eu/energy/sites/ener/files/documents/FCA_301015_Final_Provisional_Voted.pdf.

60 The total congestion revenues in 2015 and the way in which TSOs spent them are presented in Figure 47.

61 The presented cost of the remedial measures applied by TSOs after the capacity calculation and allocation process, which are normally factored into the network tariffs, should be carefully interpreted. Efficiently applied remedial measures could contribute to EU social welfare if they rendered additional cross-zonal capacity for trade compared to when these measures are not applied. However, as the costs of remedial measures are factored into the network tariffs, they affect location signals. To assess the efficient level of remedial measures, one needs, ideally, to perform counterfactual simulation analysis based on comprehensive and detailed data, including on networks and generation. The Agency does not have these data, nor does it have detailed simulation tools to perform these counterfactual analyse. However, the Agency remains committed to providing in the future further analysis. Finally, although the cost of remedial measures are difficult to compare across MSs, they are more transparent than the loss of efficiency due to reducing tradable capacities in the capacity calculation and allocation process.

5 Unscheduled flows and loop flows

Chapter summary

Unscheduled flows usually reduce the amount of tradable cross-zonal capacity and consequentially affect the social welfare distribution in Europe. Therefore, monitoring these “distortive flows” (i.e. identify their location in the network and show their magnitude) is important for assessing market efficiency and integration. Additionally, it provides an indication on which adequate remedies can be recommended.

This Chapter provides an update on the evolution of unscheduled flows in 2015 (Section 5.1) and their likely impact on cross-zonal capacities and social welfare (Section 5.2).

As shown in previous MMRs, unscheduled flows present a challenge to the further integration of the Internal Energy Market. Their persistence reduces tradable cross-zonal capacity, market efficiency and network security. Results from the analysis in this Chapter demonstrate that social welfare losses due to unscheduled flows have increased in 2015 to 1,137 million euro. Loop flows and unscheduled allocated flows represent 40% and 60% of the total social welfare losses due to unscheduled flows, respectively.

In the Agency’s view, the impact of unscheduled allocated flows can be mitigated by improving the capacity calculation methodology. The impact of LFs can be mitigated, in the medium term, by avoiding different treatment of flows in the capacity calculation and by improving the bidding zone configuration; and they can be alleviated, in the longer term, by investments in the transmission network. Moreover, the calculated welfare losses due to loop flows can be used to provide a starting point for developing a short-term solution for addressing the distributional effects of loop flows.

Finally, improved transparency should allow data on distortive flows to be used for a more adequate assessment of the impact of reductions in cross-zonal capacity on welfare.

5.1 Unscheduled flows

62 UF usually reduce the amount of tradable cross-zonal capacity and consequentially affect the social welfare distribution in Europe. They result from the fact that power flows on the network do not exactly follow contractual paths. The Agency has been monitoring the evolution of UFs in Europe (i.e. on the borders in the CEE, CSE and CWE regions[40]) for the past four years. Since 2012, UFs have increased by 20%, from 129.6 TWh to 155.5 TWh in 2015.

40 In Regulation (EC) No 714/2009, regions are defined in terms of countries. Therefore, the German-Austrian border could be attributed to the CEE region and CSE region. While on this border no capacity allocation takes place, UFs can be calculated. For the purpose of this MMR, these flows have been assigned to the CEE region. Moreover, within a bidding zone, UFs cannot be divided into LF and UAF and, therefore, the German-Austrian border has not been included in the subsequent analysis in this Chapter. The border between Italy and Greece is a part of CSE region. However, since they are connected through a DC cable, this border is not relevant for further UFs analysis.

63 The definitions of the flows used in this Chapter include three primary flow definitions[41], i.e. physical flows (PFs), schedules (SCHs[42]) and allocated flows (AF[43]), and three secondary definitions. PFs are measured and SCHs are provided by market participants, whereas AFs need to be calculated from the final net position of each bidding zone and the PTDF values. The secondary definitions refer to flows which are calculated on the basis of primary flows, as presented in Table 4.

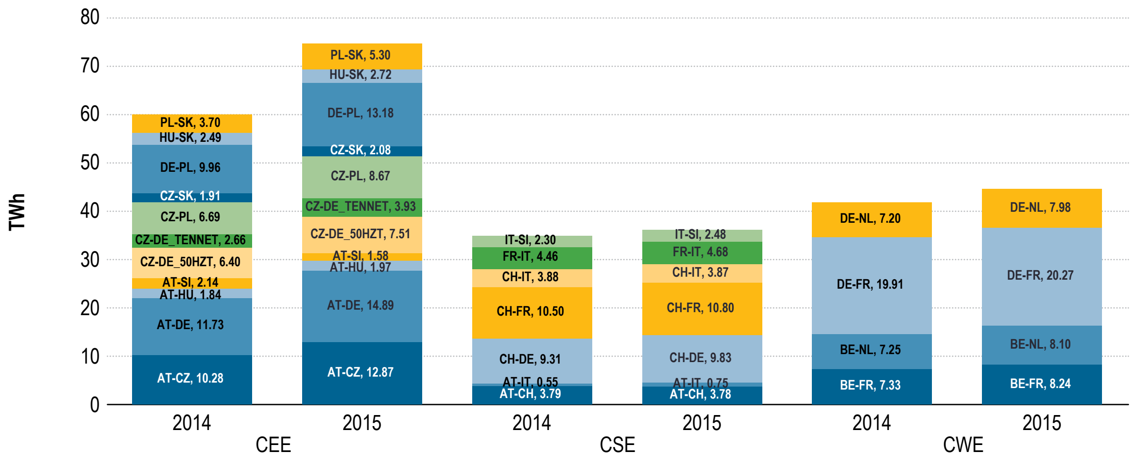
Table 4: Calculation of secondary definitions

The secondary definitions
UF = PF – SCH
LF = PF – AF
UAF = AF – SCH = UF – LF

64 The data on the AFs, used in the analysis of this Chapter was provided to the Agency by ENTSO-E. AFs were calculated on an hourly basis using some simplifications[44]. The obtained AFs data can, because of simplifications used, only be considered as a proxy for the total amount of AFs (and indirectly LFs and UAFs) observed on each border.

65 Figure 14 shows the evolution of the aggregated sum of UFs volumes in the three regions in 2014 and 2015[45]. The highest increase can be observed in the CEE region, where volumes increased by 24.9%, to 74.7 TWh in 2015. This suggests that network conditions are becoming increasingly unpredictable and, therefore, more challenging for TSOs to manage. A similar conclusion can be drawn for the CSE and the CWE regions. However, the increase was lower at 4% and 7%, to 36.2 and 44.6 TWh, respectively. Across the three regions, CEE, CSE and CWE, the volume of UFs increased by 14.1% from 136.2 TWh in 2014 to 155.5 TWh in 2015.

Figure 14: Absolute aggregate sum of UFs for three regions – 2014–2015 (TWh)



Source: Vulcanus (2015) and ACER calculations.

Note: The calculation methodology used to derive UFs is the same as that used for previous MMRs. 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.

41 For more on physical power flow definitions currently being used in the ENTSO-E community, please see https://www.entsoe.eu/Documents/MC%20documents/150929_Joint%20Task%20Force%20Cross%20Border%20Redispatch%20Flow%20Definitions.pdf.

42 SCH is a declared flow resulting from a scheduling process and is subject to an electricity exchange between two different control areas and/or bidding zones.

43 Schedules create Transit Flows and/or export/import flows in a meshed HVAC interconnection. The sum of these flows on a border are the Allocated flows. See footnote 43.

44 First, only three different sets of PTDFs, representing different seasons (Winter 2015, Summer 2015, Winter 2016), were used. Second the resulting flows on each interconnector were aggregated per border. Third, PTDFs were calculated using the proportional generation shift keys (GSK).

45 For a comparison with previous years, see the 2012 MMR, page 100, 2013 MMR, page 150 and 2014 MMR, page 165.

66 When comparing the data on a border-by-border basis, the most notable increase in the volume of UFs was observed on the CZ-DE_Tennet (+47.7%) control area border, and on the Polish-Slovakian (+43.2%), German-Polish (+32.4%), Polish-Czech (+29.6%), Austrian-German (+27%) and Austrian-Czech (+25.2%) borders, with the only significant reduction occurring on the border between Austria and Slovenia (-26.2%).

67 Separating UFs into its LFs and UAFs components shows that the aggregated absolute value of LFs amounted to 87 TWh (from 86.5 TWh in 2014), while UAFs increased to 104.6 TWh in 2015 (from 96.3 TWh in 2014).

68 The prevailing directions of UFs in 2015, as well as the average values[46] per border, are presented in Figure 15. The overall pattern of the flows still shows significant UFs volumes flowing in two major loops. The one in the east consists of UFs flowing in the loop between the northern Germany, Poland, the Czech Republic and Austria, while for the one in the west UFs are flowing between northern Germany, the Netherlands, Belgium, France and southern Germany. The extent to which UFs follow this pattern changes between winter and summer periods, due to seasonal variations in the output from wind plants, concentrated mostly in the north of Germany, and solar plants, concentrated mostly in the south of Germany. In addition, another loop of UFs can be observed flowing between eastern France to southern Germany and Switzerland. A more in-depth analysis on how UFs impact cross-border tradeable capacities in the CEE region is presented in the Agency's Opinion[47] No 09/2015.

Figure 15: Average UFs for three regions – 2015 (MW)

Source: Vulcanus (2015) and ACER calculations.
Note: Average UFs are average hourly values in 2015.

69 These flows, combined with the uncertainty of their occurrence, contribute to the reduction in the amount of cross-zonal capacity offered to the market. This, in turn, causes social welfare losses, which are detailed below.

46 For a comparison, see 2014 MMR, page 165.

47 The Opinion is available for download at: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2015.pdf.

5.2 The loss of social welfare induced by unscheduled flows

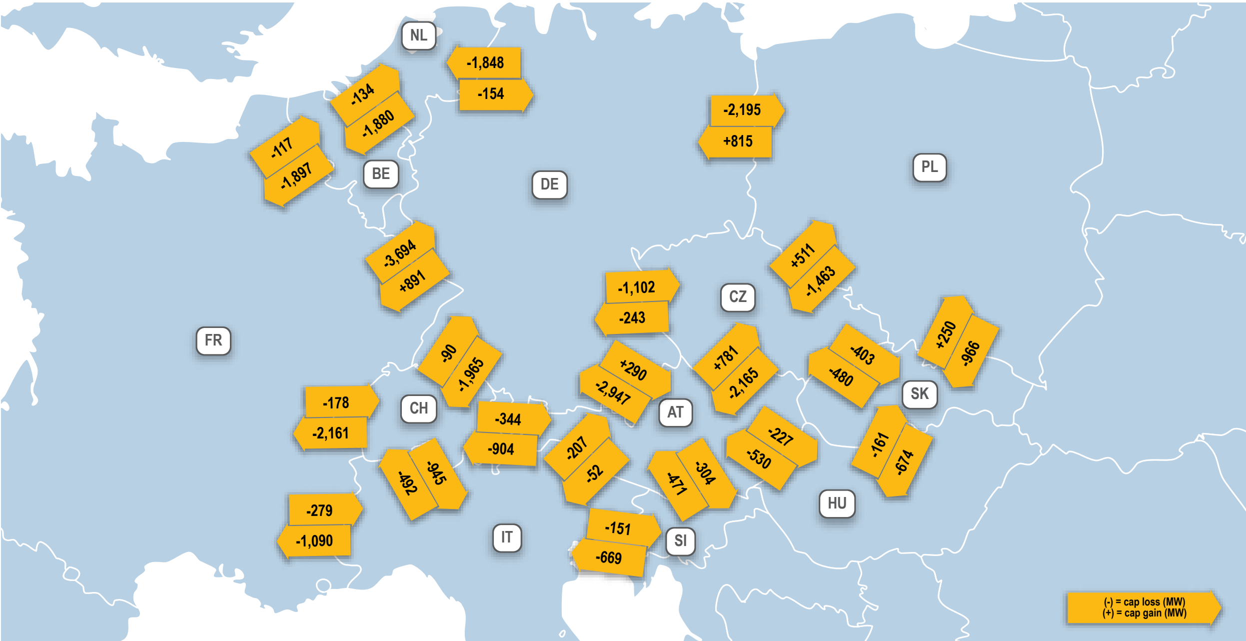
70 As more detailed data become available over time, the methodology for calculating the capacity loss and its corresponding social welfare loss is also being adapted, in order to better represent the overall loss induced by UFs.

71 The methodology[48] used for assessing the social welfare loss in this Chapter is identical to the one used in last year's MMR. It calculates the capacity loss on each border steaming from the UFs and multiplies it with the price difference on that border.

5.2.1 Loss of cross-zonal capacity due to unscheduled flows

72 In order to show the magnitude of the impact of UFs (see Figure 48 in the Annex on the methodology to estimate UFs) in terms of cross-zonal capacity losses or, in some cases, theoretical capacity gains, Figure 16 presents both values separately for all directions. It shows that the highest capacity losses occur on borders with a high level of UFs: in the east, on the DE-PL, PL-CZ, DE-CZ and CZ-AT borders and, in the west, on the DE-NL, NL-BE and BE-FR borders. High capacity losses are also observed on the FR-DE, CH-FR and DE-CH borders. Theoretical capacity gains were noted on some borders with the highest UFs in the opposite direction, i.e. on the DE-FR, AT-CZ, PL-DE, CZ-PL and SK-PL borders.

Figure 16: UFs with a mainly negative impact on cross-zonal trade – 2015 (average capacity loss/gain in MW)



Source: Vulcanus, EMOS, ENTSO-E (2015), and ACER calculations.

Note: The results can be interpreted as follows: on the German-Polish border, UFs are having a negative impact on cross-border capacity in the direction from Germany to Poland (-2.195 MW) and a positive impact in the direction from Poland to Germany (815 MW). The capacity losses/gains can be observed in both directions, because the uncertainty of forecasted UFs requires reliability margins to be taken into account in both directions of the interconnection.

73 The capacity losses shown in Figure 16 are much higher than the actual level of UFs, which are presented in Figure 15. Both figures illustrate that, on average, the value of the RM tends to be approximately similar to the average volume of UFs, but some noticeable differences among borders can be observed. For example, the DE-NL, NL-BE, BE-FR and CH-DE borders are much more affected by the uncertainty of UFs (i.e. they show high RMs), while DE-PL, PL-CZ and CZ-AT are more affected by the absolute value of UFs (rather than their uncertainty).

48 For a detailed description of the methodology used to calculate welfare losses due to UFs, see 2014 MMR, Annex 10.

74 Finally, when the capacity losses on the borders are added to the observed NTC values, they are still considerably lower than the observed thermal capacity of the interconnectors, presented in Figure 12. However the effect of the application of the N-1 criterion and of RMs must also be considered. This indicates that the calculated capacity losses are not overestimated and that, besides these capacity losses, other factors (i.e. beyond the application of the N-1 criterion and RMs) further reduce the cross-zonal capacity offered for cross-border trade.

75 As shown in Figure 16, the UFs can cause capacity loss or gain. However, the capacity gain induced by UFs is only theoretical and has not been materialised. For this reason, theoretical net capacity gains were not considered in the subsequent analysis of welfare losses. Nevertheless, when capacity losses due to UFs are divided into LF and UAF parts, one of the two parts can actually create capacity gains, which are considered in the following analysis.

5.2.2 Loss of welfare due to unscheduled flows

76 The capacity loss resulting from UFs, as assessed above, is divided into LF and UAF components. These, multiplied by the positive price difference between the bidding-zones, represent the corresponding social welfare loss (i.e. only losses due to trade restrictions form UF are considered and all other things equal). The calculations are subject to some under- and overestimation, which are commented in last year's MMR[49]. The extent of their influence on the results is hard to gauge.

77 The results[50] of the estimated welfare losses due to UFs, LFs and UAFs on the borders of the CEE, CSE and CWE regions are presented in Figure 17. The analysis shows that the total welfare loss due to UFs increased to 1,136.8 million euros in 2015. In general, this can be attributed to both the increased volume of UFs and the increase in the price differentials between zones.

78 Compared to 2014, the estimated welfare losses increased most on the CH-DE (118 million euros), CH-AT (38 million euros) and BE-NL (90 million euros) borders. Furthermore, this analysis illustrates that these increases are mainly attributable to the increased price differentials between the markets. The most notable decrease was on the DE-PL (-39 million euros) and DE-FR (-31 million euros) borders, attributable mostly to the increased price convergence.

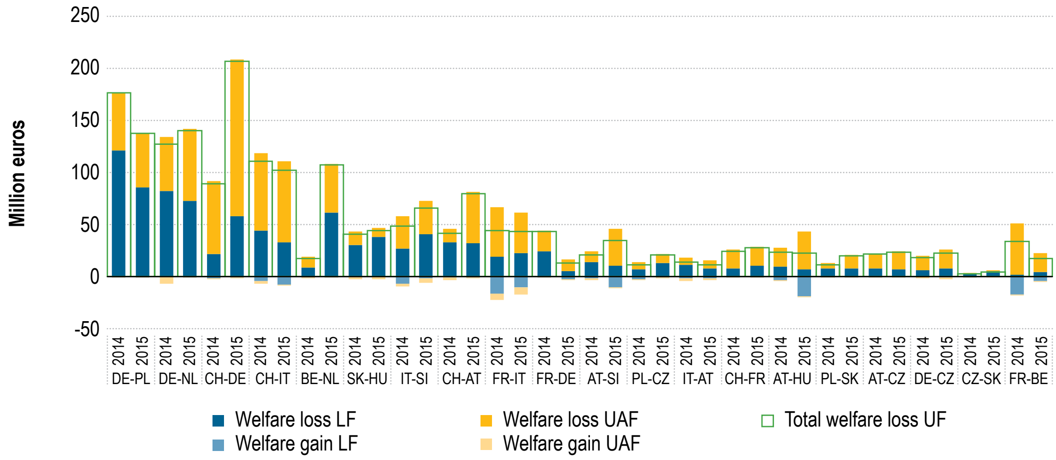
79 The total loss induced by LFs amounted to 521.4 million euros, and was partially offset by welfare gains of 67.3 million euros, resulting in a net loss of 444.7 million euros. The share of welfare losses due to LFs was 39.9%, which represents a slight decrease compared to the results from previous years. The highest losses were observed on the DE-PL, DE-NL and CH-DE borders, while positive effects have been observed on the FR-IT and CH-IT and, to a lesser extent, the FR-BE and FR-DE borders.

80 The welfare loss induced by UAFs amounted to 709.4 million euros, and was partially offset by welfare gains of 26.7 million euros, resulting in a net loss of 682.7 million euros. The highest losses were observed on the CH-DE, NL-DE and CH-IT borders, while most notable gains have been observed on the AT-IT and IT-SI borders. The detailed statistics on flows and welfare effects are presented in Table 10, Table 11 and Table 12 in the Annex.

49 See 2014 MMR, page 168, paragraph 429.

50 See Table 10 in the Annex.

Figure 17: Estimated loss of social welfare due to UFs on selected borders in the CEE, CSE and CWE regions – 2014–2015 (million euros)



Source: Vulcanus, EMOS, ENTSO-E (2015) and ACER calculations.

Note: The German-Austrian border is omitted from this figure, as Austria and Germany form a single bidding zone and have one common price reference. The German-Czech border uses one aggregated value of UAFs for both of its interconnectors. Price in Northern Italy zone was used for the DA price reference on the Italian borders. LFs and UAFs then partially offset one another in volumes and thereby the presented result should be interpreted with caution.

6 Forward markets

Chapter summary

Competitive and liquid forward markets are essential for market participants to hedge their short-term price risks. Efficient hedging opportunities are important for facilitating market entry, for example, which improves the level of cross-zonal competition.

This Chapter presents an update on the level of liquidity of European forward markets (Section 6.1) and the risk premium paid for the available instruments for cross-border hedging in Europe (Section 6.2).

The analysis shows that, in general, the liquidity of forward markets in Europe remained low in 2015, with the main exceptions being Germany, the Nordic area, France and Great Britain. The highest growth in the same period was recorded in the French forward market.

The persistence of high absolute values of assessed risk premia in the valuation of transmission rights and of Electricity Price Area Differentials point to different problems in the markets for these products, which are crucial for efficient cross-border trading. For instance, transmission right prices reflect inefficiencies such as lack of market coupling, the presence of curtailments in combination with weak firmness regimes, and periods of maintenance reducing the offered capacity, which dampen the value of transmission rights. Some other aspects, such as uncoordinated national energy policies (e.g. on the application of environmental levies to energy consumed in Great Britain, which do not apply in France and the Netherlands) distorting the price formation of transmission rights are also highlighted. In the case of Electricity Price Area Differentials, the analysis identified potential cases of limited liquidity and reduced competition in the supply of these products, due to a lower number of producers that can ‘safely' sell Electricity Price Area Differentials in some bidding zones. These cases need to be further assessed following the entry into force of the Guideline on Forward Capacity Allocation.

6.1 Liquidity in European forward markets

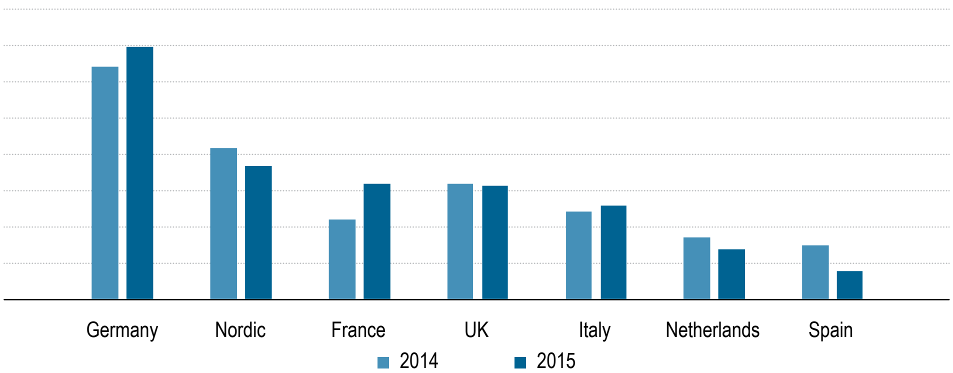
81 Market liquidity can be measured in several ways. A frequently used metric of liquidity is the "churn factor", i.e. the volumes traded through exchanges and brokers expressed as a multiple of physical consumption. There is no consensus on the level of churn factor that indicates sufficient market liquidity. However, based on the views of different stakeholders[51], a churn factor of three is considered to be a minimum value.

82 Figure 18 presents the churn factors in a selection of the largest European forward markets in 2014 and 2015. Based on the threshold mentioned above, this figure suggests that liquidity is limited in most European forward markets, with the exceptions of the German, Nordic, French and British ones.

83 Further, Figure 18 shows that Germany consolidated its position as the most liquid electricity forward market in Europe, with an increase in liquidity of approximately 9% between 2014 and 2015. The highest growth in the same period was recorded in the French forward market, with an increase in liquidity of almost 50%. The biggest reduction was recorded in Spain (-50%).

84 Several factors contributed to the increase in liquidity in the French forward market. In recent years, the main driver appears to have been the relatively low wholesale market prices compared to the price under the "Regulated Access to Incumbent Nuclear Electricity" (ARENH[52]). Since 2014, wholesale market prices in France have often been below the level of ARENH, and buyers (e.g. independent suppliers) tend to source energy and hedge risks directly in the market rather than buying energy from the incumbent (Électricité de France) at ARENH levels.

Figure 18: Churn factors in a selection of European forward markets – 2014 and 2015



Source: "European Power Trading 2016" report, © Prospex Research Ltd, March 2016.

Note: The figure shows estimates of total traded volumes in 2014 and in 2015 as a multiple of 2014 consumption from Eurostat. For copyright reasons the vertical axis is not shown.

85 The decline of liquidity in Spain is primarily due to the abolition of the auctions that until 2013 had set the wholesale price reference which was used to calculate the regulated retail price for small consumers. These auctions attracted the participation of speculative traders in forward markets. With the abolition of the auctions, these traders (and in general, financial traders) have progressively been leaving the Spanish forward market since 2014, more intensively in 2015. However, a recovery of liquidity was observed in the Iberian market in early 2016.

51 For example, see page 13 in the "Report on the influence of existing bidding zones on electricity markets" at http://www.acer.europa.eu/official_documents/acts_of_the_agency/publication/acer%20market%20report%20on%20bidding%20zones%202014.pdf.

52 ARENH is a right that entitles suppliers to purchase electricity from EDF at a regulated price in volumes determined by the French energy regulator, CRE.

6.2 Risk premia of cross-border hedging instruments in Europe

86 In the context of a limited number of liquid forward markets in Europe, the cross-border access to these markets becomes particularly important. The cross-border access to forward markets depends on the market design[53]. In most of Europe the cross-border access to forward markets is based on TRs, either physical (PTRs) or financial (FTRs), issued by TSOs which enable market participants to hedge short-term price differentials between two neighbouring zones. In the Nordic and Baltic markets and within Italy, cross-border access to forward markets is based on contracts which cover the difference between the relevant "hub" price[54] (which represents the forward price reference for a group of bidding zones) and each specific bidding zone price. Examples of these contracts are the so-called Electricity Price Area Differentials (EPADs) in the Nordic and Baltic markets or FTRs within Italy.

87 As presented in previous MMRs, an efficient market should not facilitate any significant arbitrage opportunities for strategic market players in the long-run. In order to assess this for cross-border hedging instruments (TRs or EPADs), the deviation of the prices of these instruments from the related DA price differentials needs to be checked. A measure of this deviation can be provided by the observed *ex-post* risk premia[55]. Both high positive and high negative risk premia are an undesired outcome for different reasons. High positive risk premia may constitute a barrier to new suppliers[56] while high negative risk premia may result (in the case of TRs) in the socialisation of the premia through network charges[57].

6.2.1 Risk premia of Transmission Rights

88 Table 5 presents the *ex-post* risk premia for the different TRs traded in a selection of European borders from 2009 to 2015.

53 More details on existing forward market designs can be found in the 2014 MMR, pages 175-176.

54 For example, the system price in the Nordic and Baltic areas or the PUN price in Italy.

55 This is defined as the difference between the price of the product (TR or EPAD) and the realised delivery-dated spot price differentials, i.e. the expected value or cash flow that a product can deliver to a buyer of the product.

56 This is because suppliers may find it is too expensive to hedge their procurement costs compared to cheaper options that are accessible only to established market participants.

57 This is because the related reduction in congestion revenues (in the case of TRs) is likely to be socialised (i.e. cost-reflectivity principles are not applied) and borne by network users through network tariffs.

Table 5: Discrepancies between the auction price of TRs (monthly auctions) and the DA price spreads for a selection of EU borders – various periods 2009–2015 (euros/MWh)

Border-direction	Implicit /Explicit DA allocation	Period analysed	Average-auction price	Average value of capacity (based on DA spreads)	Ex-post risk premium for the analysed period	% of periods of curtailments	% of maintenance periods	Ex-post risk premium for 2015
GR>IT	E	2012-2015	4.1	12.11	-8.0	9.2%	5.0%	-2.2
FR>IT	I	2011-2015	14.3	18.4	-4.1	2.0%	17.8%	-3.5
AT>IT	I	2013-2015	17.0	20.3	-3.3	7.0%	18.3%	-3.8
AT>HU	E	2011-2015	6.3	9.6	-3.2	0.0%	9.4%	-1.8
IT>GR	E	2012-2015	1.4	4.57	-3.1	8.7%	5.0%	-2.6
CH>IT	E	2011-2015	11.8	14.8	-3.0	8.5%	16.5%	-0.6
AT>SI	E	2011-2015	6.5	9.0	-2.4	0.0%	10.6%	0.6
FR>ES	I	April 2014-2015	11.6	13.9	-2.4	0.4%	19.0%	-1.8
DK2>DE	I	2014-2015	3.3	5.4	-2.0	0.4%	2.4%	-3.5
PL>SK	E	2011-2015	1.4	3.1	-1.7	0.0%	6.2%	-1.5
PL>CZ	E	2011-2015	1.5	3.1	-1.6	0.0%	2.0%	0.1
AT>CZ	E	2011-2015	0.1	1.6	-1.5	0.0%	3.8%	-0.7
SK>HU	I	2011-2015	5.1	6.6	-1.5	0.0%	13.9%	-2.1
CZ>DE	E	2011-2015	0.6	2.1	-1.5	0.0%	0.4%	-1.8
DE>CZ	E	2011-2015	0.1	1.6	-1.5	1.1%	0.0%	-1.1
SI>IT	I	2011-2015	12.5	13.9	-1.3	1.9%	21.1%	-4.0
DK1>DE	I	2011-2015	3.0	4.3	-1.3	0.0%	20.4%	NAP*
CZ>AT	E	2011-2015	0.6	1.9	-1.3	0.0%	8.5%	-0.4
DE>NL	I	2009-2015	5.4	6.5	-1.1	0.0%	0.0%	-0.8
DE>CH	E	2011-2015	6.3	7.4	-1.1	0.3%	0.0%	-3.0
PL>DE	E	2011-2015	2.3	3.2	-1.0	0.0%	0.0%	0.1
CH>DE	E	2011-2015	0.1	1.0	-1.0	0.0%	0.0%	-1.0
AT>CH	E	2011-2015	6.3	7.2	-0.9	0.1%	0.0%	-2.4
HU>AT	E	2011-2015	0.3	1.2	-0.9	0.0%	6.5%	-0.4
SI>AT	E	2011-2015	0.1	0.9	-0.8	0.0%	3.6%	-0.4
CH>AT	E	2011-2015	0.1	0.9	-0.8	0.2%	0.0%	-0.3
BE>NL	I	2009-2015	1.7	2.3	-0.6	0.0%	0.0%	-0.6
DE>DK1	I	2011-2015	1.0	1.3	-0.4	0.3%	15.4%	0.0
HU>SK	I	2011-2015	0.1	0.4	-0.3	0.0%	9.4%	0.0
FR>DE	I	2009-2015	1.1	1.3	-0.3	0.0%	0.0%	0.3
IT>CH	E	2013-2015	0.0	0.3	-0.2	0.1%	0.0%	-0.5
NL>DE	I	2009-2015	0.1	0.3	-0.2	0.0%	0.0%	-0.1
IT>FR	I	2011-2015	0.3	0.4	-0.1	0.2%	0.0%	0.0
BE>FR	I	2009-2015	0.9	1.1	-0.1	0.3%	NA	-0.3
DE>FR	I	2009-2015	4.6	4.7	-0.1	0.0%	0.0%	-0.9
IT>SI	I	2011-2015	0.1	0.2	-0.1	1.0%	0.0%	-0.6
IT>AT	I	2013-2015	0.0	0.1	-0.1	5.5%	0.9%	0.0
GB>FR	I	2015	0.1	0.15	-0.1	25.3%	6.2%	-0.1
ES>PT	I	2014-2015	0.1	0.2	0.0	0.0%	NA	0.1
ES>FR	I	April 2014-2015	1.5	1.6	0.0	1.7%	14.4%	0.0
GB>NL	I	2015	0.1	0.07	0.0	0.6%	0.0%	0.0
PT>ES	I	2014-2015	0.1	0.1	0.0	0.0%	NA	0.1
FR>BE	I	2009-2015	2.7	2.6	0.1	0.0%	NA	1.4
NL>BE	I	2009-2015	2.1	1.7	0.3	0.0%	0.0%	0.0
DE>DK2	I	2014-2015	2.0	1.5	0.5	0.4%	2.4%	0.2
NL>GB	I	2015	21.7	15.7	6.0	0.9%	0.0%	6.0
FR>GB	I	2015	23.8	17.4	6.5	27.9%	6.2%	6.5

Source: CAO, CASC, JAO, Common FUI Portal and Platts (2016) and ACER calculations.

** No monthly offered capacity in 2015.*

Note 1: The analysis covers the periods indicated for each border in the third column. The average auction price is the average value of all monthly auctions in the period indicated. The average price spread is the average difference of DA prices for all hours when the price differential was in the economic direction (otherwise, the value taken is zero, since the analysed TRs are options). The "% of maintenance periods" (or unavailable periods) represent periods where the capacity offered in the auction is reduced to a value below the nominal capacity of the auction, including a reduction to zero. These periods are included in the specification, and were factored in the calculations by modifying the average DA prices as described below. The last column shows risk premia for 2015 only.

Note 2: The "percentage of periods of curtailments" represents the percentage of hours when any CB capacity already allocated (before or after nomination) was partially or totally cancelled.

Note 3: During maintenance periods, the share of unavailable capacity reduces the DA value of capacity during those hours (e.g. if the capacity is reduced to half the nominal value, the price to be paid to a PTR holder that does not exercise its right according to the Use-it-or-Sell-It (UIOSI) condition, hence the value of capacity, is also equal to half the price spread).

Note 4: On the Spanish-Portuguese border, the values are based on the results of the closest-to-delivery quarterly auctions of FTRs.

89 Overall, the results presented in Table 5 confirm that, on average, PTR auction prices on most borders continued to be below the recorded DA price spreads in 2015. Furthermore, the results in Table 1 suggest that the three relevant factors that negatively affect the value of TRs are the lack of market coupling[58], the probability of curtailments and the periods of maintenance.

90 The first factor should be addressed immediately, with the completion of the DA market coupling project across the EU. The impact of curtailments should be mitigated by the implementation of stronger firmness regimes as envisaged in the draft FCA Guideline[59].

91 Periods of maintenance (also known as 'reduction periods' or periods of unavailability) seem to significantly reduce the value of TRs. This can be explained by the fact that a TR that is subject to reduction periods does not fully meet market participants' needs. In this case, market participants would remain exposed to risks during those periods, which unavoidably reduces the value of the product[60].

92 There are various ways of mitigating the impact of maintenance periods in risk premia. One possibility is to ensure that maintenance is scheduled when the impact on prices is likely to be lower (e.g. during periods of lower demand). Another (complementary) measure would be to ensure that the capacity offered by TSOs in a given timeframe does not exceed the maximum amount that can be offered even during maintenance periods, offering the remaining capacity through separated products in the same timeframe or simply leaving the remaining capacity for subsequent timeframes. On the one hand, this would increase the value of TRs and on the other, this may shift some capacity from long-term to closer-to-delivery timeframes, including the DA timeframe. The potential benefits of this measure would need to be assessed on a border-by-border basis.

93 Other factors impacting risk premia may need to be addressed locally. For example, on the Greek-Italian border, traders exporting from Greece (and, in general, all market participants buying energy in the Greek wholesale market) pay charges in addition to the wholesale market price (the so-called system marginal price, SMP). These charges are laid down in the Greek wholesale electricity market arrangements. As traders exporting energy from Greece factor these charges in their bids to procure TRs, this would explain the relatively high discrepancy between the auction prices of TRs and the day-ahead price differentials between Italy and Greece. In addition, the fact that the precise value of these charges is known only ex-post, induces a risk for traders, which factor this uncertainty in their bids to buy TRs. The magnitude of these charges has recently decreased, which would explain the decline in the absolute value of the risk premia in 2015 compared to the average absolute risk premia on the Greek-Italian border in recent years.

94 Finally, the only two borders with a noticeably positive risk premia are the British borders with France and the Netherlands. One of the main drivers of the high positive risk premia on these borders is related to the Climate Change Levy (CCL) exemption in Great Britain, which expired on 31 July 2015. The functioning of this exemption and its impact on the price formation of TRs is explained in a brief case study below. It illustrates how uncoordinated EU energy policies can lead to distortions in price formation and potentially offset some of the benefits of market integration. The distortion ended when the CCL exemption expired.

58 A slight reduction in the risk premia of PTRs on the Northern Italian borders was observed following the introduction of the DA market coupling of Italy with Austria and France. However, it is too early to say how the lack of market coupling had been affecting the risk premia of TRs on the Italian borders with Austria and France.

59 On the 30th October 2015, the EU MSs gave a favourable opinion on the Draft Regulation establishing the FCA Guideline, available at http://ec.europa.eu/transparency/regcomitology/index.cfm?do=search.documentdetail&9uWAKrl21/iPIe4EcYLj5fucOMAYNt7Vijr5subIRSdDh9UefhSUrwYoX9GGF1ia. This Draft Regulation was submitted to the European Parliament and Council for scrutiny, which was not yet finished at the time of the publication of this report.

60 This reduction is in addition to the reduction in the cash flows that the product can deliver already reflected in the calculations in Table 5.

Case study 2: The Climate Change Levy exemption in Great Britain and its impact on the price of TRs on the British borders with France and the Netherlands

In 2001, the British Government introduced the CCL on energy delivered to the business sector in the United Kingdom, in order to stimulate energy efficiency and reduce greenhouse gas emissions.

For electricity consumption, a CCL exemption was approved if the electricity supplier documented that the electricity was produced from RES. Imported electricity was also eligible for CCL exemption if it was accepted as “renewable” and its use for consumption within the United Kingdom was accredited.

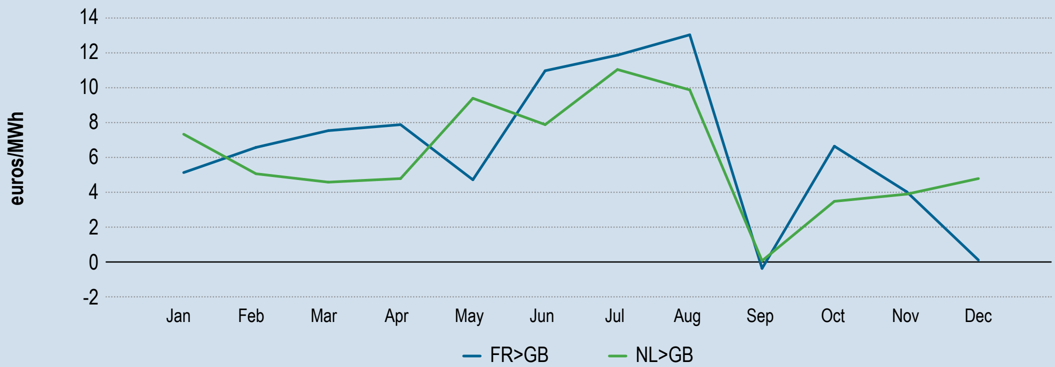
Foreign electricity plants were accredited by the national regulators, Ofgem or NIAUR[61], and eligible production was documented with the issue of Levy Exemption Certificates (LECs). LECs are valuable because businesses can buy them rather than pay the CCL. For production in Continental Europe and the Nordic region, consumption in the United Kingdom was documented by PTRs through interconnectors from the Netherlands and France to United Kingdom, and a guarantee from the producer that the electricity was not sold for consumption in any other country than the United Kingdom.

Ofgem accredited nearly 20,000 MW of foreign capacity for LECs, while the capacity (and PTRs) of the two interconnectors – i.e. France-United Kingdom and the Netherlands-United Kingdom – is not more than 3,000 MW. Therefore, PTRs became a bottleneck and resulted in a considerable price difference between LECs delivered in the Nordic/Continental market compared to LECs delivered in the British market. The prices of deliveries in the Nordic/Continental market area could be below 0.5 euros/MWh, while prices in the United Kingdom could be well above 5 euros/MWh (reaching 7.65 euros/MWh in 2015).

As a result, traders that were exporting to the United Kingdom internalised this price difference in their bids to buy TRs from France or the Netherlands, which increased the price of TRs in an amount equivalent to the price difference. This distortion in the formation of TRs might have affected the efficient integration of forward markets for the period during which the LECs were issued. For example, a Dutch or French generator who was able to produce at a cost equal (or few euros below) the forward market price in the Netherlands or France (often below the forward market price in the United Kingdom) would not have seen a profit in exporting to United Kingdom, due to the increased costs of TRs reflecting environmental policies in United Kingdom. In terms of market integration, this is clearly inefficient.

Following a decision of the British authorities in July 2015, renewable electricity generated on or after 1 August 2015 is no longer eligible for CCL exemption, so the distorting effect on the prices of TRs stopped immediately[62]. This is clearly illustrated in Figure (i), which shows the risk premia of monthly TRs on the British borders with France and the Netherlands before and after the period of exemptions.

Figure (i): Risk premia of monthly TRs from the Netherlands and France to Great Britain – 2015 (euros/MWh)



Source: Common FUI Portal and Platts (2016) and ACER calculations.

61 Northern Ireland Authority for Utility Regulation.

62 However further monitoring during a longer period of time is needed to confirm this development.

6.2.2 Risk premia for Electricity Price Area Differentials

95 Table 6 shows the risk premium for EPADs for the different bidding zones where they are offered. It shows that, in most cases, on average[63], risk premia are positive. This suggests that, in general, there is a shortage in the supply of EPADs and that the buyers of these products (e.g. suppliers) struggle more often than sellers (e.g. generators) to cover their needs for hedging in the corresponding markets.

Table 6: Discrepancies between the price of EPADs (monthly products) and the DA price spreads between the system price and the relevant price in the bidding zone – 2011–2015 (euros/MWh)

Bidding zone	Sample size	Average EPAD price	Average difference System-BZ price	Average risk premium	Average risk premium 2015
SE-4	50	4.2	2.4	1.8	1.0
DK_E	60	5.1	3.3	1.8	1.5
SE-3	50	2.5	1.4	1.1	1.1
FI	60	6.2	5.2	1.0	-0.1
DK_W	60	2.6	2.0	0.6	0.7
SE-2	49	1.1	0.9	0.1	1.3
NO-1	29	-1.0	-1.0	0.1	-1.6
SE-1	47	1.0	1.0	0.0	1.3
NO-4	15	1.0	1.3	-0.3	1.2

Source: Nordpool, Nasdaq (2016) and ACER calculations.

Note: The sample size is the number of monthly products with some volumes traded on the PX in the period 2011-2015. The average EPAD price (column 3) is the arithmetic average of the prices of all monthly EPADs included in the sample. The price of monthly EPADs are calculated as the volume-weighted average of all closing prices during the trading period. The average difference between the system price and the bidding zone price (column 4) is the arithmetic average of the difference between the DA system price and the bidding zone price during the delivery period of the monthly EPADs included in the sample. The average risk premium (column 5) is the arithmetic average of the risk premia of all monthly products included in the sample and is equal to the difference between the values in column 3 (average EPAD price) and 4 (average difference System-BZ price).

96 As presented in last year's MMR, three of the main factors affecting the absolute value[64] of risk premia of EPADs are: (i) EPAD buyers' (demand) and sellers' (supply) hedging needs; (ii) the level of market liquidity; and (iii) market concentration. The impact of these three elements on the risk premia of EPADs is assessed below.

97 The need for hedging products can be prompted by many factors[65], one of which is the price volatility of the system price and a given bidding zone price. A good approximation of price volatility is the degree of correlation between these prices. The interpretation of the correlation is as follows: a high correlation would indicate a low volatility of price differentials and vice-versa. Therefore, when the correlation is low, the needs for hedging can be expected to be high and vice versa. This may be explained by the fact that, when prices are highly correlated, some market participants may consider that the system price forward product is sufficient to meet their hedging needs and may prefer not to buy or sell EPADs in addition to the forward product.

98 The level of liquidity and market concentration in the supply of EPADs can be estimated by calculating, respectively, the average bid-ask spread and the market share of the five largest sellers (CR5[66]) in the supply of EPADs, based on contracts traded on the power exchange. An important caveat underlying the use of these two indicators is that they are based only on volumes traded in the power exchange, which comprises around 20% of the overall volumes of EPADs (because the data do not include over-the-counter trades). These indicators are an approximation of the 'true' liquidity and competition in the overall market of EPADs. However, these are valuable for comparing the degree of competition and liquidity in different bidding zones. Table 7

63 It should be noted that the values shown in Table 2 are average values, so the table does not capture fluctuations over time. For instance, there are several cases of negative risk premia, although in general they are considerably less frequent than the periods of positive risk premia.

64 The sign of the premia depends, among other factors, on the relative level of demand and supply.

65 Price differentials volatility is also influenced by many other factors, including hydrologic forecasts and the expected availability of cross-border transmission capacities.

66 CR3 is more frequently used. However, Nasdaq provided only CR5 indicators.

shows the risk premia (as presented in Table 6) for each Nordic bidding zone, the price correlation levels (as defined above), average bid-ask spreads and CR5 indicators based on EPAD trades on the exchange.

Table 7: Average risk premia, price correlation between system and zonal price, average bid-ask spread, and supply concentration levels of traded EPADs on the power exchange – 2011–2015 (euros/MWh and %)

Bidding zone	Average risk premium (euro/MWh)	Price correlation (between system and bidding zone prices, %)	Average bid-ask spread (euros/MWh)	Average CR5 (%)-supply side
DK_E	1.8	74%	1.1	84
SE-4	1.8	88%	0.8	60
SE-3	1.1	93%	0.6	73
FI	1.0	69%	0.8	68
DK_W	0.6	39%	1.0	77
SE-2	0.1	94%	0.8	64
SE-1	0.0	94%	0.9	73
NO-1	0.1	95%	2.6	86
NO-4	-0.3	95%	2.2	94

Source: Nordpool, Nasdaq (2016) and ACER calculations.

Note: Risk premia and bid-ask spread indicators refer to monthly EPAD contracts traded in the period 2011-2015. The price correlation refers to the period from November 2011, following the split of Sweden into four bidding zones, and December 2015. CR5 is the market share (based on sales) of the five biggest suppliers of EPADs for yearly to weekly products in the period 2013-2015 (market concentration indicators for 2011 and 2012 were not available).

99 The following inferences can be drawn from Table 7. First, the high correlation between the system and bidding zone prices in the areas of Norway 1, Norway 4, Sweden 1 and Sweden 2 seems to explain the relatively low absolute value of risk premia in these areas. As explained above, if the correlation between the system and bidding zone price is high, a relevant share of suppliers and large consumers may prefer not to buy EPAD contracts in addition to the forward product, which provides a hedge against fluctuations of the system price[67]. Second, in Norway, approximately 60%[68] of end-consumer contracts are linked to the DA price in the relevant bidding zone, which reduces a supplier's needs for hedging and, consequently, further reduces the risk premia.

100 The relatively high average risk premia in Eastern Denmark appears to be due to a combination of the three factors presented in Table 7, including a lower than average price correlation (i.e. higher volatility of price differentials), a relatively high bid-ask spread (indicating relatively low liquidity) and a moderately high market concentration. This is probably related to the large share of wind generation in Eastern Denmark, which, on the one hand, reduces the number of generators that can 'safely' sell EPADs, and on the other hand, increases price volatility and the hedging needs of retailers and large consumers. In Finland and West Denmark, the relatively low market concentration seems to explain the moderate risk premia in these two bidding zones.

101 In Sweden 4 and, to a lesser extent, in Sweden 3, the results are counter-intuitive, because these two areas show a relatively high risk premium in spite of relatively high liquidity, low market concentration and a relatively high correlation. In Sweden 4, the results can be partly explained by the reduced number of large generation plants in frequent use[69], which limits the possibilities of engaging in asset-backed EPAD trading, resulting in a relatively reduced volume of (sell) offers from generators compared to the volume of (buy) offers from suppliers and large consumers in the market for EPADs.

67 Furthermore, when there is a probability of low rather than high prices (for instance, because of abundant precipitation) in certain bidding zones, e.g. in Norwegian bidding zones, this could lead to higher demand for hedging (against low prices) among producers than the demand for EPADs among suppliers. This may partly explain the relatively low risk premia in Norway 1 and Norway 4.

68 According to information provided by the Norwegian NRA (NVE).

69 The relatively low concentration in Sweden 4 can be attributed to a changed usage of thermal generation plants in the area in recent years. As electricity prices have been low compared to fuel prices, thermal plants that have previously been used to hedge EPAD issuance, have not been used as often in the last few years. This would have reduced some market players' dominance in the EPAD-market of Sweden 4. That could also explain why the CR5 number is "better" than expected and lower than suggested in the 2014 MMR.

102 The results presented above point to potential liquidity and competition issues in the market of EPADs in some bidding zones (e.g. in East Denmark, where relatively high levels of risk premia are observed). In other bidding zones, e.g. in Sweden 4, the liquidity and competition levels, which are higher than the average values for all bidding zones, do not explain the presence of relatively high risk premia. The development of the EPADs market should be studied and evaluated further[70]. The forthcoming FCA Guideline will provide a framework for assessing whether financial markets are considered as sufficiently efficient to offer the parties involved the opportunities to hedge bidding zone prices that they need. This is particularly important in order to decide whether additional measures to support liquidity may be necessary. For example, if liquidity remains weak, different solutions (e.g. by assigning additional roles to TSOs, such as acting as or supporting market makers, auctioning EPADs or EPADs combos[71]) may need to be explored.

7 Day-ahead markets

Chapter summary

The day-ahead market is considered the most developed cross-border trading timeframe[72]. In line with last year's MMR, this Chapter assesses the level of price convergence in day-ahead markets at regional level and the key factors affecting price convergence (Section 7.1), the progress of implementing market coupling (Section 7.2) and the gross welfare benefits of the incremental expansion of interconnectors (Section 7.3).

The analysis shows that the recent implementation of market coupling on the French-Spanish border increased the level of price convergence recorded in the South-Western Europe region in 2015. Moreover, the go-live of the Flow Based Market Coupling project in May 2015 contributed to further price convergence in the Central-West Europe region. However, this increase was lower than expected, partly due to the effect of an increased amount of unscheduled cross-border flows limiting the tradable cross-border capacity within the region. Finally, the Chapter presents the development in the overall level of efficiency in the use of the interconnectors, which slightly decreased in 2015. This was caused by a reduced efficiency in the utilisation of cross-border capacity on the nine borders that remained with explicit auctions by the end of 2015.

7.1 Day-ahead price convergence

103 This Chapter focuses on the price convergence of DA markets. The convergence of wholesale electricity prices can be regarded as an indicator of market integration, although in the short term, price convergence is frequently affected by factors other than market integration[73]. In line with last year's MMR, this section focuses the level of price convergence at the regional level.

104 Figure 19 provides an overview of the development of hourly price convergence within European market regions from 2008 to 2015. It shows that, in 2015, the most significant increases in price convergence were recorded in the Nordic and SWE regions (29% and 14% in 2015 compared to 17% and 8% in 2014, respectively).

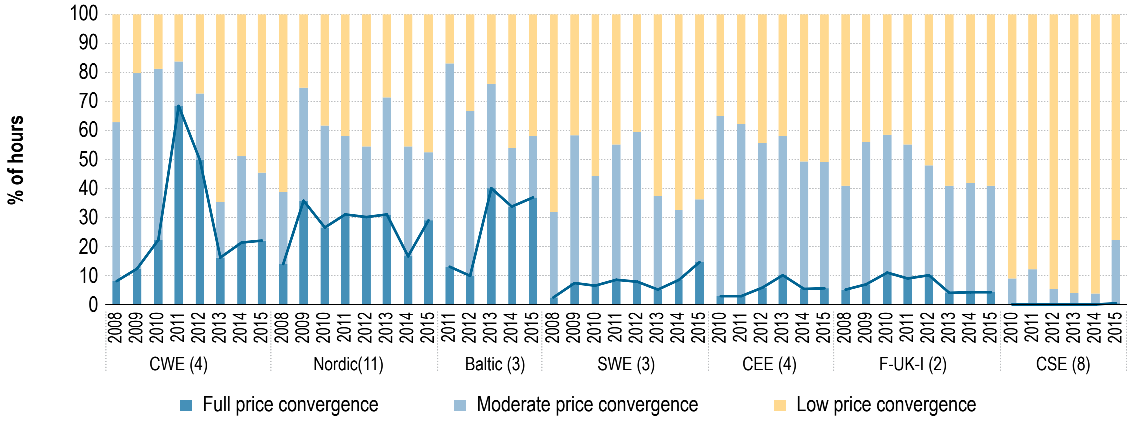
70 In this context, the Nordic Energy Regulators are exploring measures that could be necessary to support the functioning of the Nordic financial electricity market, see more details at http://www.nordicenergyregulators.org/2015/12/nordreg-launches-report-on-measures-to-support-the-functioning-of-the-nordic-financial-electricity-market/.

71 An EPAD Combo is a combination of two EPAD contracts, a sell for one area and a buy for another.

72 Compared to the long-term and shorter than DA timeframes (i.e. intraday and balancing timeframes).

73 This includes, among other factors, the relative evolution of gas and coal prices, the availability of natural resources or changes in national policies, e.g. regarding subsidies to investments in RES.

Figure 19: DA price convergence in Europe by region (ranked) – 2008–2015 (% of hours)



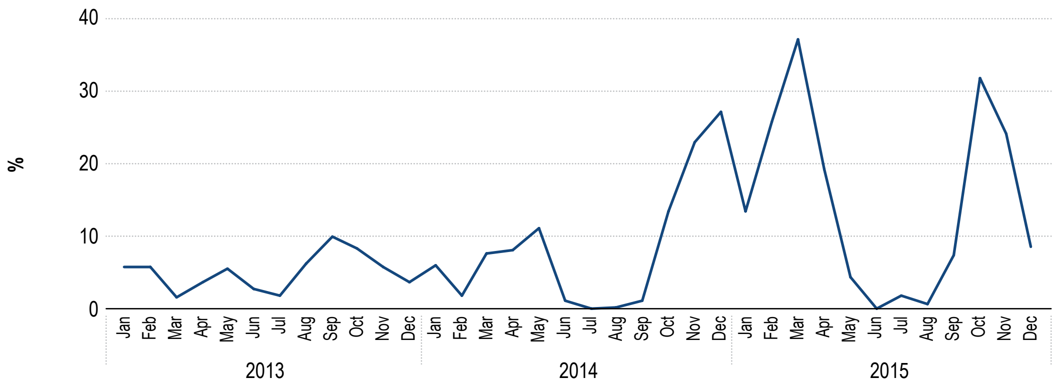
Source: EMOS, Platts, power exchanges and ACER calculations.

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

105 In the Nordic region, most of the increase in price convergence was recorded during night hours, when Finnish prices (usually the highest in the Nordic region) were as low as in neighbouring zones. This was caused by greater wind and hydro generation in Finland in combination with a partial recovery (annual increase of 15%) in imports to Finland from Russia in 2015 compared to 2014.

106 In the SWE region, the increase in price convergence in 2015 was related to the implementation of market coupling on the French-Spanish border. Figure 20 shows the sudden increase in price convergence in the SWE region, two months after the launch of market coupling on the French-Spanish border in May 2014.

Figure 20: Evolution of DA price convergence in the SWE region – 2013–2015 (% of hours)

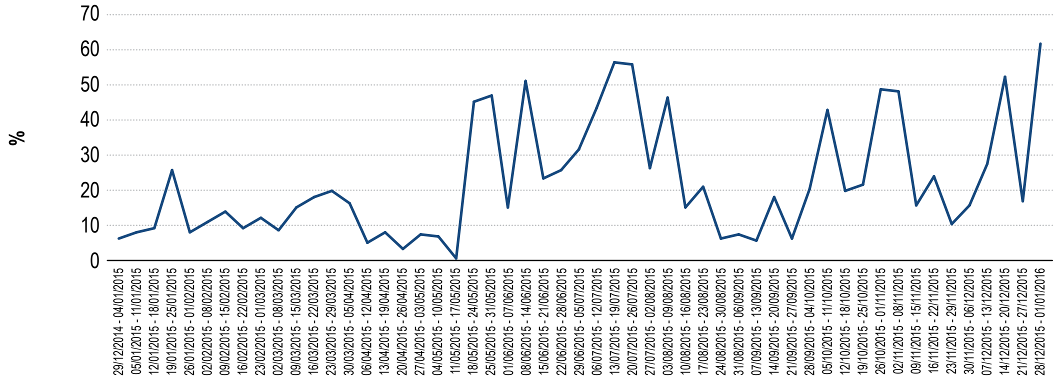


Source: EMOS, Platts and ACER calculations (2016).

107 The CWE region experienced a slight increase in price convergence in 2015 (on average, 1% more than in 2014). The increase was lower than expected[74] following the go-live of FBMC, due to the combined effect of an increased amount of UFs limiting the tradable cross-border capacity in CWE (see Section 5.1 on UFs) and prolonged outages of nuclear power plants in Belgium. However, Figure 21 shows a noticeable price convergence increase following the implementation of FBMC in CWE in May 2015.

74 According to the ACER 2015 MMR, where the results of a "parallel" run of the FBMC algorithm were shown, an increase of around 20% in price convergence could be expected.

Figure 21: Weekly DA price convergence in the CWE region – 2015 (% of hours)



Source: EMOS, Platts and ACER calculations (2016).

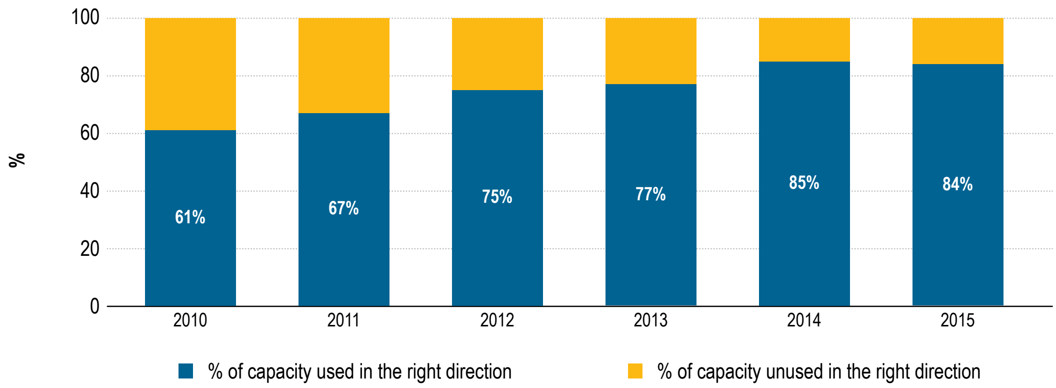
108 In the remaining regions, no significant changes in price convergence were observed in 2015.

7.2 Progress in day-ahead market coupling

109 The Electricity Target Model (ETM) for the DA market envisages a single European price coupling applied throughout the EU and Norway, which eliminates the remaining "wrong-way flows"[75]. This has been the case for the (Figure 49 in the Annex) Spanish-French, Austrian-Italian and French-Italian borders, following the extension of market coupling to these borders[76]. The same applies to the Hungarian-Romanian border following the extension of market coupling to Romania in late 2014.

110 Figure 22 shows that, overall, the efficient use of European electricity interconnections increased from around 60% in 2010 to 84% in 2015, following the implementation of market coupling at several borders since 2010. In 2015, a reduction of less than 1% in the efficient use of the interconnectors was recorded, in spite of the extension of market coupling to the borders listed above. The improved efficiency on these borders was offset by decreased efficiency on non-coupled borders (e.g. on the border between France and Switzerland), probably due to decreased accuracy in the trader's forecast of DA price differentials in 2015. This emphasises the importance of implementing market coupling on all the EU borders that still had explicit auctions at the end of 2015 and on all the Swiss borders.

Figure 22: Percentage of available capacity (NTC) used in the "right direction" in the presence of a significant price differential in all EU electricity interconnectors – 2010 (4Q)–2015 (%)



Source: ENTSO-E, NRAs, Vulcanus (2016) and ACER calculations.

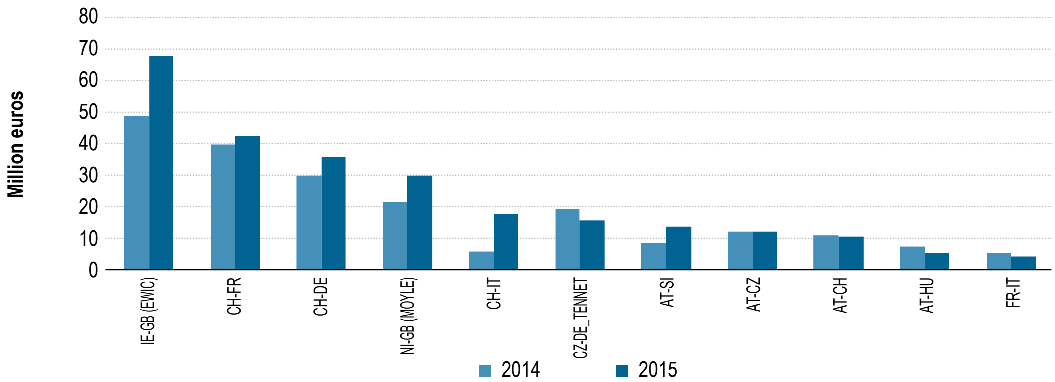
75 A 'wrong-way flow' hour is considered as such when the final net nomination on a given border takes place from the higher to the lower price zone, with a price difference of at least one euro/MWh.

76 In the case of the Spanish-French border, no wrong way-flows were reported for 2015, because the extension took place in May 2014. In the case of Italian borders, the extension occurred in February 2015, and a small share of 'wrong-way flows' were still recorded in 2015.

111 Due to the implementation of market coupling on 31 out of 40 borders, the EU has been able to reap significant efficiency gains (and hence improved social welfare) for the benefit of EU electricity consumers. The potential gain from the extension of market coupling to all European borders was estimated at more than one billion euros per year in the 2013 MMR[77]. Figure 23 shows that, from that amount, more than 250 million euros per year are still to be obtained by the implementation of market coupling on all remaining borders.

112 In Figure 23, European borders are ranked by the "loss in social welfare" due to the absence of market coupling in 2014 and 2015. It indicates that the borders between Great Britain and Ireland and the French and German borders with Switzerland continued to have the highest losses in social welfare among non-coupled borders[78].

Figure 23: Estimated "loss in social welfare" due to the absence of market coupling, per border – 2014–2015 (million euros)



Source: ENTSO-E, data provided by NRAs through the EW template, Vulcanus (2015) and ACER calculations.

Notes: Only non-coupled borders are shown. The borders within the 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 CEE borders for this calculation. Figure 49 in the Annex shows that cross-border capacity was underutilised in 2015 on those borders (CZ-DE, DE-PL, PL-SK), as they were affected by "wrong-way flows". Furthermore, IE-GB (EWIC) refers to the East-West Interconnector which links the electricity transmission grids of Ireland and Great Britain. NI-GB (MOYLE) refers to the Moyle Interconnector, which links the electricity grids of Northern Ireland and Great Britain.

113 All in all, the values of losses due to inefficient DA allocation methods shown above illustrate the urgent need to finalise the implementation of market coupling, exacerbated by the fact that the CACM Regulation, aimed at establishing a single DA market coupling, entered into force on 14 August 2015. In this regard, two important steps towards an integrated European electricity market were completed in 2015. The first, mentioned above, took place on 24 February, when the Italian-Austrian, Italian-French and Italian-Slovenian DA markets were coupled with the Multi-Regional Coupling (MRC), which now covers 19 countries from Finland to Portugal. The second took place on 21 May, when FBMC was launched in the CWE region. The benefits of FBMC in terms of increased tradable cross-border capacity and price convergence are illustrated in Sections 3.1[79] and 7.1, respectively.

77 See http://www.europarl.europa.eu/meetdocs/2014_2019/documents/itre/dv/acer_market_monitoring_report_2014_/acer_market_monitoring_report_2014_en.pdf.

78 The 'losses' on the Italian-French border in 2015 refer to the period before market coupling was extended to that border.

79 This section shows that the amount of tradable capacity in the CWE region decreased due to the increase in the amount of UFs in 2015, although FBMC is expected to increase the amount of capacity available for cross-border trade.

7.3 Gross welfare benefit of better use of the existing network

114 Market integration is expected to deliver several benefits. One of them is enhanced economic efficiency, allowing the lowest cost producer to serve demand in neighbouring areas. This section shows the additional benefit of an incremental increase in interconnector capacity on a bidding zone border, using the "gross welfare benefits"[80] indicator.

115 For the purpose of this Chapter, several European Power Exchanges[81] were asked to perform a simulation in order to estimate these gross welfare benefits for the year 2015. The algorithm used for the simulations originates from the Price Coupling of Regions (PCR) Project (Euphemia), which is used for clearing the single European DA price coupling of power regions.

116 On the basis of a set of assumptions[82], the gross welfare benefits for 2015 were computed for two scenarios:

1. Historical scenario: The gross welfare benefit for 2015 calculated on the basis of detailed historical information such as network constraints, the exchange participants' order books (that is, supply and demand bids) and available cross-border capacity. For the latter, the ATC has been used as a proxy of capacity effectively made available for trade on 24 borders;

2. Test scenario: The same as in the Historical scenario, with the ATC values for each border inflated by 100 MW[83]. As explained above, the assumption is that all other elements (market bids, network constraints, market rules, etc.) remain unaltered.

117 Figure 24 shows the so-called "Incremental Gain" for 2015, which is the difference between the Historical scenario and the Test scenario and shows which borders would benefit the most from making extra capacity available. For comparability the figure also presents the results from the previous four MMR editions, i.e. 2011 to 2014 in Panel A and 2013 and 2014 in Panel B. Note that extra capacity in this context is not necessarily associated with more investments, but could instead be related to the more efficient use of existing cross-zonal capacities, for instance by improving the capacity calculations performed by TSOs (see Chapter 4).

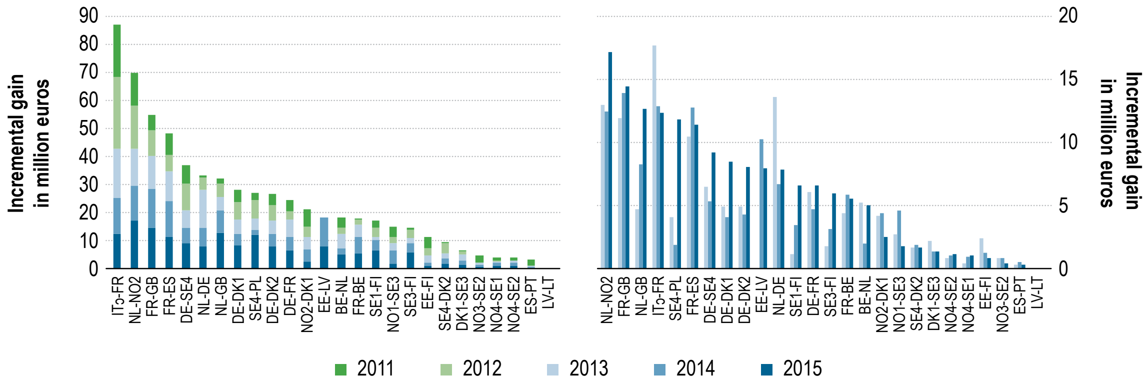
80 Gross welfare benefit includes, first, the "consumers" and "producers" surplus gained by consumers and producers who participate in power exchanges (welfare is measured as the difference between the prices bid into the market and the obtained matched prices multiplied by the quantity) and second, 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.

81 APX, BELPEX, EPEX SPOT, Nord Pool Spot, GME, OMIE and OTE.

82 Due to the assumptions, several caveats need to be made, which are the same as mentioned in the MMR 2014, paragraph 503. Furthermore, due to time constraints, the simulations have been obtained with a criterion stopping the algorithm when the first valid solution was found, whereas in reality this criterion would be determined by a time limit. For some individual sessions, welfare counter-intuitively decreased under the incremental scenario, which can be explained by differences in block or minimum income conditions and is aggravated when stopping after the first solution. Since, theoretically, welfare should not decrease with additional capacity, welfare was estimated to increase to 0 euro for these sessions. In addition, as in the CWE, FBCM is applied since 2015 a "virtual" ATC exchange was assumed to obtain the results.

83 For the reason for setting the increment at 100 MW, see 2014 MMR, footnote 299.

Figure 24: Simulation results: gross welfare benefits from incremental gain per border – 2011–2015 (million euros)



Source: PCR Project (2015).

Note: ɔ indicates that the zone is a GME zone; DK, NO and SE with a number refers to the different bidding zones in Denmark, Norway and Sweden.

118 Panel A in Figure 24 shows the cumulative social welfare gain by borders for the period from 2011 to 2015. It indicates that additional capacity between Italy and France would have rendered the highest social welfare gain over this period. During the same period, an increase in the available cross-border capacities on other French borders (i.e. France-Great Britain and France-Spain) and on the interconnector between the Netherlands and Norway could have also delivered high social welfare gains. Panel B shows further that social welfare from an increase in available capacity between Sweden and Poland could have delivered benefits in 2015 six times higher than in 2014 (11.9 million euros, compared to 1.9 million euros). In this same period, the benefits which could have been delivered by greater cross-border capacity in the interconnector between the Netherlands and Norway, and between the Netherlands and Great Britain also increased by a factor of 1.5, from 12.5 to 17.2 million euros and from 8.3 to 12.7 million euros, respectively.

8 Intraday markets

Chapter summary

The importance of intraday markets for electricity in Europe is increasing together with the growing need for short-term adjustments due to the greater penetration of intermittent generation from RES into the electricity systems.

This Chapter reports first on the liquidity level of intraday markets for several MSs (Section 8.1), on intraday prices and the incentives to participate in the intraday market (Section 8.2), and on the use of cross-border transmission capacity during the intraday timeframe (Section 8.3).

The analysis shows that in 2015, intraday liquidity increased significantly in Germany and its neighbouring markets due to the increasing penetration of renewables in Germany and the introduction of some regulatory measures (e.g. reducing the share of renewable electricity generators exempt from balancing responsibility).

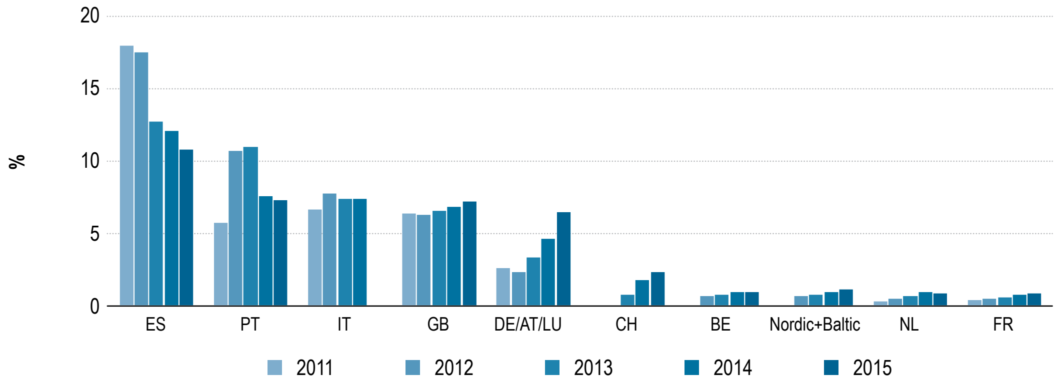
The occurrence of high-price periods in intraday markets (e.g. in Germany and in Spain) is declining, suggesting a situation of overcapacity, the need to enhance the design of balancing markets in order to support more efficient intraday trading and the need to advance urgently with the implementation of the intraday target model.

8.1 Intraday liquidity

119 An efficient EU ID market requires sufficient liquidity, which is currently relatively low in the majority of national markets (including markets where ID traded volumes are below the volumes of activated balancing energy, e.g. in Belgium, where the latter were more than 30% higher than the former in 2015).

120 Figure 25 presents ID traded volumes (in national organised markets) expressed as a percentage of physical consumption across a selection of MSs. Overall, it confirms the upward trend of ID liquidity in the DE/AT/LU market, which increased by 42% in 2015 compared to 2014. This suggests that the regulatory measures introduced in 2014 have contributed to the further increase of ID liquidity in Germany. These measures were aimed at reducing the share of renewable electricity generation exempt from balancing responsibility (around 43 % of installed German renewable capacity by the end of 2015) and to avoid imbalance prices[84] being set below cost incurred. Other factors contributing to ID liquidity were the launch of 15-minute products ID auctions (which complement the continuous trading of those products) in December 2014 and the extension of the trading of 15-minute contracts to the continuous ID market in Austria in October 2015.

Figure 25: ID traded volumes as a percentage of electricity demand in a selection of EU markets – 2011–2015 (%)



Source: Power exchanges and the CEER National Indicators Database (2016).

121 Furthermore, the French and Swiss ID markets recorded increases of respectively 14% and 35% in the same period, probably benefitting from their integration with the DE/AT/LU market through the implicit continuous allocation of ID cross-border capacity.

122 The liquidity of the remaining markets showed very modest increases or did not increase at all. However, increased ID liquidity should not be considered an objective in itself, but only a prerequisite to achieving more efficient balancing of electricity systems. The latter also requires efficient ID price formation.

8.2 Intraday prices and incentives to participate in the ID market

123 In well-functioning markets, ID prices should reflect the value of flexibility[85], in particular ID prices should be very high or very low[86] at times of scarcity[87], i.e. when the reserves available for balancing the system are close to their depletion. With the increasing penetration of renewable electricity generation, an increasing demand for flexible resources, resulting in high-price periods in short-term markets (including ID markets) was envisaged. However, high-price periods are currently not very frequent (see, for example, paragraph (125) for Germany) in European ID markets. The reasons for this reduced frequency are explained below.

124 First, ID prices tend to correlate with DA prices, because ID markets usually open the trading session on the day before delivery as a continuation of DA markets. In this regard, ID prices are affected by the same factors that hinder the reflection of scarcity in DA prices. This includes, among other reasons, installed overcapacity (as a result of declining demand and increasing renewable electricity penetration) and, probably, the impact of different forms of government intervention (see more details in Chapter 1 on key developments over the last decade, e.g. regarding the Spanish market).

84 The German NRA implemented a calculation method for imbalance charges in October 2012, aiming to prevent imbalance charges from falling below the prices in preceding markets. Although this can be considered a positive development, the target (as envisaged in the draft electricity balancing guideline) should be to ensure cost-reflective imbalance charges.

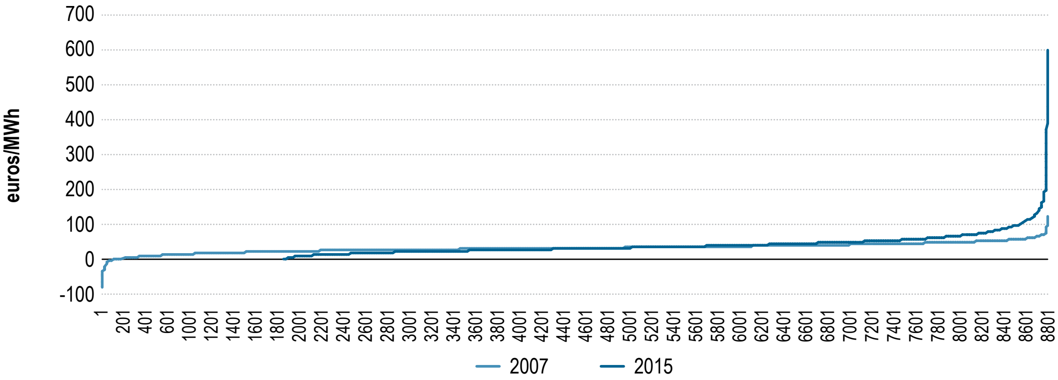
85 Flexibility can be defined as the ability of an electricity system to adapt to rapid and large fluctuations of supply or demand.

86 Very high prices represent the scarcity of upward regulation and very low prices represent the scarcity of downward regulation.

87 Depending on whether there is scarcity of upward or downward reserves, respectively.

125 Figure 26 displays ID price duration curves in Germany for 2007 and 2015. It shows that the number of high-price periods virtually disappeared in the German ID market. For instance, the number of hours with prices exceeding 100 euro/MWh plunged from 262 in 2007 to 1 in 2015. This decrease was more pronounced than the decrease in average ID prices, which fell about 10 euros/MWh, from 41.3 euros/MWh in 2007 to 31.7 euros/MWh 2015. Furthermore, the flattening of the ID price curve resulted in a significant decline in the differential between the highest and lowest price hours in Germany. Figure 50 in the Annex shows a similar evolution of price duration curves in Spain between 2007 and 2015. While in Spain the average ID price was more than 10 euros/MWh higher in 2015 than in 2007, a noticeable decline in the frequency of high-price periods was recorded during the same period. This indicates that this decline was not only caused by the decrease in wholesale market prices.

Figure 26: ID price duration curves in Germany – 2007 and 2015 (euros/MWh)



Source: EPEX and ACER calculations (2016).

126 The flattening of ID prices could be regarded as an efficient development, particularly if it is driven by a shift in demand patterns in response to market price signals. However, given the limited proportion of demand-side participation in Germany[88] (and more generally in Europe), it seems more likely that the excess of generation capacity is the main driver of the decrease in price volatility. This suggests that there is no shortage of flexible resources in Germany and in countries with a similar evolution of ID prices. Moreover, declining differentials between the highest and lowest ID prices reduce incentives for demand participation in the markets.

127 Second, ID prices should correlate well with imbalance prices, because the latter represent the prices that balancing responsible parties pay (or receive) for their residual imbalances. In this respect, the design of balancing markets is essential to enable efficient ID price formation. This implies that all electricity, consumed or produced, should be covered by balancing responsibility, and that generation units from intermittent generation should not receive special treatment for imbalances. Otherwise, renewable electricity generators (or its representatives) will have no incentive to trade in the ID market. Currently, with regard to balancing responsibility, renewable electricity generators are not treated in the same way as conventional generators in at least 15 MSs[89]. Furthermore, imbalance prices should be fully cost-reflective at any time, including times of scarcity. Due to a combination of factors that are elaborated in Chapter 9, this is not always the case in electricity balancing markets.

128 Moreover, another indication of the suboptimal design of imbalance prices is provided by the relatively low degree to which intermittent generation adjust its market position to reflect the more accurate close-to-real-time generation forecasts, (i.e. they do not often refine their schedules in ID markets).

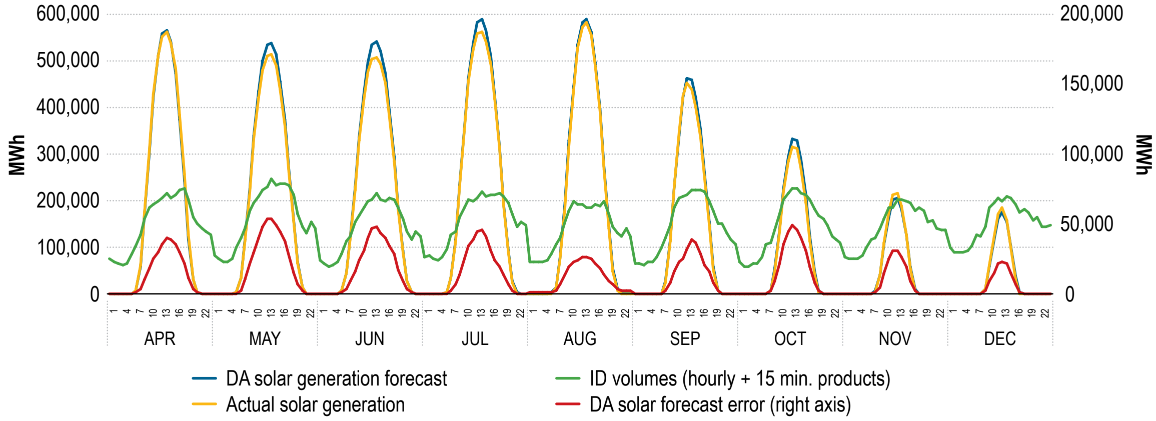
129 In general, a larger amount of ID volumes should be expected during periods of higher DA intermittent forecast errors. These errors can be defined as the difference between the DA forecast of intermittent generation and actual generation. Figure 27 suggests a moderate correlation between ID volumes and DA solar

88 See, for example, http://www.acer.europa.eu/official_documents/acts_of_the_agency/references/dsf_final_report.pdf, pages 87-90.

89 Based on the CEER National Indicators Database, with regard to balancing responsibility, renewable electricity generators (or at least some of them) are not treated in precisely in the same way as any other conventional plants in the following MSs: Austria, Bulgaria, Croatia, Cyprus, Denmark, France, Germany, Greece, Hungary, Ireland, Italy, Lithuania, Malta, Portugal and Slovenia.

electricity generation forecast errors in Germany in the period April-December 2015. The hourly correlation of ID volumes and solar forecast error was 0.55 for the period indicated. However, this correlation was slightly lower than the correlation between ID volumes and actual solar electricity generation (0.56), also shown in Figure 27. These values suggest that a share of renewable generation is systematically traded on ID markets in Germany and that these trades are not necessarily driven by forecast errors.

Figure 27: Average hourly ID volumes (continuous ID market) and average hourly solar electricity generation forecast error in Germany – April–December 2015 (MWh)



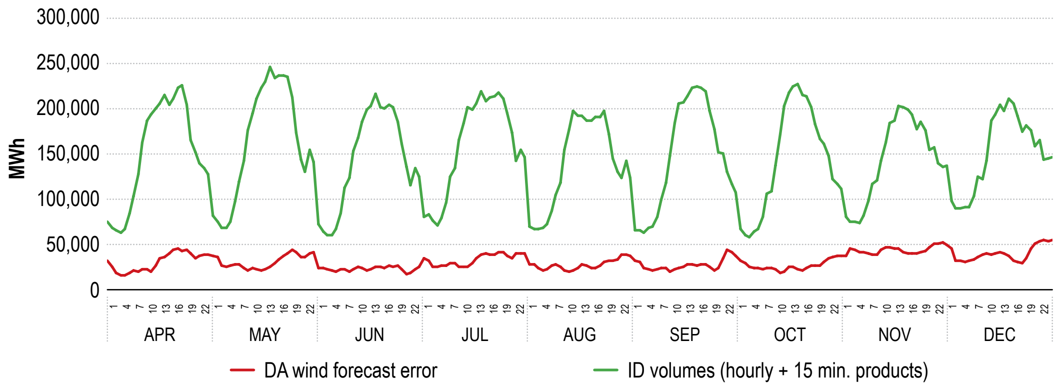
Source: EPEX, ENTSO-E and ACER calculations (2016).

Note: DA solar forecast error is considered to be the difference between the DA solar generation forecast and actual solar generation.

130 The analysis presented above suggests that market participants (e.g. solar electricity generators) do not usually refine their positions beyond a certain level of accuracy and that they do no change this behaviour when imbalance prices are expected to be higher. An exception to this occurred on 20 March 2015 during a solar eclipse, which caused the solar generation forecast in Germany to reach 15 GW just before the eclipse, falling below 7 GW during the eclipse and rising again sharply above 22 GW when the eclipse was over. During these hours, energy traded in the ID timeframe was two to three times higher than the typical values for the same levels of solar generation. This indicates that solar generation plants, or more generally, market participants, found a value in offering their flexibility or in refining their positions in the ID market, as opposed to facing the considerably high imbalance prices that could have been expected during the hours of the eclipse.

131 Lastly, Figure 28 suggests a relatively low correlation (the hourly correlation was 0.22) between ID volumes and wind electricity generation forecast errors in Germany during the same period of 2015.

Figure 28: Average hourly ID volumes (continuous ID market) and average hourly wind electricity generation forecast error in Germany – April–December 2015 (MWh)



Source: EPEX, ENTSO-E and ACER calculations (2016).

Note: DA wind forecast error is considered to be the difference between the DA wind generation forecast and actual wind generation.

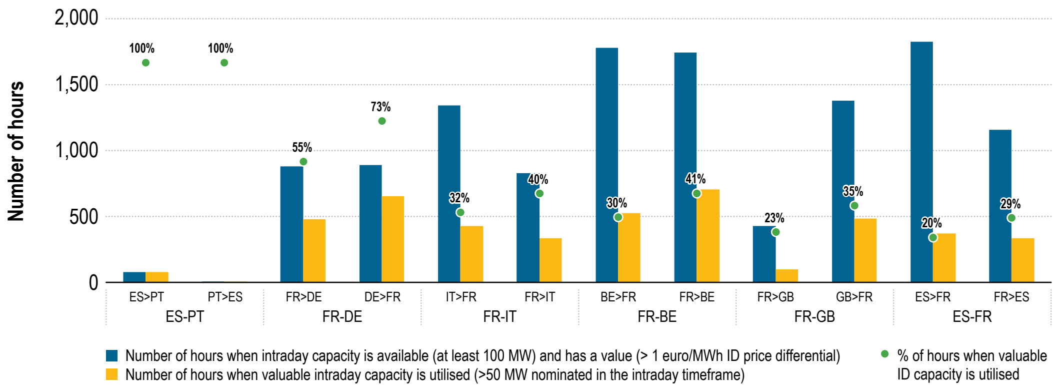
132 Overall, these developments suggest that well-designed balancing markets are essential to ensure the efficient functioning of ID markets. In this respect, it is crucial to ensure balancing responsibility for all market participants (including generation from renewables) and that the balancing markets' design ensures cost-reflective imbalance prices. This would encourage market participants to offer their flexibility or to modify their ID positions in order to support efficient system balancing, particularly during periods of scarcity.

8.3 Intraday use of cross-border capacity

133 Figure 51 in the Annex confirms the increasing trend, reported in previous MMRs, in the utilisation levels of EU cross-border capacity in the ID timeframe. In 2015, the utilisation of cross-border capacity in the ID timeframe was approximately 8% higher than in 2014 and more than double the value recorded in 2010. Additionally, Figure 52 in the Annex shows an upward trend in traded volumes in the ID timeframe for a majority of borders since 2010. In 2015, the most significant progress compared to the year before was recorded on the border between Austria and Germany, following the reduction of the cross-border ID gate closure time to 60 minutes in July 2015 and the introduction of 15-minute contracts in Austria in October of 2015.

134 Figure 29 shows that the level of efficiency in the utilisation of cross-border capacity in the ID timeframe (on average 54% for the borders shown in the figure) was relatively low compared to the level of efficiency in the DA timeframe (84%, as shown in Figure 22) in 2015. Furthermore, Figure 29 confirms that cross-border capacity was used more efficiently in the ID timeframe on borders where the capacity was allocated by using implicit allocation methods in 2015. These methods include either implicit auctions or implicit continuous allocation of cross-border capacity, as opposed to explicit or other allocation methods[90]. This anticipates increasing efficiency in the use of cross-border capacity in the ID timeframe once the target model for the ID timeframe is implemented[91].

Figure 29: Level of utilisation of cross-border capacity in the ID timeframe when it has a value, for a selection of borders – 2015



Source: ENTSO-E, data provided by NRAs through the EW template, Vulcanus (2015) and ACER calculations.

Note: In some markets, ID liquidity (volumes traded) is relatively low. Therefore, an arbitrary threshold of 50 MW was used for this analysis. The percentages indicate the share of the hours when capacity is used in the right direction (>50 MW used) with ID price differentials of at least one euro/MWh and a sufficient availability of cross-border capacity (at least 100 MW).

90 For the borders shown in the figure, the following methods to allocate intraday cross-border capacity are applied. In the Spanish-Portuguese border the allocation of ID cross-border capacity is based on implicit auctions, in the French-German border, implicit continuous allocation of ID cross-border capacity is combined with explicit allocation and in the other borders the ID cross-border capacity is explicitly allocated.

91 The ETM envisages an implicit cross-border capacity allocation mechanism using continuous trading on electricity markets, with reliable pricing of ID transmission capacity reflecting congestion.

135 However, these benefits, from a more efficient allocation of ID cross-border capacity, have not yet materialised fully due to significant delays experienced in the implementation of the ID target model. This can be explained mainly by technical issues and difficulties in reaching consensus among the project parties involved in the so-called Cross-Border ID (XBID) project[92].

9 Balancing markets

Chapter summary

Efficient and well-integrated electricity balancing markets are crucial to ensure that balancing services are provided in the most efficient manner. The growing penetration of intermittent generation reinforces this importance, although efficient intraday markets should partly address this need.

This Chapter reports on the evolution of balancing prices (including balancing energy prices, balancing capacity prices and imbalance prices); it assesses how these prices are affected by different aspects of market design (Section 9.1) and presents the scope for a further exchange of balancing services across EU borders (Section 9.2).

This analysis indicates that the large share of balancing capacity procurement costs in the overall costs of balancing in most of the balancing markets analysed and some inefficiencies of national balancing markets continued to dampen balancing energy prices (and imbalance charges), which may not always accurately reflect the value of flexibility in real time, particularly at times of scarcity. Some countries are considering, or have recently introduced, measures to enable scarcity pricing in the balancing timeframe, e.g. Great Britain, as described in a case study at the end of this Chapter.

Moreover, the analysis confirms the presence of large disparities in balancing energy and balancing capacity prices, suggesting a considerable potential for further cross-border exchanges of balancing services in Europe. Despite an increase in the exchanged amount of balancing capacity observed recently (e.g. following the go-live of the project for a common procurement of Frequency Containment Reserves that involves the German, Austrian, Dutch and Swiss TSOs), the overall cross-border exchange of balancing services continued to be limited in 2015.

9.1 Balancing (capacity and energy) and imbalance prices

136 Figure 53 and Figure 54 in the Annex confirm the persistence of large disparities in balancing energy and balancing capacity prices in Europe in 2015. These disparities are similar to those observed in 2014. This suggests that important efficiency gains are still to be obtained from the exchange of balancing energy and capacity, subject to available cross-border capacity and security limits. The efficient exchange of balancing energy and capacity is the core element of the upcoming Electricity Balancing (EB) Guideline[93], which will provide the legal framework for integrating national balancing markets.

137 Furthermore, the efficient integration of balancing markets requires efficient price formation in national balancing markets. The draft EB Guideline includes three main elements that should enhance the formation of prices in the balancing timeframe: (i) the optimised procurement of balancing capacity, (ii) the removal of elements that prevent balancing energy prices from fluctuating freely and (iii) cost-reflective imbalance prices.

138 An optimised procurement of balancing capacity is a key element in reducing the associated procurement costs; for instance, by enabling the maximum participation of all technologies in the provision of balancing capacity, including renewable energies, storage facilities and demand response. Based on the information collected by NRAs, demand-side participation in the provision of balancing services was non-existent in

92 On 9 June 2015, the PXs involved in the XBID project announced that they had signed a contract with the information technology (IT) service provider This important milestone allowed the project entering in the development phase which is expected to be followed by a one-year testing.

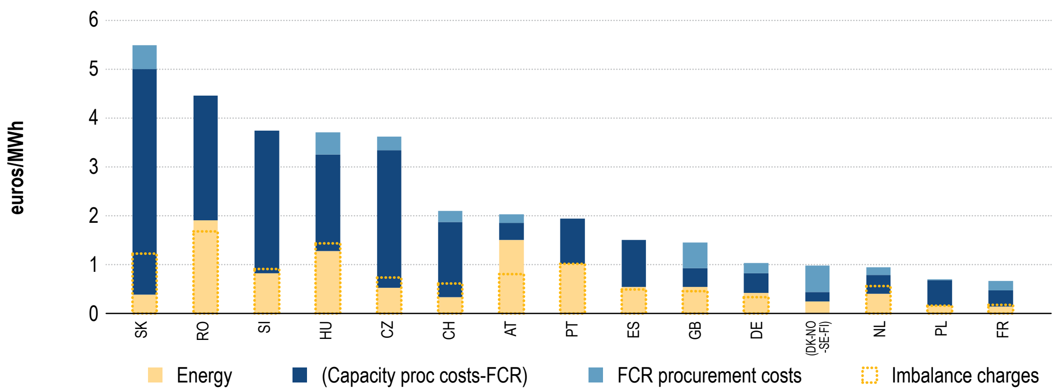
93 A draft of the balancing guideline has been recommended by ACER for adoption. See, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2003-2015.pdf. An updated draft is currently being discussed by the electricity cross-border committee.

nine MSs and non-quantifiable[94] in six MSs in 2015. Only eight MSs – Belgium, Bulgaria, Finland, France, Hungary, Norway, Slovenia and Slovakia – out of the 24 that provided information, reported certain level of demand participation in the provision of balancing services. The levels of demand participation reported for these eight countries were limited, with some exceptions, e.g. in Belgium around 24% of (upward) Frequency Containment Reserves (FCRs) are provided by demand resources and in France around 29% of (upward) mFRRs and RRs, taken together, are provided by demand resources.

139 Figure 30 shows that in most MSs the largest share of balancing costs continued to be the procurement costs of balancing capacity. Compared to 2014, capacity procurement costs decreased in 2015 in Austria, Germany, the Netherlands and Switzerland. This is partly due to the implementation of the coordinated procurement of FCRs (see more details on this initiative in Section 9.2), which lowered the average prices of contracted FCRs in some of these four markets (e.g. in the Netherlands between 2014 and 2015, it decreased by 28%).

140 In Austria, the savings from the coordinated procurement of FCRs were less remarkable (the related prices remained unchanged and the procured volumes decreased slightly). A pronounced decrease (-46%) in the overall procurement costs of balancing capacity was recorded in 2015 compared to 2014. This improvement was driven by a number of regulatory measures that enabled the participation of a wider range of technologies (including aggregated demand response, intermittent and distributed generation) in the provision of balancing services. Because of these measures, the number of market participants in the national balancing market doubled in 2015 compared to 2014, and the prices of various balancing services decreased significantly, e.g. the average prices of balancing capacity from aFRR declined by more than 50%. These developments confirm the benefits of the further integration of balancing markets and the scope for improvement in national balancing markets.

Figure 30: Overall costs of balancing (capacity and energy) and imbalance prices over national electricity demand in a selection of European markets – 2015 (euros/MWh)



Source: Data provided by NRAs through the EW template (2016) and ACER calculations.

Note 1: The overall costs of balancing are calculated as the procurement costs of balancing capacity and the costs for activating balancing energy (based on the activated energy volumes and the unit cost of activating balancing energy from the applicable type of reserve). For the purpose 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. The price of the energy exchanged when imbalance netting is applied is assumed to be the price of activating balancing energy from aFRR in the relevant scheduling area, except in Austria where the actual settlement prices for imbalance netting were made available to the Agency. Imbalance charges applied in the Nordic market are not included in the figure as data was not available for all Nordic countries.

Note 2: Price regulation for balancing energy is applied in certain MSs (e.g.in Czech Republic and Slovakia for the energy activated from all types of reserves and in France for the energy activated from FCRs and aFRRs, representing 40% of the activations in the French system). The procurement costs of reserves reported by the Polish TSO only represent a share of the overall costs of reserves in the Polish electricity system. This is due to the application of central dispatch in Poland which makes it difficult to disentangle the balancing from the redispatching costs.

94 In most of the cases where the participation of demand in balancing services was reported as unquantifiable (Austria, Croatia, Denmark, Great Britain, Switzerland and the Netherlands) it was mentioned that the participation of demand in the provision of balancing services is possible in principle, but information on the load units providing balancing services is not accessible for the TSO, as they are integrated in the portfolios of BSPs that combine generation and load.

141 The relatively high weight of TSOs' balancing procurement payments shown in Figure 30 tends to reduce the real-time value of providing balancing energy, in particular at times of scarcity[95] (i.e. when balancing reserves are close to be depleted). This reduces incentives for generators and demand to respond to immediate balancing needs.

142 The impact of balancing capacity procurement on balancing energy prices is more evident when the balancing energy bids of pre-contracted reserves are predetermined as part of the tender to procure balancing capacity, as these bids do not reflect the real-time value of providing balancing energy. Contracted reserves with predetermined balancing energy prices are – to varying degrees – still used in some MS, such as Austria, Germany and Great Britain.

143 Another important aspect of market design is the pricing method for balancing energy. The draft EB Guideline envisages the application of marginal pricing as opposed to the "pay-as-bid" rule. Marginal pricing is assumed to deliver more efficient short-term signals by enabling the most efficient dispatch and by ensuring that all market participants see the benefits of responding to immediate market needs, and more efficient long-term signals by providing incentives for efficient investments. Currently, several MSs, such as Austria, Belgium, Croatia, Germany, Italy, Slovakia, Slovenia and the United Kingdom still apply "pay-as-bid" rules in energy balancing regimes.

144 All the aspects of market design described above affect the level of imbalance prices applied to BRPs, hence their incentive to trade their imbalances in short-term markets. This incentive can be defined as the difference between imbalance prices and prices in the preceding DA and ID markets. The influence of market design on the magnitude of these incentives is exemplified in Figure 31 and Figure 32, where imbalance, ID and DA prices during periods of negative imbalance[96] are displayed together for Great Britain and the Netherlands with diverging balancing market design features.

Figure 31: DA price duration curve during periods of negative system imbalance, ID and imbalance prices (charged to 'short' BRPs) in Great Britain – 2015 (euros/MWh)

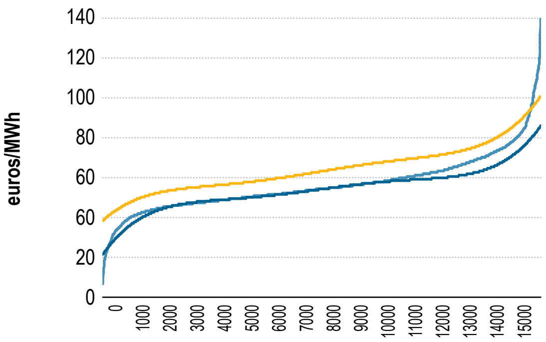
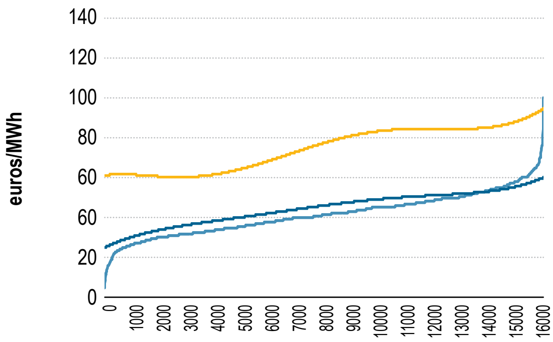


Figure 32: DA price duration curve during periods of negative system imbalance, ID and imbalance prices (charged to 'short' BRPs) in the Netherlands – 2015 (euros/MWh)



DA prices — ID prices — Imbalance prices (short BRPs)

Source: NRAs, EMOS, Platts (2016) and ACER calculations.

Note: The values represent the prices in the different timeframes at the same point during periods of negative system imbalance. The lines for ID and imbalance prices are a polynomial approximation (order 5) of the instantaneous values.

95 If a share of the fixed costs of BSPs are recovered through (balancing) capacity payments, BSPs may refrain from offering balancing energy at a very high price during scarcity periods, as they may fear regulatory investigation for market abuse.

96 A negative system imbalance does not necessarily entail a situation of scarcity, although by selecting periods of imbalance only, it can be assumed that the actual (real-time) reserve margins are lower than expected by market participants.

145 In the British balancing market, before the electricity balancing reform was introduced in November 2015[97], neither balancing energy prices nor imbalance prices were based on the offer of the marginal bid[98]. Moreover, the market design includes pre-contracted balancing capacity products with fixed activation energy prices, an aspect that has not changed following the reform. In the Netherlands, balancing energy and imbalance prices are set by the price of the marginal balancing energy bid, while pre-fixed activation prices are not used. Figure 31 and Figure 32 demonstrate that, on average, incentives (defined as the difference between imbalance and ID prices) for BRPs to refine their positions in the market were around 2.5 times higher in the Netherlands than in Great Britain in 2015, which suggests that marginal pricing and the absence of prefixed balancing energy prices contribute to increasing such incentives.

146 The figures also suggest that prices behave differently at times of scarcity, depending on the market features commented above. When DA prices are 'very high' (right side of Figure 31 and Figure 32), it can be assumed that market participants anticipated a situation of reduced reserve margins (scarcity) and that these margins were even smaller closer to real time (the figures only includes periods of negative imbalance, which implies the activation of some of the available reserves). This should be reflected in balancing energy prices and imbalance prices (displayed in the figures) being above DA prices, reflecting the scarcity situation. While this is illustrated for the Netherlands in Figure 32, Figure 31 suggests that imbalance prices in Great Britain did not always appropriately reflect scarcity in 2015.

147 Some of these inefficiencies can be partly addressed by introducing adequate regulatory measures. The cross-border sharing of balancing reserves and exchange of balancing capacity should in itself contribute to more efficient balancing energy price formation, as cross-border balancing energy competition should reduce the requirements for assurance (reserves) and its potential dampening effect on energy prices. Other provisions included in the draft EB Guideline should also contribute to addressing these issues, such as adequate prequalification rules which do not discriminate among technologies, enable demand participation, optimise the procurement of balancing capacity (e.g. separate procurement of upward and downward balancing capacity and shorter procurement timeframes), avoid pre-determining the balancing energy price as part of the tender to procure balancing capacity, and implement a pricing method based on marginal pricing for balancing energy. The implementation of these measures should be the first priority.

148 However, these measures are not necessarily enough to enable efficient price formation at times of scarcity. This is due to a combination of factors. First, the opportunity costs incurred by consumers in the event of an eventual load reduction, typically referred to as the value of lost load (VOLL), are not usually considered in the clearing of balancing energy prices. Secondly, in some markets, 'high' prices are not allowed, as there are relatively 'low' offers or price caps. Thirdly, BSPs may refrain from offering balancing energy at a very high price during scarcity periods, as they may fear regulatory investigation for market abuse[99].

149 A first measure to ensure that balancing energy prices accurately reflect the scarcity value is to allow BSPs to bid at 'sufficiently' high prices during periods of shortage. Moreover, there are other ways to improve the cost-reflectivity of balancing energy prices, imbalance prices, or both, at times of scarcity. One option is to allocate balancing procurement costs to BRPs in relation to their imbalances through an additive component in imbalance prices (or through a settlement mechanism separate from the imbalance settlement component as suggested in the draft EB Guideline). This measure, advocated in the "Impact Assessment of the European Electricity Balancing Market"[100], would provide BRPs with higher incentives than the 'socialisation' of these costs to network users or to BRPs in proportion to their consumed or produced energy volumes, as currently applied in most of Europe. One of the main challenges of this measure would be to design adequate cost-causality rules that efficiently allocate balancing capacity procurement costs to BRPs.

97 For more details on this reform, see case study 3.

98 In Great Britain, BSPs are remunerated on the basis of pay-as-bid rules. With respect to imbalance prices, they were based on the average 500 MW of the most expensive actions until the reform introduced in November 2015. After this reform, imbalance prices are based on the average 50 MW of the most expensive actions.

99 See footnote 96.

100 See https://ec.europa.eu/energy/sites/ener/files/documents/20130610_eu_balancing_master.pdf.

150 Another option is to introduce an administrative "adder" in the balancing energy price that, based on the concepts of VOLL and loss of load probability (LOLP), aims to simulate the scarcity value at times of reduced reserve margins. This model, known as the "Operational Reserve Demand Curve" (ORDC), is currently applied in Texas (US). In Europe, the Belgian NRA (CREG) recently started to investigate the applicability of this model in its national market as an alternative to CMs.

151 A hybrid of the two models described above was recently introduced in Great Britain as part of its electricity balancing reform. On the one hand, the additive component that is envisaged in Great Britain does not alter balancing energy prices, but is directly included in imbalance prices, as it is the case in the model to allocate balancing capacity procurement costs to BRPs through increased imbalance prices. On the other hand, the British reform is not intended to recover the costs of procuring balancing capacity through imbalance charges, although at times of scarcity imbalance charges can be increased by a certain amount. This amount is calculated by using the concepts of VOLL and LOLP, as envisaged in the ORDC model. The case study below describes the main characteristics of the electricity balancing reform introduced in Great Britain in 2015, including measures to enable scarcity pricing in the balancing timeframe.

Case study 3: Scarcity pricing in the balancing timeframe of the electricity wholesale market in Great Britain

Background to Great Britain imbalance price reforms

Imbalance prices are the key incentive for market participants to balance. Therefore, they have a fundamental impact on energy market trading and investment decisions. On 5 November 2015, the imbalance arrangements in Great Britain underwent large-scale reform as a result of Ofgem's Electricity Balancing Significant Code Review (EBSCR). The EBSCR highlighted several issues with the existing calculation of imbalance prices that resulted in inefficient energy market signals, such as dampened signals for flexibility (i.e. the ability to ramp generation or demand up or down quickly in response to changing market conditions).

A key issue was that imbalance prices did not always appropriately reflect scarcity, due to the following three main factors:

1. They were calculated using an average of the prices of energy balancing actions, rather than the price of the marginal action;

2. The costs incurred by consumers during load reduction were not included;

3. The use of pre-contracted reserve products, mainly Short-Term Operating Reserve (STOR), with fixed activation prices that did not reflect real time system conditions.

The EBSCR aimed to address the first issue by introducing a more[101] marginal imbalance price and the second by including a cost for disconnections and voltage reduction in the imbalance price calculation based on the VOLL to consumers. Reserve Scarcity Pricing (RSP) was introduced primarily to address the third issue.

Rationale for RSP

During times of energy scarcity, uncontracted BSPs may increase their bid prices to represent the value of energy at that time. If these bids are activated by the TSO, then these prices are reflected in the imbalance price. However, this is not the case for pre-contracted products such as STOR. STOR contracts consist of two cash flows for the BSP: an availability payment and an activation payment. The pre-contracted nature of the product and the inability to accurately target availability payments into imbalance prices in periods where STOR is used means that during scarcity, in the absence of RSP, imbalance prices are dampened. This has

101 See footnote 99.

a further impact on incentives to trade and therefore on wholesale market prices and revenues.

As a result, before the introduction of the EBSCR reforms, market participants had insufficient incentives to provide flexible capacity (such as flexible generation, demand response services and storage) to meet demand. It was also more likely that interconnectors would export at times of system stress (or import less than under more efficient arrangements). As the share of non-programmable RES generation increases, flexibility will only become more important to energy market efficiency and security of supply.

Design of the RSP function in Great Britain

The RSP replaces the balancing energy activation price of pre-contracted STOR (only within the imbalance calculation) with a “replacement price” based on the LOLP and the VOLL. The replacement price allows the price of the reserve product used in the imbalance calculation to better reflect the value of the service that the product is providing at any given time, based on the system margin.

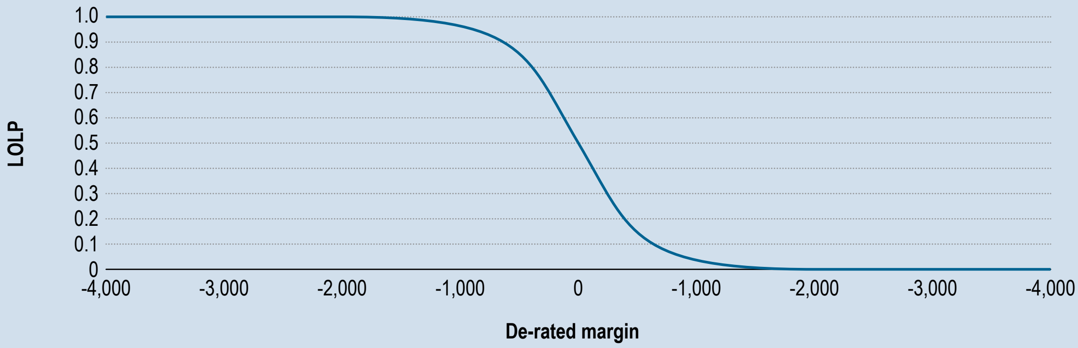
The RSP will kick in only when the replacement price (based on the LOLP and VOLL) is greater than the activation price in the STOR contract. This allows the price in the merit order of actions to still be included until that price insufficiently reflects the scarcity on the system.

A static LOLP function was generated by determining a relationship between historical values of LOLP and de-rated margin. This relationship is represented by using a normal cumulative density function to fit a smooth curve to the historical data.

The static function is defined as:

LOLP = 1 – Normal cumulative density function ($DRMj$, μ, $\sigma 2$)
Where:
DRM = de-rated margin
$\mu = 0$; and
$\sigma 2 = 700$MW

Figure (i): LOLP function in Great Britain



Source: Ofgem (2015).

This LOLP function will be updated in 2018 to become dynamic, allowing it to capture more accurate assumptions about wind generation and demand forecasts.

Impact of RSP BSPs (i.e. on balancing energy prices and capacity procurement prices) and BRPs (i.e. on imbalance prices)

The RSP applies only to imbalance prices and does not directly apply to balancing energy prices (which will continue to be pay-as-bid) or to balancing capacity prices, i.e. does not directly affect the revenue received by BSPs. This provides the Great Britain TSO with flexibility in the way that it procures balancing services. However, the RSP should indirectly affect the revenues received by flexible capacity by driving demand for these products in the energy market up. For example, it is likely that higher imbalance prices incentivise BRPs to trade their imbalances in DA or ID markets more often, which would increase the value of flexibility through respectively higher DA or ID prices at times of scarcity.

In Great Britain, imbalance prices are not designed to recover revenue for the TSO, but to redistribute balancing costs amongst market participants. The impact of RSP is that any participant who is out of balance will pay or receive more than was previously the case. Therefore, a “good balancer”, who supports the system’s balance, would receive larger payments and would be incentivised to balance “better”.

The costs of reserve products paid by the TSO are passed on to market participants through tariffs based on market share (i.e. metered energy volume) in each settlement period. This is a completely separate cash flow, ensuring that the cost of reserve products is always met. However, RSP has the potential to create a surplus of TSO’s revenues at times of scarcity, which could indirectly reduce the amount of TSO’s balancing capacity procurement costs that are socialised through tariffs.

Interactions between RSP and Great Britain’s CM

The CM in Great Britain is intended to address capacity adequacy by providing capacity providers with a secure revenue stream for their investment and to increase generation reliability to a LOLE standard of 3 hours per year. Whilst the CM should, in general, reduce the number of hours with high prices, given the reliability standard, a few hours per year remain (at least, in theory, 3 hours) during which high prices can materialise. In this respect, Ofgem’s imbalance reforms complement Great Britain’s CM by providing improved signals for the value of flexibility, influencing the type of capacity coming forward.

9.2 Cross-border exchange of balancing services

152 An integrated cross-border balancing market is intended to maximise the efficiency of balancing by using the most efficient balancing resources, while safeguarding operational security.

153 Figure 33 and Figure 34 show, respectively, the share of activated balancing energy and of balancing capacity (FCR) procured abroad compared to system needs in 2015. Although there was some progress observed in the exchange of balancing services in 2015 compared to 2014, the figures illustrate that, the exchange of balancing services (excluding imbalance netting) across EU borders in 2015 continued to be limited. Two of the main exceptions are France, where almost 15% of the system requirements for upward balancing energy were fulfilled abroad (see Figure 33) and Finland where more than 50% of the balancing capacity (upward, FCR) was contracted abroad (see Figure 34) in 2015.

154 For example, the cross-border exchange of balancing capacity (FCR) increased following the go-live of the project for the common procurement of FCR that involves the German, Austrian, Dutch and Swiss TSOs in April 2015. On the one hand, this project allows those TSOs that are involved to reduce their balancing capacity procurement costs by importing FCRs from low-price neighbouring control areas and, on the other hand, BSPs benefit from access to an enlarged market for FCR without new prequalification procedures or contracts. Compared to 2014, in 2015 these four countries recorded a reduction of approximately 14% in the overall balancing capacity (FCR) procurement costs.

Figure 33: EU balancing energy activated abroad as a percentage of the amount of total balancing energy activated (upward) in national balancing markets – 2015 (%)

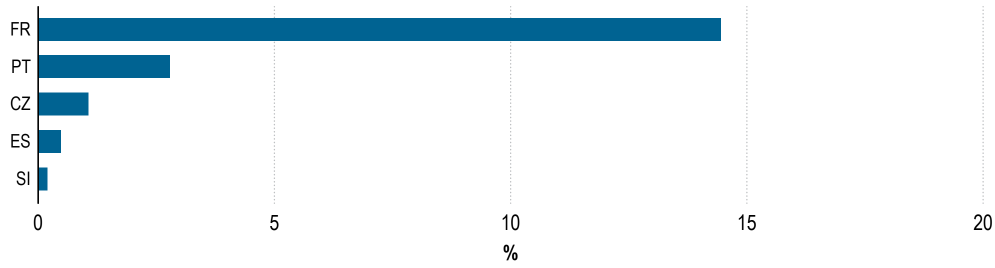
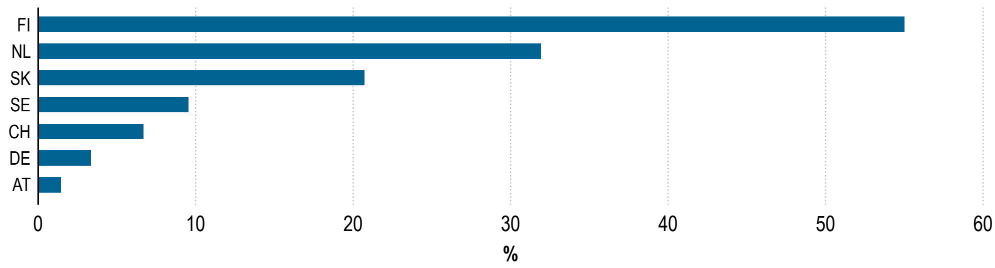


Figure 34: EU balancing capacity contracted abroad as a percentage of the system requirements of reserve capacity (upward FCR) – 2015 (%)

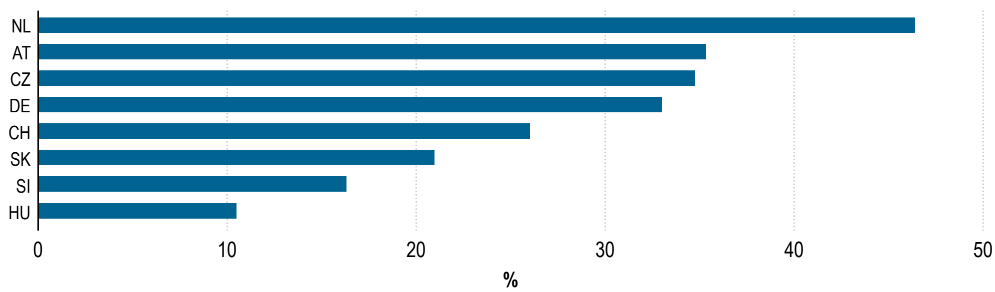


Source: Data provided by NRAs through the EW template (2016) and ACER calculations.

Note: These figures include only those countries that reported some level of cross-border exchange. The actual exchange of balancing energy across borders within the Nordic region is not included in Figure 35, because the Nordic electricity systems are integrated and balanced as one single responsibility area. Therefore, the cross-border exchange of balancing energy cannot be disentangled from imbalance netting across borders and from system imbalance at the (national) TSO level. In the Baltic region, cross border exchanges of various balancing services were reported; however these are not included in Figure 35 and 36 due to discrepancies in the values reported by the relevant NRAs

155 In 2015, the most successfully applied tool to exchange balancing services continued to be the utilisation of imbalance netting across borders. Figure 35 shows that imbalance netting covers an important share of the needs of balancing energy in several European markets. In the Netherlands, imbalance netting avoided almost 50% of the electricity system's balancing energy needs in 2015. The Nordic region is not shown in Figure 35 for the reasons laid out in the note under Figure 33.

Figure 35: Imbalance netting as a percentage of the total need for balancing energy (activated plus avoided activation due to netting) from all types of reserves in national balancing markets – 2015 (%)



Source: Data provided by NRAs through the EW template (2016) and ACER calculations.

Note: This figure includes only those countries that reported some level of cross-border exchange.

10 Capacity mechanisms and generation adequacy

Chapter summary

Several MSs have already implemented or are considering introducing a CM. This Chapter reports on the state of play of the different types of CMs and their stage of implementation in Europe (Section 10.1). This Chapter also presents the state of play of the generation adequacy analysis and the targeted reliability standards reported by MSs (Section 10.2). The Agency recommends that the generation adequacy analysis be performed at a regional or pan-European level[102].

At present, a patchwork of different CMs based on uncoordinated national adequacy assessment methodologies is applied across the EU. This hinders efficient price discovery and investments in generation adequacy. Furthermore, national adequacy assessments and reliability standards are different across the EU. As a result, countries cannot simply rely on the assessment of a neighbouring country and use that as input to their own assessment. Moreover, there is a risk that the contribution to national adequacy from (cross-zonal) interconnectors is reduced. In this respect, standards for harmonisation of adequacy assessments of the ENTSO-E should be further developed. Lastly, as long as cross-border capacity is considered as the residual variable in the overall network security equation, it is likely that the contributions of cross-border capacity to adequacy assessment and of foreign capacity providers in CMs, still remain limited.

10.1 Situation in capacity mechanisms

156 Figure 36 presents an overview of the types of CMs[103] applied in Europe, and shows that Belgium, Finland, France, Ireland and Northern Ireland, Great Britain, Greece, Italy, Lithuania, Poland, Portugal, Spain and Sweden have already implemented a CM.

157 The key changes compared to last year's MMR are that Lithuania has in fact a CM operational since 2010 which resembles features of Strategic Reserves and has a national scope[104]. Additionally, that Denmark's intention to introduce a 200 MW Strategic Reserve mechanism in East-Denmark in 2016 as a transitional measure (until interconnection capacity between East-Denmark and Germany has increased, i.e. the Kriegers Flak interconnection, which is expected to come in operation in 2019) has been put on hold. A cost-benefit analysis of this mechanism is pending, and is aimed at supporting further decision making regarding a potential notification of the European Commission. Furthermore, in Sweden the planned gradual removal of Strategic Reserves has been postponed until 2025.

158 In general, and compared to the same figure[105] presented in last year's MMR, Capacity Payments are being phased out (e.g. in Italy and Greece), while Strategic Reserves, Reliability Options and (decentralised) Capacity Obligations are the most frequently applied schemes.

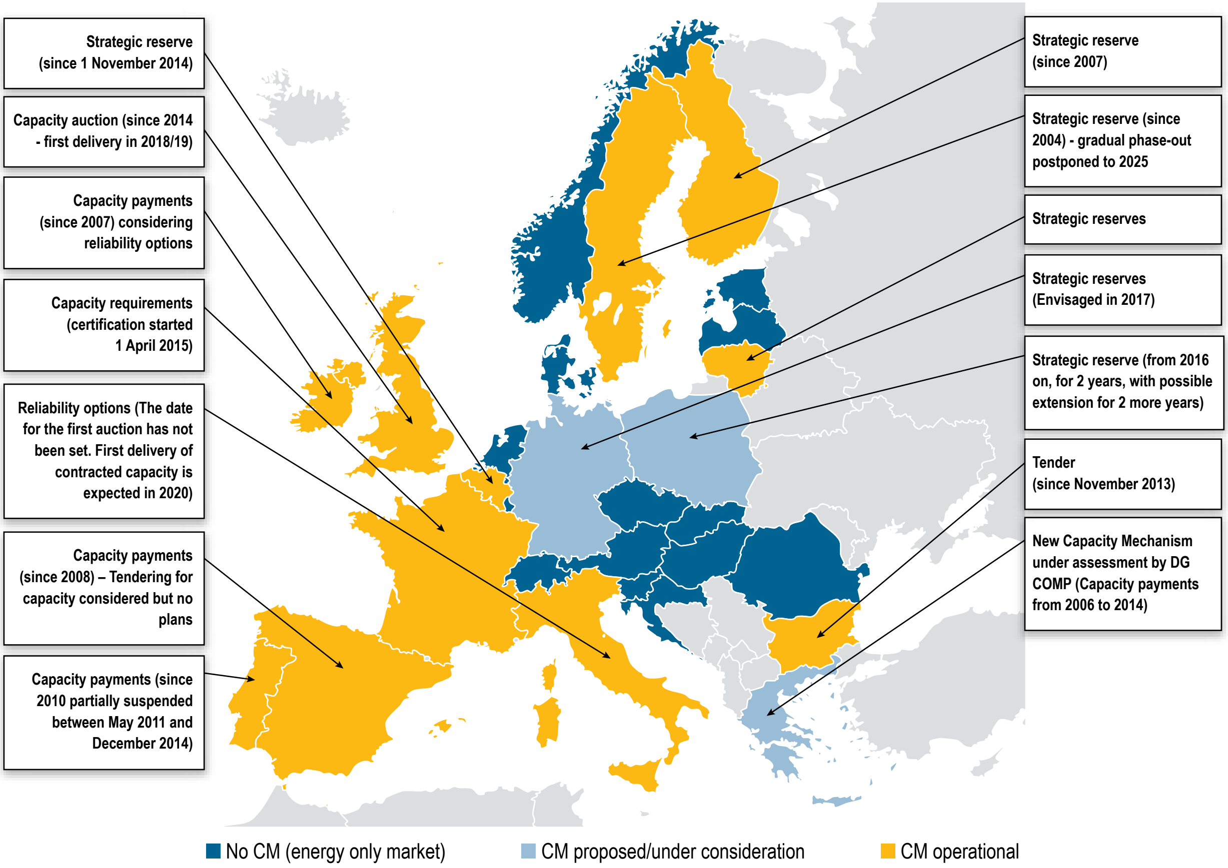
102 See http://www.acer.europa.eu/official_documents/position_papers/position%20papers/acer_ceer_emd_response.pdf, page 5.

103 A variety of CMs have been proposed. They can be classified according to whether they are volume-based or price-based. Volume-based CMs can be further grouped in targeted and market-wide categories. For the taxonomy of the main CMs, see http://europa.eu/rapid/press-release_MEMO-15-4892_en.htm.

104 Pursuant to Article 7.4 and 7.5 of a public service obligation (available here https://www.e-tar.lt/portal/lt/legalAct/TAR.DECA89CB22A0) the government instructs the TSO to contract long-term capacity in order to secure the country's energy security, reliability and energy independency. The TSO pays each year one power plant – only this plant pre-qualifies though, demand respond and all technologies can participate in the scheme – to remain (partly) outside of the market and stay available for the TSO. This power plant was funded in 2015 with a variable payment which is related to the variable costs of the power plant and hence unrelated to the day-ahead market price. The electricity production of the mentioned power plant totalled 1.07 TWh in 2015, but not for the purpose of the public service obligation.

105 See MMR 2014, figure 103.

Figure 36: CMs in Europe – 2015



Source: NRAs (2016) and European Commission's report on the sector inquiry into CMs (2016).

Note: In Germany there are three (envisaged) schemes[106]: Climate Reserve, Network Reserve and a Strategic Capacity Reserve. The first is not considered to be a CM, the second could be and the third is a CM[107]. The Strategic Capacity Reserve is envisaged to be implemented in 2017 provided the necessity is demonstrated. The envisaged CM in Poland for after 2016 includes generation units tendered by the TSO, which would definitely have been decommissioned by the end of 2015. This scheme has the characteristic of a Strategic Reserve CM.

159 The Agency believes that cross-border participation of foreign adequacy suppliers should be allowed in all CMs, except for targeted mechanisms such as Strategic Reserves, because for the latter, provided they are well-designed, investment incentives in generation tend not to be distorted[108]. However, none of the CMs currently in place allow for the participation of foreign adequacy suppliers. The immediate consequence of this is that foreign adequacy providers are discriminated vis-à-vis national adequacy providers. This can distort investment incentives in generation on both sides of borders. Moreover, allowing foreign adequacy suppliers to participate prevents the costly over-procurement of capacities that could arise if each MS used a CM to ensure self-sufficiency.

160 Several MSs are trying to develop or envisage developing schemes that enable cross-border participation in CMs. For example, Great Britain included interconnectors (cross-border transmission lines) in the 2015 capacity auction. Interconnector owners can bid into the capacity auction similarly to generators or demand-side response. In contrast to for instance demand-side response and owners of new generation plants, interconnectors and owners of existing capacity cannot bid above a predetermined threshold without having to justify the need for that. The successful bidders receive one-year capacity agreements at the auction clearing price in return for a capacity obligation requiring the delivery of capacity to Great Britain in a stress

106 See http://www.bmwi.de/DE/Mediathek/publikationen,did=718200.html.

107 See http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_swd_en.pdf, p. 44.

108 See the ACER-CEER's response to the Interim Report of the sector inquiry into CMs, available here: http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2016/ACER%20CEER%20response%20to%20European%20Commission%20CM%20inquiry_0.pdf.

event[109]. Furthermore, France and Ireland are developing plans to allow cross-border participation in their mechanisms. In Italy, external resources are only admitted to participate when the CM reaches “full operational phase”, which is envisaged in 2020.

10.2 Generation adequacy

161 The starting point in the process of determining whether to implement a CM is to assess the generation adequacy situation. Based on the outcomes of such an assessment, MSs can establish whether, and how much, intervention is necessary and, dimension a possible CM accordingly after all no-regret solutions have been implemented. Moreover, a pre-determined reliability standard sets a level of supply security that is deemed appropriate by a MS.

162 Table 8 presents a comprehensive overview of the different metrics that MSs apply to assess their national generation adequacy, with 11 of them performing multiple type analysis, i.e. with different metrics. Moreover, half of the countries perform adequacy assessments using a probabilistic assessment metrics (e.g. LOLP), as opposed to a relatively simple, deterministic assessment metric (e.g. Capacity Margin).

163 Table 8 also shows that, apart from two MSs, no reliability problems have occurred in generation over the last five years. However, no conclusions should be drawn about prospective adequacy problems.

Table 8: Situation of metrics used in EU MSs to assess generation adequacy at national level – 2015

Country	AT	BE	BG	CH	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HR	HU	IE	IT	LT	LU	LV	MA	NL	NO	PL	PT	RO	SE	SI	SK	UK
Reliability Standard	No	Yes	NS	No	NS	No	No	No	No	Yes	No	NS[a]	Yes	NS	Yes	NS2	No	No	NS	NS	No	No	No	No	Yes	NS	No	NS	No	Yes
RMM																														
CM										10%														9%						
EENS																														
EIR																														
LOLE (h/y)		3										3	2.4			8						4			8					3
LOLP (h/y)			13												8															
F&D of expected outages																														
Other	None					NS			NS											NS	NS[c]					NS				
Reliability problems reported in the last five years	No	No	No	No	No	NS	No	No	No	No	No	NS	NS	No	No	No	Yes[b]	No	No	No	No	No	No	Yes[d]	No	NS	No	No	No	No

Sources: ACER, CEER, Assessment of electricity generation adequacy in European countries, Staff Working Document accompanying the Interim Report of the Sector Inquiry on CMs and Pentalateral generation adequacy probabilistic assessment[110].

Note: a Binding reliability standards may either be already in place or implemented in the future; b Reliability problems have arisen on the Islands of Sardinia and Sicily, which are not well connected to mainland Italy; c Generation adequacy assessment is based on a deterministic approach; d A heat wave during August 2015 caused emergency measures to be taken to meet demand. The figures in the table present the reliability standards within the metrics. NS: Not specified. RMM: Reserve Margin Method, CM: Capacity Margin, EENS: Expected Energy Not Supplied, EIR: Energy Index of Reliability, LOLE: Loss of Load Expectation, LOLP: Loss of Load Probability, F&D: frequency and duration of expected outages: a probabilistic risk measure, in terms of the tangible effects on electricity.

164 It is the Agency’s view that generation adequacy assessment should be performed at a pan-European level or at least at a regional level based on harmonised methodologies. This will enhance the cooperation between TSOs and allow properly to take into account the contribution of (cross-zonal) resources and interconnector capacity in adequacy amassments.

109 A penalty regime is in place in the Great Britain CM. Capacity providers that do not deliver sufficient energy at notified times of stress to meet their obligation will be required to repay a proportion of their up-front capacity payments. Interconnectors will face the same penalty as other types of capacity providers. The amount of cross-border capacity participating in the CM is determined by using the maximum capacity of the interconnectors and de-rating according to the probability that they will deliver in a stress event.

110 See http://www.benelux.int/files/4914/2554/1545/Penta_generation_adequacy_assessment_REPORT.pdf.

165 However, these generation adequacy assessments are currently performed on a national basis[111]. An overview of these national assessments is presented in Table 8. With a more common approach – for which ENTSO-E is developing standards and which should be supported and further developed – comparisons between the countries could be made. Moreover, with a more common approach MSs could better rely on the assessment of their neighbours as input for their own assessment. In the absence of a common approach, the potential important contribution from cross-border capacity is not appropriately taken into account. This may lead to over-procurement of capacity in countries with CMs, with a detrimental effect on consumers.

166 However, beyond the need to better coordinate and harmonise the adequacy assessments, it is essential to improve the guaranteed availability of interconnector capacity in order to contribute to adequacy. In this context, in its contribution to the European Commission's Public Consultation on a new Energy Market Design, the Agency stated that some important prerequisites need to be fulfilled in order to make explicit cross-border participation in CMs possible and beneficial. These prerequisites focus on the way interconnector capacity is made available and, hence, contribute to national adequacy requirements:

a) TSOs are incentivised to make a sufficient and appropriate amount of cross-border capacities available for cross-border trade throughout the year(s);

b) TSOs are not allowed to adjust, limit or reserve these cross-border transmission capacities at any point in time, including in cases of shortages; and

c) TSOs agree ex-ante on the treatment of local/foreign adequacy providers in the event of a widespread shortage situation (i.e. when a shortage affects at least two countries simultaneously).

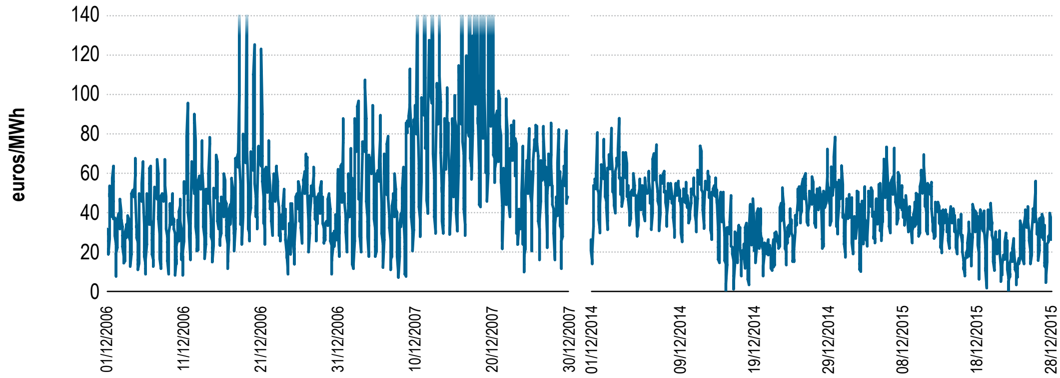
167 While the fulfilment of condition c) goes beyond the remit of NRAs and requires the strong involvement and commitment of MSs, conditions a) and b) are more in the realm of NRAs.

168 Furthermore, the Agency stresses the importance of the CACM Regulation implementation and, in particular, the development of new capacity calculation methodologies that can create/increase the reliance on the ability of cross-zonal flows to contribute to the solution of national adequacy issues. The implementation of these methodologies should maximise the capacity allocated to the market, while respecting operational security, and prevent TSOs from reducing capacities at any point in time, including in the event of simultaneous market scarcity situations.

111 An exception is the following report assessing adequacy for Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland, see footnote 110.

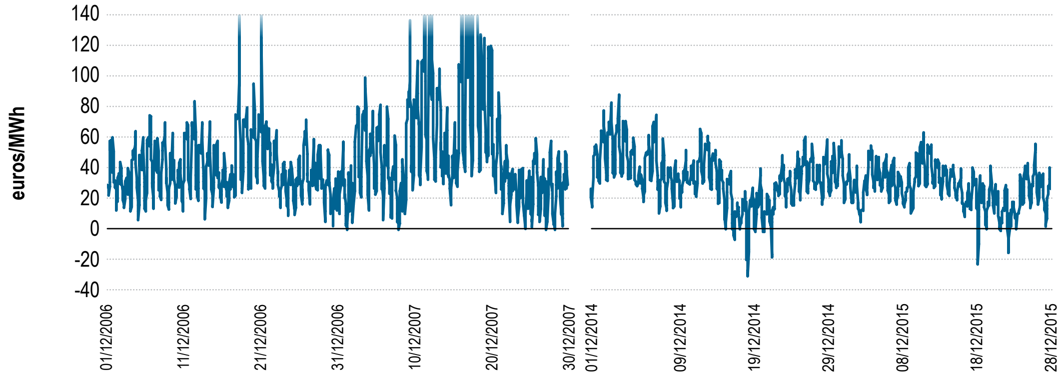
11 Annex

Figure 37: Hourly DA prices in France – December 2006, 2007, 2014 and 2015 (euros/MWh)



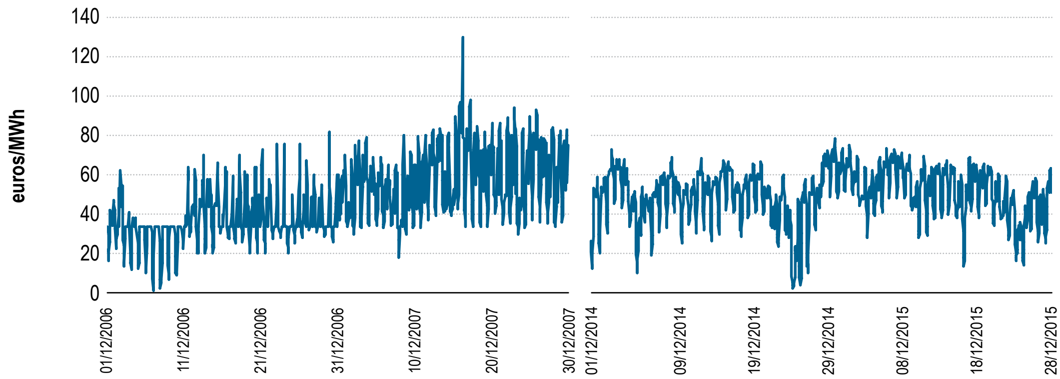
Source: EMOS, Platts (2016).

Figure 38: Hourly DA prices in Germany – December 2006, 2007, 2014 and 2015 (euros/MWh)



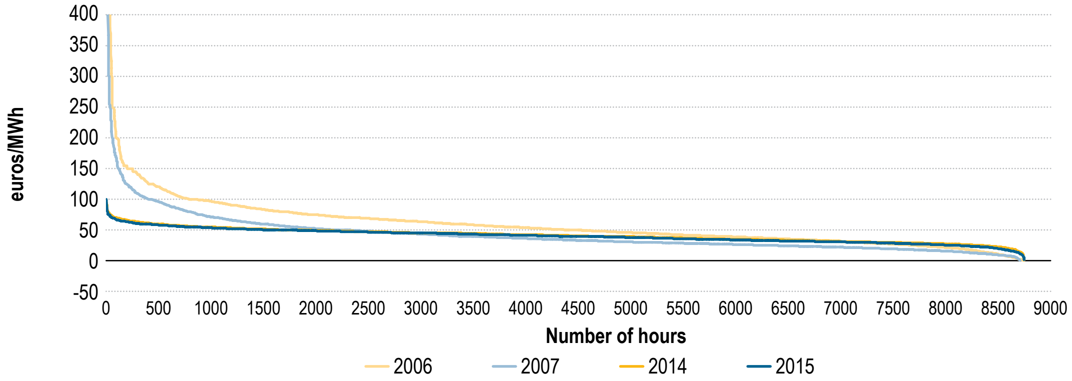
Source: EMOS, Platts (2016).

Figure 39: Hourly DA prices in Spain – December 2006, 2007, 2014 and 2015 (euros/MWh)



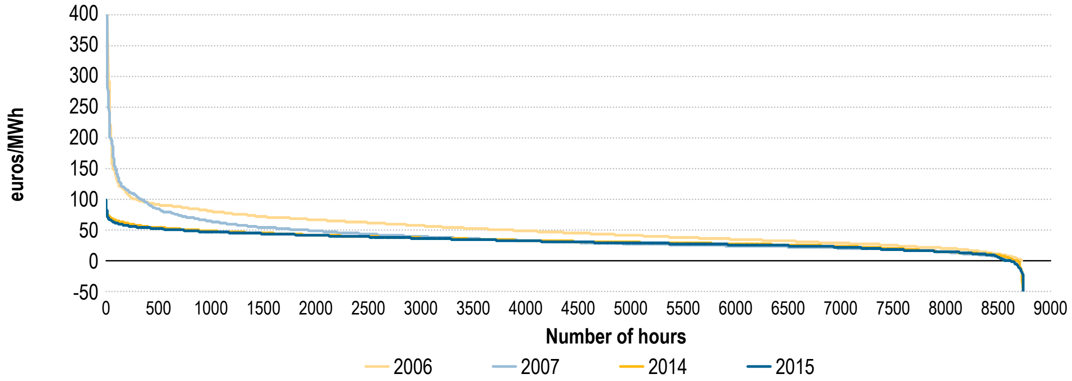
Source: EMOS, Platts (2016).

Figure 40: DA price duration curve in the Netherlands – 2006, 2007, 2014 and 2015 (euros/MWh)



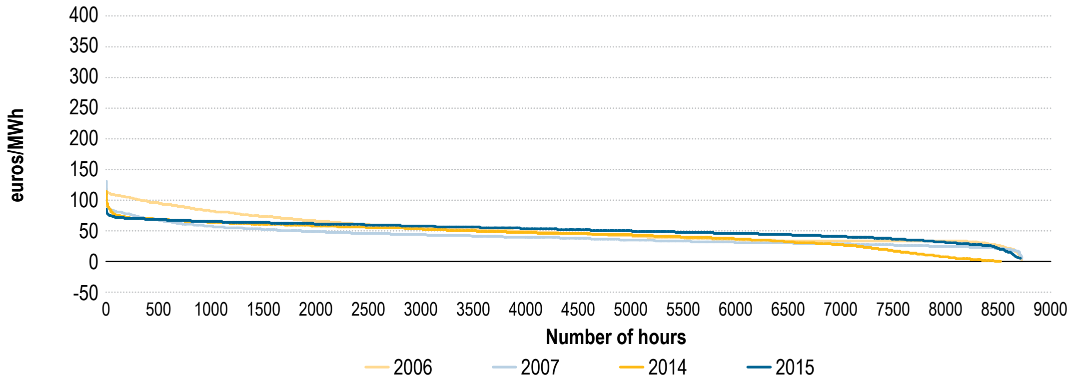
Source: EMOS, Platts (2016).

Figure 41: DA price duration curve in Germany – 2006, 2007, 2014 and 2015 (euros/MWh)



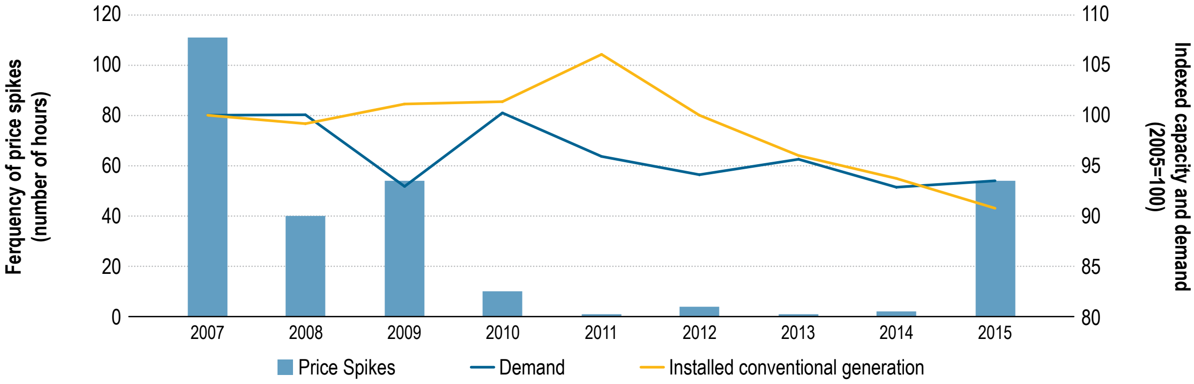
Source: EMOS, Platts (2016).

Figure 42: DA price duration curve in Spain – 2006, 2007, 2014 and 2015 (euros/MWh)



Source: EMOS, Platts (2016).

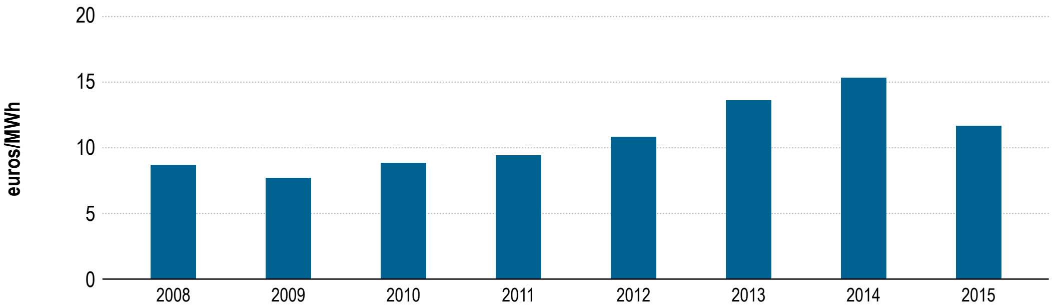
Figure 43: Evolution of the frequency of price spikes (number of hours per year, left axis) and the aggregated installed conventional generation capacity and aggregated electricity demand (indexed to 2005 = 1, right axis) in Belgium – 2007–2015



Source: Eurostat, ENTSO-E (2016).

Note: The figures on conventional generation capacity are based on the Eurostat categories of "Electrical capacity, main activity producers – Combustible Fuels, Hydro and Nuclear". For 2014, the figures on conventional generation capacity are based on 2014 Eurostat figures and the relative change in 2015 compared to 2014 recorded by ENTSO-E in its equivalent categories. The figures on demand are based on ENTSO-E data.

Figure 44: Charges to household end-consumers that finance the costs associated with CMs, redispatching actions and other system services in Italy – 2008–2015 (euros/MWh)



Source: AEEGSI (2016).

Note: The charges shown in the figure represent the so-called "Pd" component included in the standard offer for households in Italy.

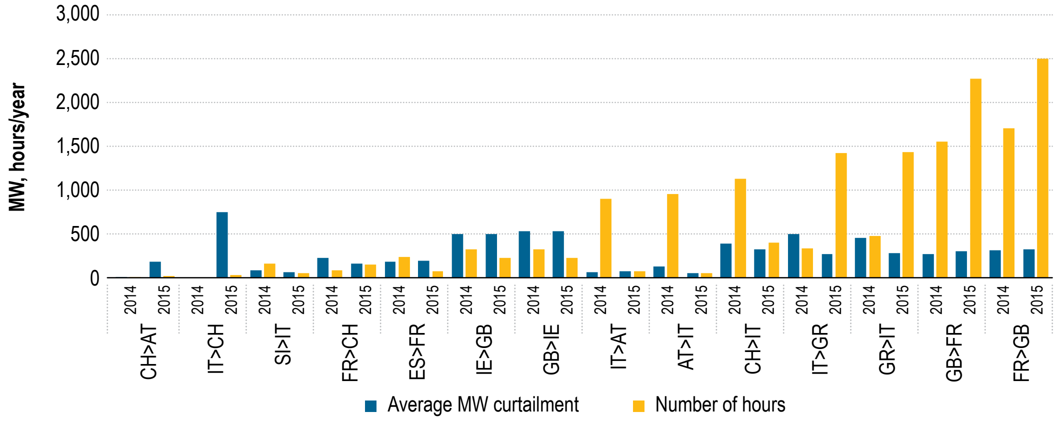
Table 9: Change in tradable capacities in Europe – 2014–2015 (MW, %)

Region	Border	Direction	NTC 2014 (MW)	NTC 2015 (MW)	Change (MW)	Change (%)
BALTIC	EE-FI	EE>FI	837,6	891,9	54	6%
BALTIC	EE-FI	FI>EE	795,0	933,8	139	17%
BALTIC	EE-LV	EE>LV	781,1	728,8	-52	-7%
BALTIC	EE-LV	LV>EE	808,7	620,0	-189	-23%
BALTIC	LT-LV	LT>LV	485,2	535,5	50	10%
BALTIC	LT-LV	LV>LT	921,3	978,2	57	6%
CEE	AT-CZ	AT>CZ	619,5	645,9	26	4%
CEE	AT-CZ	CZ>AT	586,5	561,5	-25	-4%
CEE	AT-HU	AT>HU	514,3	510,2	-4	-1%
CEE	AT-HU	HU>AT	599,4	620,4	21	4%
CEE	AT-SI	AT>SI	684,5	762,5	78	11%
CEE	AT-SI	SI->AT	946,2	939,7	-7	-1%
CEE	CZ+DE+SK-PL	CZ+DE+ SK>PL	2,6	0,0	-3	-100%
CEE	CZ+DE+SK-PL	PL>CZ+ DE+SK	809,2	674,3	-135	-17%
CEE	CZ+PL- DE_50HZT	CZ+PL> DE_50HZT	1361,2	1234,4	-127	-9%
CEE	CZ+PL- DE_50HZT	DE_50HZT> CZ+PL	660,6	432,7	-228	-35%
CEE	CZ-DE_TENNET	CZ> DE_TENNET	1361,2	1225,2	-136	-10%
CEE	CZ-DE_TENNET	DE_TENNET> CZ	660,6	423,5	-237	-36%
CEE	CZ-PL	CZ>PL	598,2	598,4	0	0%
CEE	CZ-PL	PL>CZ	639,5	656,2	17	3%
CEE	CZ-SK	CZ>SK	1671,8	1692,1	20	1%
CEE	CZ-SK	SK>CZ	1186,8	1180,3	-7	-1%
CEE	HU-SK	HU>SK	761,4	787,9	27	3%
CEE	HU-SK	SK>HU	1095,5	1012,6	-83	-8%
CEE	PL-SK	PL>SK	490,6	536,4	46	9%
CEE	PL-SK	SK>PL	452,3	488,4	36	8%
CSE	AT-CH	AT>CH	612,3	778,3	166	27%
CSE	AT-CH	CH>AT	1192,8	1181,7	-11	-1%
CSE	AT-IT	AT>IT	217,0	249,8	33	15%
CSE	AT-IT	IT>AT	96,3	104,5	8	8%
CSE	CH-DE	CH>DE	3999,5	3933,9	-66	-2%
CSE	CH-DE	DE>CH	1094,1	1398,4	304	28%
CSE	CH-FR	CH>FR	1107,7	1183,8	76	7%
CSE	CH-FR	FR>CH	3093,3	3064,1	-29	-1%
CSE	CH-IT	CH>IT	2549,4	2914,3	365	14%
CSE	CH-IT	IT>CH	1716,9	1695,6	-21	-1%
CSE	FR-IT	FR>IT	2267,5	2456,9	189	8%
CSE	FR-IT	IT>FR	1020,6	1018,9	-2	0%
CSE	GR-IT-BRI	GR> IT-BRI	223,8	382,7	159	71%
CSE	GR-IT-BRI	IT-BRI> GR	223,8	382,5	159	71%
CSE	HR-SI	HR>SI	1379,9	1453,7	74	5%
CSE	HR-SI	SI>HR	1446,8	1453,7	7	0%
CSE	IT-SI	IT>SI	649,2	636,1	-13	-2%
CSE	IT-SI	SI>IT	488,2	526,3	38	8%
F-UK-I	FR-UK	FR>UK	1829,1	1804,6	-25	-1%
F-UK-I	FR-UK	UK>FR	1829,1	1804,6	-25	-1%
F-UK-I	IEEWIC-UK	IEEWIC>UK	483,5	488,1	5	1%
F-UK-I	IEEWIC-UK	UK>IEEWIC	512,5	517,4	5	1%
F-UK-I	FR-UK	FR>UK	1829,1	1804,6	-25	-1%
F-UK-I	FR-UK	UK>FR	1829,1	1804,6	-25	-1%
F-UK-I	IEEWIC-UK	IEEWIC >UK	483,5	488,1	5	1%
F-UK-I	IEEWIC-UK	UK>I EWIC	512,5	517,4	5	1%
F-UK-I	IEMOYLE-UK	IEMOYLE> UK	203,5	246,7	43	21%
F-UK-I	IEMOYLE-UK	UK> IEMOYLE	205,4	246,7	41	20%
F-UK-I	NL-UK	NL>UK	852,5	989,8	137	16%
F-UK-I	NL-UK	UK>NL	852,5	992,6	140	16%
NORDIC	DE_50HZT- DK_E	DE_50HZT >DK_E	574,0	568,3	-6	-1%
NORDIC	DE_50HZT- DK_E	DK_E> DE_50HZT	559,7	543,0	-17	-3%
NORDIC	DE_TENNET- DK_W	DE_TENNET >DK_W	901,0	864,4	-37	-4%
NORDIC	DE_TENNET- DK_W	DK_W> DE_TENNET	509,1	235,7	-273	-54%
NORDIC	DE_TENNET- SE-4	DE_TENNET >SE-4	323,2	158,8	-164	-51%
NORDIC	DE_TENNET- SE-4	SE-4> DE_TENNET	447,5	275,2	-172	-39%
NORDIC	DK_E-SE-4	DK_E>SE-4	1390,0	1537,5	147	11%
NORDIC	DK_E-SE-4	SE-4>DK_E	1173,9	1174,1	0	0%
NORDIC	DK_W-NO-2	DK_W>NO-2	852,5	1407,0	554	65%
NORDIC	DK_W-NO-2	NO-2>DK_W	807,2	1332,8	526	65%
NORDIC	DK_W-SE-3	DK_W>SE-3	521,1	535,6	15	3%
NORDIC	DK_W-SE-3	SE-3>DK_W	558,9	528,0	-31	-6%
NORDIC	FI-SE-1	FI>SE-1	1056,5	1070,0	13	1%
NORDIC	FI-SE-1	SE-1>FI	1399,5	1410,9	11	1%
NORDIC	FI-SE-3	FI>SE-3	1181,0	1166,3	-15	-1%
NORDIC	FI-SE-3	SE-3>FI	1179,7	1142,8	-37	-3%
NORDIC	NL-NO-2	NL>NO-2	678,1	691,2	13	2%
NORDIC	NL-NO-2	NO-2>NL	663,9	667,3	3	1%
NORDIC	NO-1-SE-3	NO-1>SE-3	1635,8	1855,7	220	13%
NORDIC	NO-1-SE-3	SE-3>NO-1	1611,3	1843,6	232	14%
NORDIC	NO-3-SE-2	NO-3>SE-2	590,2	590,5	0	0%
NORDIC	NO-3-SE-2	SE-2>NO-3	890,2	721,8	-168	-19%
NORDIC	NO-4-SE-1	NO-4>SE-1	606,1	387,0	-219	-36%
NORDIC	NO-4-SE-1	SE-1>NO-4	429,0	373,4	-56	-13%
NORDIC	NO-4-SE-2	NO-4>SE-2	141,4	117,8	-24	-17%
NORDIC	NO-4-SE-2	SE-2>NO-4	218,0	145,4	-73	-33%
NORDIC	PL-SE-4	PL>SE-4	109,8	78,3	-32	-29%
NORDIC	PL-SE-4	SE-4>PL	373,4	386,6	13	4%
SEE	BG-GR	BG>GR	422,9	530,9	108	26%
SEE	BG-GR	GR>BG	316,3	380,3	64	20%
SEE	BG-RO	BG>RO	117,6	264,5	147	125%
SEE	BG-RO	RO>BG	93,3	178,5	85	91%
SEE	HR-HU	HR>HU	1000,0	1000,0	0	0%
SEE	HR-HU	HU>HR	1200,0	1200,0	0	0%
SEE	HU-RO	HU>RO	351,5	609,6	258	73%
SEE	HU-RO	RO>HU	349,0	639,2	290	83%
SWE	ES-FR	ES>FR	861,1	1131,5	270	31%
SWE	ES-FR	FR>ES	1044,9	1313,5	269	26%
SWE	ES-PT	ES>PT	1980,3	2147,5	167	8%
SWE	ES-PT	PT>ES	2068,7	2780,7	712	34%

Source: Vulcanus, ENTSO-E, JAO and Nord Pool Spot (2016).

Note: In 2015 NTC values on borders where FBMC was implemented are available only until May 20. The average presented in the table is the average NTC between 1 January and 20 May.

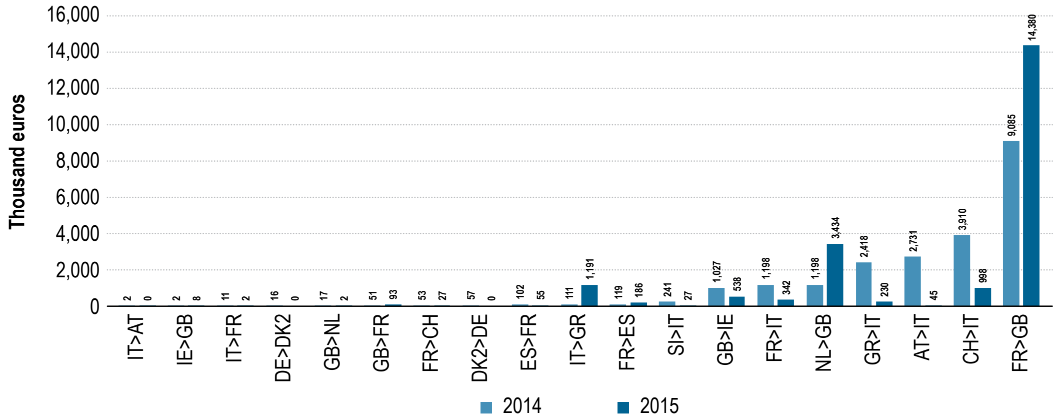
Figure 45: Average curtailed capacity and number of curtailed hours per border – 2014 and 2015 (MW and hours/year)



Source: Data provided by NRAs through the EW template (2016), EW template (2016) and ACER calculations.

Note: In this figure, "curtailment" is defined as "LT capacity curtailment". It refers to a situation in which the sum of monthly and yearly auctioned capacity is higher in a specific hour than the DA NTC value in the same hour. For some borders, the data provided on the two sides of the borders were not identical. In these cases, average values are reported. Only borders with more than 20 hours of curtailments per year are included in this figure. Data for GB-IE refers to the East-West interconnector.

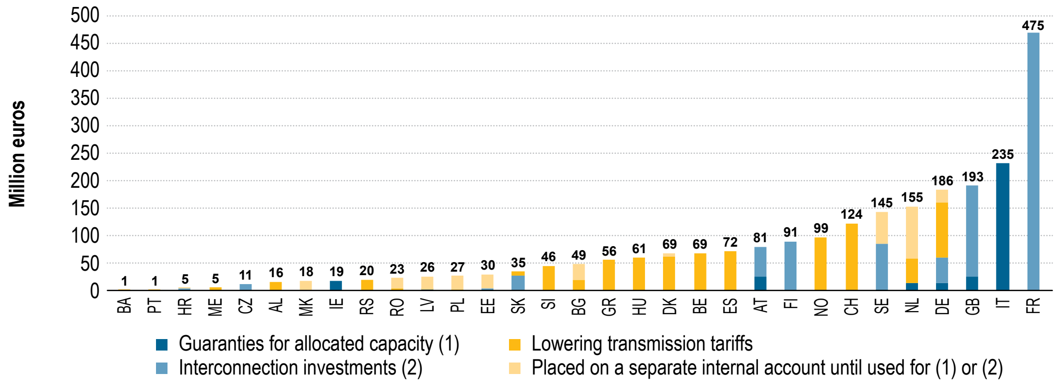
Figure 46: Total curtailment costs per border – 2014 and 2015 (thousand euros)



Source: Data provided by NRAs through the EW template (2016), and ACER calculations.

Note: On the borders where the data provided by the two NRAs were not identical, the average curtailment costs are reported. Data for GB-IE refers to East-West interconnector.

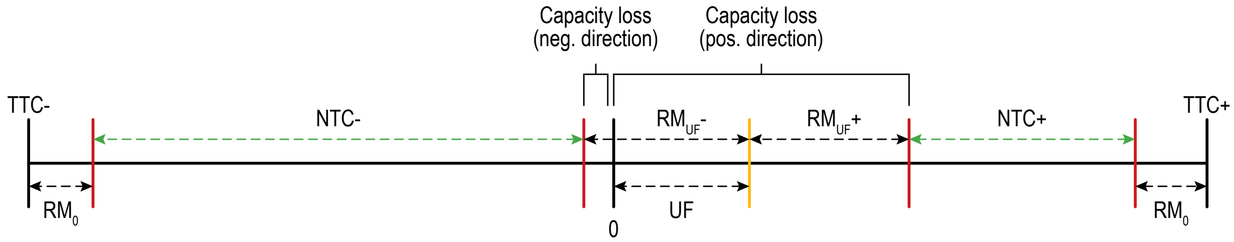
Figure 47: Congestion revenues per country – 2015 (million euros)



Source: Data provided by ENTSO-E (2016).

To estimate the loss of capacity on a specific bidding zone border due to UFs, we consider the bidding zone border as if it consisted of one HVAC interconnector[112], which can accommodate a physical flow equal to total transfer capacity (TTC) in a positive or negative direction. The capacity of the interconnector is then reduced by the volume of forecast UF (increase of capacity in one direction and decrease in the opposite direction). To take into account the uncertainty of UFs, the capacity of the interconnector is further reduced by the RMUF (reliability margin due to UFs decrease of capacity in both directions). Finally, the capacity is also reduced due to other uncertainties (i.e. RM_0, which also reduces capacity in both directions). The process is described in Figure 48 and shows that the capacity of the interconnector can be reduced in both directions, although one would intuitively expect that capacity would increase in the direction opposite to UFs. The results of the capacity loss assessment are presented separately for UFs, UAFs and LFs in Table 11.

Figure 48: Illustration of capacity loss



Source: ACER.

112 The reasoning can be expanded to bidding zone borders with several HVAC interconnectors. However, UFs do not exist on HVDC interconnectors.

Table 10: Estimated loss of social welfare due to UFs, LFs and UAFs (million euros)

	Year	Welfare	CH-AT	CH-DE	CH-FR	CH-IT	AT-SI	FR-BE	FR-DE	FR-IT	IT-AT	IT-SI	BE-NL	DE-NL	DE-PL	DE-CZ	DE-AT	AT-CZ	AT-HU	PL-CZ	PL-SK	CZ-SK	SK-HU	TOTAL	Grand Total	% of WL induced by LF (UAF)
UFs	2011	loss	50.88	136.73	16.93	92.93	12.21	4.09	74.49	96.70	16.99	49.44	32.92	9.04	31.25	20.57	0.00	28.03	13.62	44.61	25.88	1.41	34.16	792.91	792.91	
		gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	2012	loss	91.00	163.45	44.57	200.23	21.35	15.57	11.32	105.95	26.12	67.72	12.04	85.26	43.56	21.58	0.00	27.70	16.76	44.37	21.82	3.30	57.29	1,080.96	1,080.96	
		gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	2013	loss	81.82	151.31	36.71	115.89	17.02	13.49	30.02	72.20	18.21	86.36	34.16	203.92	46.96	24.25	0.00	34.59	18.42	47.19	25.18	3.70	31.51	1,092.92	1,092.92	
		gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	2014	loss	40.99	88.73	24.22	110.67	20.00	33.26	43.02	43.65	13.15	47.96	16.71	127.17	175.89	17.54	0.00	21.45	22.91	10.47	11.05	2.07	40.03	910.95	910.95	
		gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
	2015	loss	79.03	206.49	27.03	101.44	33.84	17.07	12.49	43.06	11.17	65.49	106.88	140.05	137.16	22.30	0.00	23.36	22.42	20.19	19.36	4.10	43.87	1,136.80	1,136.80	
		gain	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
LFs	2011	loss	14.78	47.64	3.70	80.15	6.39	0.08	38.43	8.90	23.78	21.45	6.37	8.06	21.32	10.00	0.00	8.86	9.37	36.44	13.58	1.25	28.38	388.92	322.86	40.7%
		gain	-0.25	-0.09	-0.16	-0.55	-3.91	-0.52	-0.04	-36.98	-0.69	-8.05	-4.65	-0.09	-4.48	-1.40	0.00	-0.13	-0.42	-2.38	-0.38	0.00	-0.89	-66.06		
	2012	loss	42.62	32.16	13.10	105.31	12.48	3.15	5.05	29.06	26.36	47.22	5.40	47.49	31.12	9.34	0.00	7.41	29.10	37.12	14.02	5.99	76.41	579.90	522.55	48.3%
		gain	-0.21	-1.03	-0.50	-4.63	-4.58	-1.47	-1.05	-23.67	-2.00	-5.91	-2.85	-0.05	-0.62	-1.83	0.00	-0.08	-1.43	-1.69	-1.56	-0.02	-2.18	-57.36		
	2013	loss	31.27	39.47	7.78	67.96	9.44	1.86	14.33	22.08	15.39	31.50	9.19	122.42	34.97	12.15	0.00	9.05	8.35	34.20	14.47	3.25	26.00	515.17	446.39	40.8%
		gain	-0.48	-1.47	-0.21	-2.26	-3.34	-8.36	-0.34	-14.15	-0.69	-14.57	-8.46	-0.03	-4.79	-1.73	0.00	-0.28	-4.02	-3.22	-0.37	0.00	-0.01	-68.78		
	2014	loss	32.40	21.20	7.23	44.16	13.11	1.34	23.92	18.82	10.55	26.19	8.56	81.56	120.97	6.07	0.00	7.76	9.25	6.21	7.13	2.51	29.58	478.51	413.27	45.4%
		gain	-0.93	-1.92	-0.58	-4.90	-2.04	-17.22	-0.53	-17.08	-2.13	-7.67	-1.46	-0.03	-0.18	-0.59	0.00	-0.05	-4.16	-3.20	-0.36	0.00	-0.20	-65.24		
	2015	loss	31.31	57.82	9.74	32.30	9.73	3.66	5.09	22.31	7.18	39.91	61.32	72.35	85.24	7.21	0.00	6.33	6.14	12.85	7.64	5.27	38.03	521.41	454.12	39.9%
		gain	-1.01	-1.48	-0.42	-7.88	-10.62	-4.27	-2.83	-10.61	-2.21	-2.48	-0.68	-0.15	-0.09	-1.47	0.00	-0.03	-19.06	-1.23	-0.76	0.00	-0.01	-67.29		
UAFs	2011	loss	36.49	89.35	13.89	26.81	10.74	4.53	36.11	125.61	4.82	40.01	31.47	2.13	15.08	13.89	0.00	19.43	6.96	11.40	13.15	0.37	10.42	512.66	470.04	59.3%
		gain	-0.14	-0.17	-0.51	-13.48	-1.01	0.00	0.00	-0.82	-10.92	-3.97	-0.27	-1.06	-0.67	-1.92	0.00	-0.13	-2.29	-0.84	-0.46	-0.20	-3.75	-42.62		
	2012	loss	48.69	133.13	32.67	104.23	14.84	14.12	7.33	104.52	11.65	36.98	9.94	38.58	13.12	17.09	0.00	20.77	6.83	11.18	10.92	0.10	7.62	644.30	558.42	51.7%
		gain	-0.09	-0.80	-0.69	-4.68	-1.39	-0.23	0.00	-3.95	-9.88	-10.57	-0.46	-0.77	-0.06	-3.01	0.00	-0.40	-17.75	-2.24	-1.56	-2.77	-24.56	-85.88		
	2013	loss	51.12	114.35	29.83	55.16	12.84	20.14	16.06	69.58	6.54	71.54	33.73	87.96	18.42	17.58	0.00	25.93	15.15	16.58	11.46	0.57	6.48	681.04	646.53	59.2%
		gain	-0.09	-1.05	-0.69	-4.97	-1.92	-0.16	-0.03	-5.32	-3.02	-2.11	-0.29	-6.43	-1.65	-3.75	0.00	-0.11	-1.07	-0.37	-0.39	-0.12	-0.96	-34.51		
	2014	loss	12.79	70.22	18.50	73.82	10.53	49.38	19.83	47.59	7.39	31.66	9.84	52.54	55.44	13.29	0.00	13.77	18.20	7.51	5.32	0.34	13.47	531.44	497.68	54.6%
		gain	-3.26	-0.76	-0.92	-2.41	-1.60	-0.23	-0.20	-5.67	-2.67	-2.23	-0.24	-6.91	-0.33	-1.23	0.00	-0.04	-0.39	-0.05	-1.04	-0.77	-2.81	-33.76		
	2015	loss	49.74	150.56	18.42	78.02	35.96	18.10	10.64	38.33	7.91	32.26	46.81	68.90	52.02	17.98	0.00	17.33	36.63	8.57	12.52	0.36	8.36	709.43	682.69	60.1%
		gain	-1.00	-0.42	-0.71	-0.99	-1.24	-0.42	-0.40	-6.98	-1.70	-4.20	-0.57	-1.04	-0.01	-1.43	0.00	-0.27	-1.29	0.00	-0.04	-1.53	-2.51	-26.74		

Source: ACER.

Table 11: Estimated capacity loss (-) and capacity gain (+) due to UFs, LFs and UAFs (MW)

Capacity loss/gain (MW)	year	direction	CH>AT	CH>DE	CH>FR	CH>IT	AT>SI	FR>BE	FR>DE	FR>IT	IT>AT	IT>SI	BE>NL	DE>NL	DE>PL	DE>CZ	DE>AT	AT>CZ	AT>HU	PL>CZ	PL>SK	CZ>SK	SK>HU
UFs	2011	indicated	-80	517	-2,703	-838	-166	-742	-3,310	-392	-187	-261	-733	-951	-1,448	-821	-570	42	-328	-1,076	-506	-524	-414
		opposite	-931	-2,435	701	-456	-559	-964	775	-850	-89	-439	-945	-732	161	-410	-1,813	-1,340	-404	123	-110	-287	-344
	2012	indicated	132	80	-2,287	-1,031	-118	-70	-3,672	-284	-186	-346	-66	-1,604	-1,613	-940	-321	182	-152	-1,180	-569	-604	-585
		opposite	-1,143	-1,998	285	-263	-607	-1,636	1,137	-958	-90	-354	-1,612	-79	326	-291	-2,062	-1,480	-580	227	-47	-207	-173
	2013	indicated	52	-75	-2,216	-873	-187	-86	-3,591	-282	-196	-171	-88	-1,577	-1,437	-1,142	-397	243	-291	-1,078	-502	-641	-599
		opposite	-1,063	-1,843	214	-421	-538	-1,620	1,056	-960	-80	-529	-1,590	-106	150	-89	-1,986	-1,541	-441	125	-114	-170	-159
	2014	indicated	-171	25	-2,217	-961	-184	-205	-3,597	-185	-170	-195	-205	-1,632	-1,780	-1,150	-18	497	-252	-1,224	-757	-518	-642
		opposite	-959	-1,981	-16	-367	-559	-1,674	925	-1,070	-86	-574	-1,659	-228	475	-108	-2,503	-1,837	-488	280	96	-305	-127
	2015	indicated	-344	-90	-2,161	-945	-304	-117	-3,694	-279	-207	-151	-134	-1,848	-2,195	-1,102	290	781	-227	-1,463	-966	-403	-674
		opposite	-904	-1,965	-178	-492	-471	-1,897	891	-1,090	-52	-669	-1,880	-154	815	-243	-2,947	-2,165	-530	511	250	-480	-161
LFs	2011	indicated	-110	118	-490	-696	170	203	-1,461	154	-42	-238	201	-835	-1,177	37	-67	-46	-92	-966	-283	-424	-482
		opposite	-323	-794	-78	74	-504	-834	775	-631	-133	-130	-826	197	495	-495	-658	-413	-231	436	-25	39	92
	2012	indicated	98	-340	-402	-542	49	405	-1,399	-10	-97	-183	397	-1,021	-1,104	55	-225	-82	-222	-1,005	-335	-701	-722
		opposite	-532	-336	-165	-81	-383	-1,036	714	-467	-78	-185	-1,022	382	422	-513	-500	-377	-100	474	28	317	331
	2013	indicated	49	-374	-340	-509	93	422	-1,257	-138	-110	-261	410	-1,025	-1,180	19	-136	-54	37	-938	-311	-398	-459
		opposite	-483	-302	-227	-113	-427	-1,053	571	-340	-65	-107	-1,035	387	498	-476	-589	-405	-360	407	4	13	69
	2014	indicated	177	-482	-351	-418	-15	478	-1,406	-110	-90	-118	494	-1,153	-1,279	-148	-118	144	23	-1,026	-340	-429	-524
		opposite	-660	-195	-236	-215	-327	-1,151	651	-385	-64	-290	-1,165	463	611	-348	-661	-660	-371	512	20	47	135
	2015	indicated	-59	-288	-622	-285	68	364	-1,476	-260	-136	-88	351	-1,057	-1,364	-66	-109	-2	335	-1,020	-420	-434	-582
		opposite	-447	-405	23	-368	-421	-1,093	663	-263	-14	-345	-1,080	315	706	-485	-715	-558	-733	521	126	66	185
UAFs	2011	indicated	31	399	-2,214	-142	-336	-944	-1,849	-546	-145	-23	-934	-115	-271	-858	-503	88	-237	-109	-224	-100	68
		opposite	-608	-1,641	779	-529	-56	-130	-1	-218	43	-309	-119	-929	-334	84	-1,154	-927	-173	-313	-85	-326	-436
	2012	indicated	34	420	-1,886	-489	-167	-474	-2,272	-274	-89	-163	-463	-583	-508	-995	-96	264	70	-175	-233	97	137
		opposite	-611	-1,662	451	-182	-224	-600	423	-491	-13	-169	-590	-462	-96	222	-1,562	-1,103	-480	-247	-75	-523	-504
	2013	indicated	3	299	-1,875	-364	-281	-508	-2,334	-144	-86	91	-498	-551	-257	-1,161	-261	296	-328	-140	-191	-243	-140
		opposite	-581	-1,541	441	-307	-111	-566	484	-620	-15	-422	-555	-493	-348	387	-1,397	-1,135	-82	-282	-118	-183	-227
	2014	indicated	-348	507	-1,866	-544	-169	-683	-2,191	-75	-80	-77	-699	-479	-501	-1,002	100	354	-275	-199	-417	-89	-118
		opposite	-299	-1,786	220	-152	-231	-524	274	-686	-21	-285	-495	-691	-136	240	-1,842	-1,177	-117	-232	76	-352	-263
	2015	indicated	-285	198	-1,539	-660	-372	-482	-2,218	-19	-70	-63	-486	-791	-831	-1,037	399	782	-562	-443	-546	31	-92
		opposite	-457	-1,560	-201	-124	-50	-804	229	-827	-38	-323	-800	-469	109	242	-2,232	-1,606	203	-10	125	-546	-346

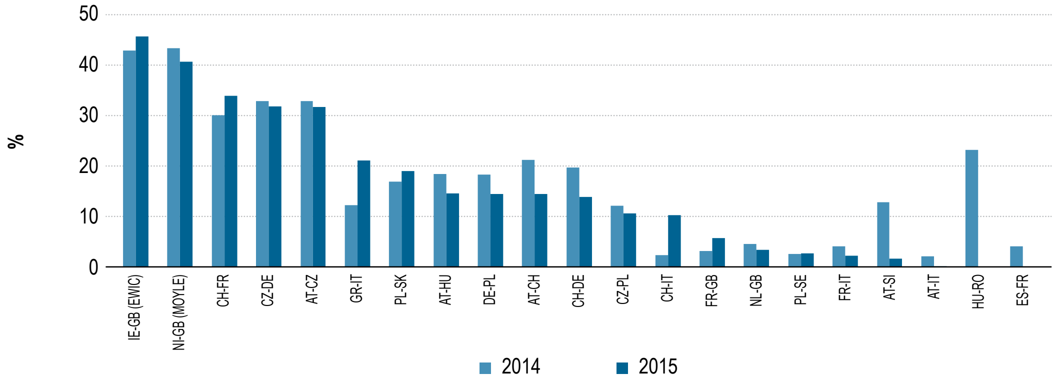
Source: ACER.

Table 12: Flow statistics – (MW, GWh)

Flows	year		CH>AT	CH>DE	CH>FR	CH>IT	AT>SI	FR>BE	FR>DE	FR>IT	IT>AT	IT>SI	BE>NL	DE>NL	DE>PL	DE>CZ	DE>AT	AT>CZ	AT>HU	PL>CZ	PL>SK	CZ>SK	SK>HU	TOTAL	Grand Total	% of LF (UAF) in UF
Average SCHs (MW)	2011		-160	-83	-2,897	2,679	423	660	269	1,836	-170	-454	381	629	-284	-1,068	1,385	-429	149	235	142	732	891			
	2012		-267	-58	-2,005	2,422	752	1,362	-993	1,720	-175	-422	280	1,726	-309	-981	1,994	-326	456	170	136	926	958			
	2013		-243	-22	-1,906	2,313	331	1,476	-1,119	1,753	-227	-412	351	2,045	-241	-1,322	1,789	-286	116	149	152	584	726			
	2014		-207	221	-1,927	2,398	481	1,889	-677	2,204	-214	-388	-37	2,052	-92	-793	2,440	-164	348	17	-27	959	812			
	2015		-480	-550	-1,618	2,671	613	1,847	-1,082	2,252	-248	-444	-542	1,845	-295	-413	3,268	68	392	39	-44	1,170	861			
Average LFs (MW)	2011		-107	-454	250	312	-237	-454	1,155	-444	-89	-30	-448	449	731	-266	-296	-184	-3	633	93	186	229			
	2012		-317	6	159	163	-127	-662	1,090	-275	-30	-77	-651	640	661	-283	-136	-147	-42	622	40	191	227			
	2013		-267	35	140	93	-124	-629	968	-174	-50	-31	-614	595	676	-248	-227	-177	-101	568	100	139	175			
	2014		-424	142	58	99	-152	-805	1,034	-137	13	-84	-816	789	952	-101	-272	-398	-200	774	179	236	326			
	2015		-195	-54	325	-46	-244	-725	1,066	3	63	-127	-712	685	1,044	-215	-307	-276	-537	774	271	254	389			
Average UAFs (MW)	2011		-320	-1,017	1,453	-115	41	356	882	211	138	-54	351	-351	90	475	-350	-525	-39	-16	110	-68	-193			
	2012		-322	-1,039	1,133	224	-113	-115	1,320	-69	77	74	-121	117	317	611	-746	-695	-175	94	223	8	-21			
	2013		-293	-921	1,089	133	-47	-119	1,358	-170	108	-148	-124	123	127	775	-577	-727	27	48	97	94	45			
	2014		28	-1,148	1,057	196	-29	90	1,237	-306	29	-105	110	-112	182	619	-982	-768	81	-11	246	-132	-73			
	2015		-94	-885	691	270	165	-163	1,243	-407	15	-130	-161	166	466	646	-1,330	-1,197	386	219	335	-289	-129			
Total SCHs (GWh)	2011	indicated	331	3,600	2	23,465	4,082	6,636	7,356	16,080	0	4	5,475	8,006	106	78	13,325	54	2,414	2,145	1,271	6,555	7,813	108,797	174,985	
		opposite	1,735	4,329	25,373	2	378	854	5,004	2	1,490	3,982	2,135	2,494	2,593	9,430	1,195	3,814	1,113	86	23	144	13	66,188		
	2012	indicated	313	3,647	310	21,276	6,641	13,079	2,378	15,150	1	10	5,036	15,730	12	139	17,656	122	4,168	1,511	1,200	8,145	8,419	124,943	185,180	
		opposite	2,658	4,154	17,919	5	32	1,118	11,102	40	1,534	3,719	2,577	572	2,722	8,756	141	2,988	165	17	5	13	2	60,237		
	2013	indicated	698	4,451	187	20,302	3,571	13,842	2,737	15,384	4	23	5,885	18,010	128	54	17,345	86	1,875	1,365	1,412	5,317	6,404	119,080	185,540	
		opposite	2,824	4,646	16,883	39	675	917	12,540	28	1,996	3,634	2,806	94	2,242	11,632	1,671	2,591	862	57	84	199	41	66,460		
	2014	indicated	1,177	6,146	385	21,034	4,383	16,609	3,741	19,325	4	171	3,247	18,022	163	664	21,863	300	3,205	214	224	8,459	7,144	136,480	191,532	
		opposite	2,987	4,211	17,263	30	166	62	9,674	20	1,879	3,572	3,575	47	973	7,609	487	1,734	153	64	461	57	28	55,052		
	2015	indicated	432	2,471	1,061	23,398	5,392	16,344	2,052	19,791	3	91	1,034	16,230	119	1,164	28,814	1,434	3,504	359	296	10,271	7,569	141,830	202,078	
		opposite	4,640	7,287	15,236	1	21	164	11,529	60	2,177	3,981	5,781	64	2,701	4,780	183	835	66	14	680	22	27	60,249		
Total LFs (GWh)	2011	indicated	223	166	2,468	2,978	68	80	10,116	89	185	876	78	4,009	6,404	169	492	172	427	5,548	1,013	1,733	2,058	39,353	69,730	45,1%
		opposite	1,165	4,146	275	245	2,144	4,061	0	3,982	964	1,141	4,005	79	0	2,500	3,083	1,786	452	0	199	102	51	30,378		
	2012	indicated	94	1,355	1,814	2,160	319	42	9,570	216	252	665	37	5,668	5,802	106	1,086	237	321	5,467	805	1,838	2,086	39,939	70,651	44,6%
		opposite	2,881	1,304	421	728	1,438	5,854	0	2,629	517	1,340	5,756	44	1	2,595	2,280	1,529	689	0	458	162	88	30,712		
	2013	indicated	87	1,524	1,731	1,651	352	26	8,492	486	118	1,142	21	5,245	5,924	466	757	393	112	4,983	1,019	1,436	1,645	37,609	67,790	41,7%
		opposite	2,426	1,222	502	836	1,440	5,535	9	2,013	557	1,416	5,398	30	6	2,636	2,744	1,941	998	6	141	215	110	30,181		
	2014	indicated	158	2,334	1,305	1,861	502	95	9,101	906	447	1,153	11	6,928	8,361	667	840	68	179	6,788	1,660	2,245	2,981	48,590	86,552	47,3%
		opposite	3,867	1,090	796	991	1,834	7,151	39	2,109	337	1,886	7,162	15	21	1,548	3,223	3,553	1,933	9	95	175	125	37,962		
	2015	indicated	239	1,517	3,039	1,083	251	76	9,383	1,242	632	716	76	6,095	9,141	327	692	216	86	6,781	2,439	2,296	3,441	49,768	86,974	45,4%
		opposite	1,947	1,992	187	1,488	2,391	6,426	48	1,216	82	1,833	6,318	96	0	2,208	3,382	2,634	4,786	0	61	75	34	37,205		
Total UAFs (GWh)	2011	indicated	90	36	12,729	1,188	1,141	3,445	7,832	2,907	1,283	986	3,395	319	1,741	4,264	1,839	93	868	707	1,254	689	321	47,128	84,985	54,9%
		opposite	2,892	8,943	0	2,194	784	326	110	1,056	77	1,455	319	3,398	954	106	4,905	4,688	1,210	848	290	1,288	2,015	37,857		
	2012	indicated	117	30	10,142	2,630	313	1,333	11,673	1,434	791	1,398	1,297	2,337	2,933	5,401	474	6	274	1,148	1,975	893	627	47,227	87,591	55,4%
		opposite	2,948	9,159	193	667	1,305	2,343	79	2,036	115	747	2,356	1,310	147	37	7,022	6,106	1,814	326	21	821	813	40,365		
	2013	indicated	177	67	9,708	2,189	1,086	1,831	11,990	1,232	1,007	720	1,814	2,894	2,164	6,818	1,830	94	944	1,175	1,233	1,349	999	51,320	94,774	58,3%
		opposite	2,739	8,135	171	1,020	1,497	2,875	97	2,719	63	2,020	2,898	1,813	1,053	26	6,881	6,466	706	756	388	523	607	43,454		
	2014	indicated	1,595	19	9,614	2,630	669	2,901	10,942	1,130	448	841	2,972	2,025	2,029	5,618	424	19	1,011	669	2,208	598	726	49,089	96,343	52,7%
		opposite	1,348	10,077	356	909	926	2,114	109	3,813	191	1,761	2,008	3,008	431	199	9,025	6,747	298	767	50	1,752	1,363	47,254		
	2015	indicated	1,005	341	7,457	3,085	1,763	1,359	11,199	938	283	722	1,364	2,805	4,174	5,710	246	4	3,429	2,059	2,958	219	383	51,504	104,599	54,6%
		opposite	1,832	8,095	1,400	719	315	2,784	313	4,500	153	1,859	2,772	1,347	91	48	11,893	10,487	48	143	26	2,754	1,516	53,095		

Source: Vulcanus, ACER.

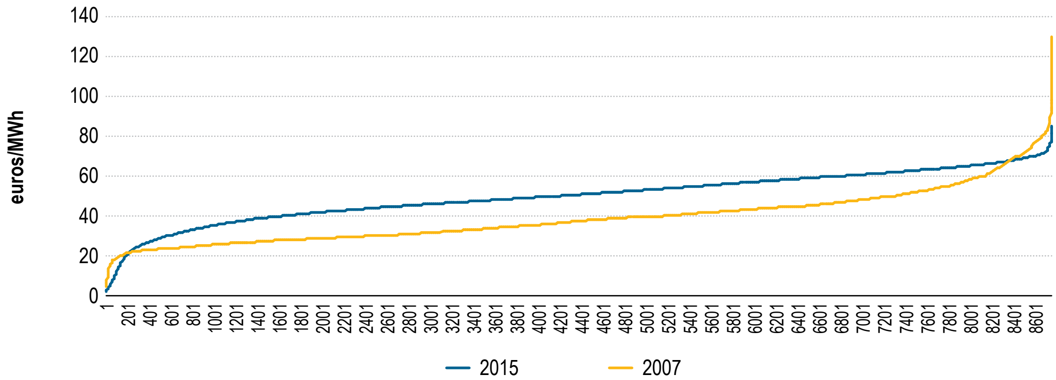
Figure 49: Percentage of hours with net DA nominations against price differentials per border – 2014–2015 (%)



Source: ENTSO-E, NRAs, Vulcanus (2016) and ACER calculations.

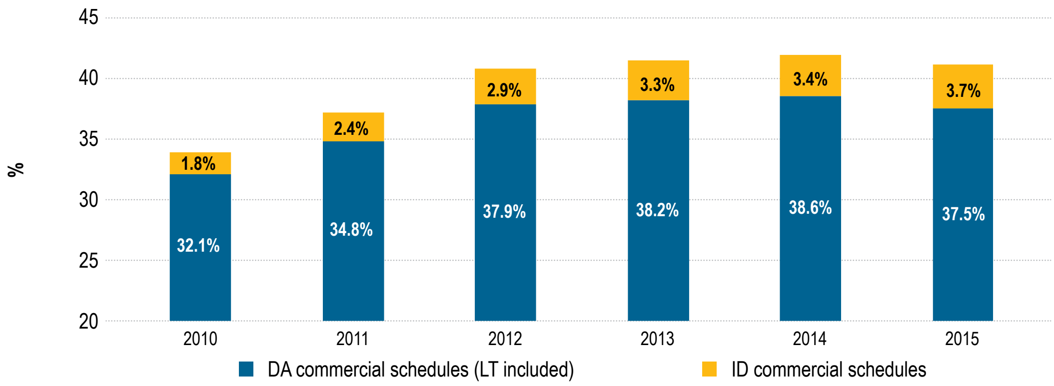
Note: Only borders with "wrong-way flows" during more than 2% of the hours of 2015 are shown in this figure. "Wrong-way flows" are not present on borders which are already coupled (those coupled before 2015 are not shown in the figure), with the exception of the Polish-Swedish borders and the French and Dutch borders with Great Britain. The borders between Poland and Sweden record a small percentage of 'wrong-way flows' when they are calculated on the basis of the most liquid DA price reference in the Polish market. The British borders with France and the Netherlands record a small percentage due to the application of a loss factor on those borders. The application of a loss factor avoids the scheduling of DA cross-border flows when the benefits from cross-border trade are below the estimated network losses that would be caused in the respective interconnectors. This prevents long-term nominations against DA price differentials from being corrected during hours of relatively small price differentials. Furthermore, IE-GB (EWIC) refers to the East-West Interconnector, which links the electricity transmission grids of Ireland and Great Britain. NI-GB (MOYLE) refers to the Moyle Interconnector, which links the electricity grids of Northern Ireland and Great Britain.

Figure 50: ID price duration curves in Spain – 2007 and 2015 (euros/MWh)



Source: EPEX and ACER calculations (2016).

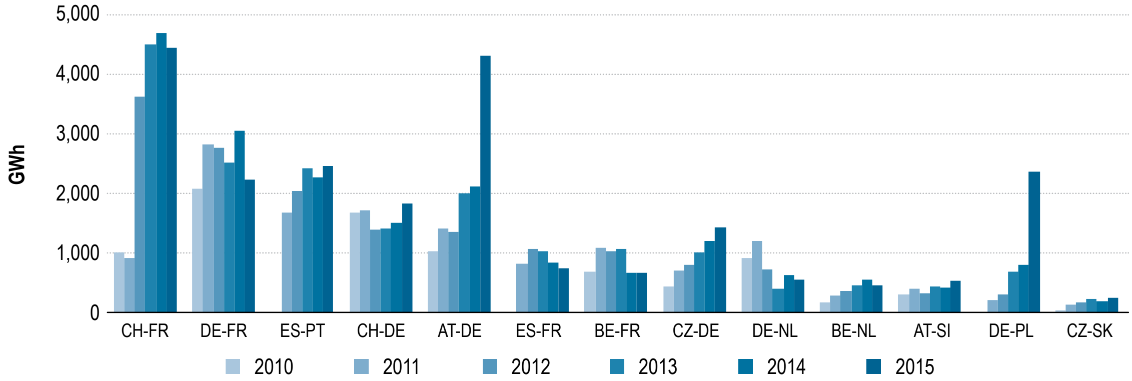
Figure 51: Evolution of the average annual level of commercial use of interconnections (DA and ID) as a percentage of NTC values for all EU borders – October 2010–2015 (%)



Source: ENTSO-E, NRAs, Vulcanus (2016) and ACER calculations.

Note: DA commercial schedules refer to all cross-border schedules resulting from LT and DA capacity allocation. ID commercial schedules refer to cross-border schedules resulting from ID capacity allocation only.

Figure 52: Level of ID cross-border trade (absolute sum of net ID nominations for a selection of EU borders) – 2010–2015 (GWh)

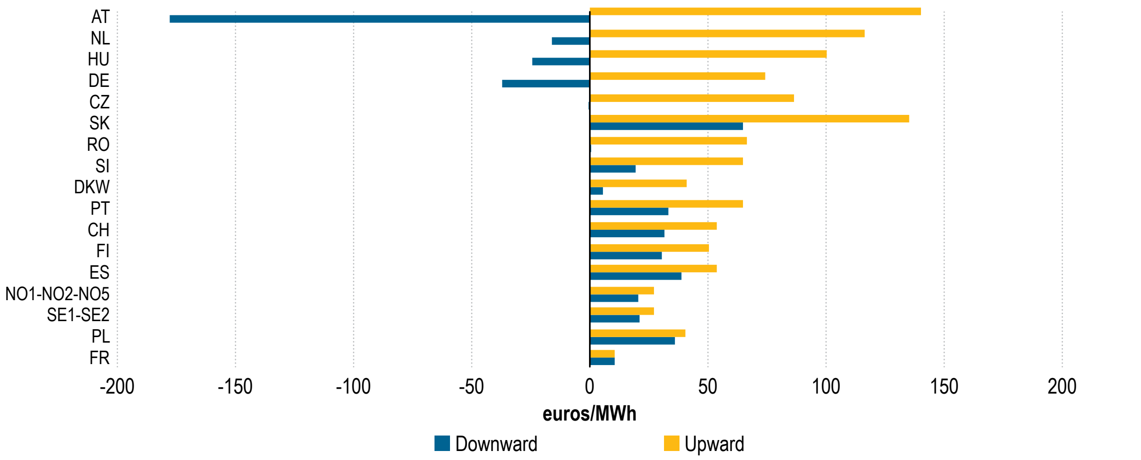


Source: ENTSO-E, NRAs, Vulcanus (2014) and ACER calculations.

Note: The reported values are the sum of the (absolute) net hourly ID cross-border schedules. As there could be trades in both directions for a specific market time unit, the reported values may be a slight underestimate of the total cross-border traded volumes in the ID timeframe. Furthermore, the figure shows only borders with aggregated net ID nominations above 200 GWh in 2015.

The volumes of ID cross-border trade that are shown in the figure also include cross-border schedules resulting from the application of remedial actions such as cross-border redispatching. This would explain the increase in the ID cross-border trade recorded on some borders (e.g. on the DE-PL border) in 2015.

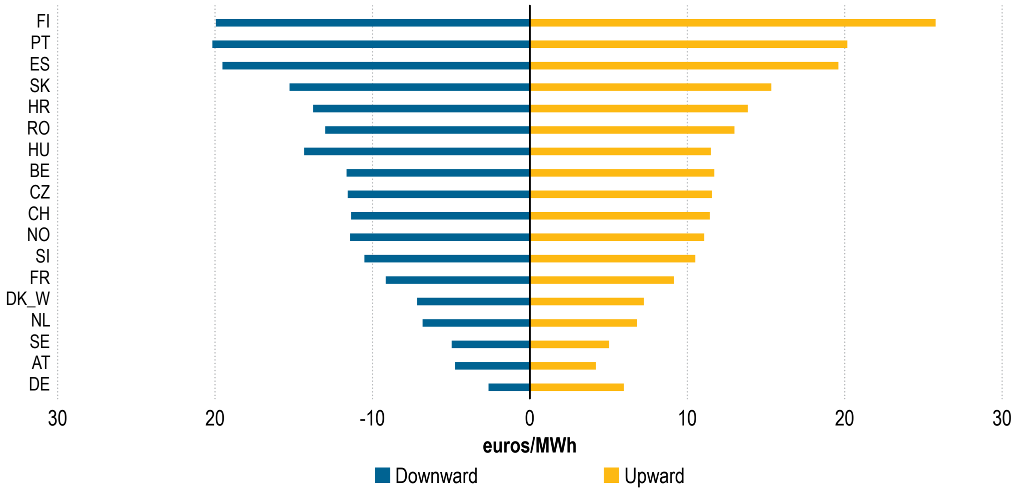
Figure 53: Weighted average prices of balancing energy activated from aFRR (upward and downward activation) in a selection of EU markets – 2015 (euros/MWh)



Source: Data provided by NRAs through the EW template (2016).

Note: For upward regulation, a positive price means that the TSO pays to the BSP for increasing its production (or reducing consumption) in one MWh and a negative price means the opposite. For downward regulation, a positive price means that the BSP pays to the TSO for reducing its production (or increasing its consumption) in one MWh and a negative price means the opposite.

Figure 54: Average prices of balancing capacity aFRR (upward and downward reserve capacity) in a selection of EU markets – 2015 (euros/MW)



Source: Data provided by NRAs through the EW template (2016).

Methodology for assessing the total transfer capacity

1. Introduction

In a zonal market design, limitations of cross-zonal capacities allocated to the market constitute a common preventive measure used by TSOs to help the system comply with the operational security standards (i.e. to ensure that the physical flows on internal and cross-zonal network elements resulting from commercial exchanges across borders do not exceed certain operational security limits).

In an efficient zonal market design (i.e. if bidding zones are properly defined), the only factor limiting trading between bidding zones should be the capacity of the network elements on the bidding zone borders (i.e. the interconnection lines).

The methodology presented below assesses the theoretical maximum transfer capacity of the bidding zone border based on the assumption of an efficient zonal market design. This theoretical maximum transfer capacity will then be used as a benchmark against which the effects of shifting internal congestion to the border are measured.

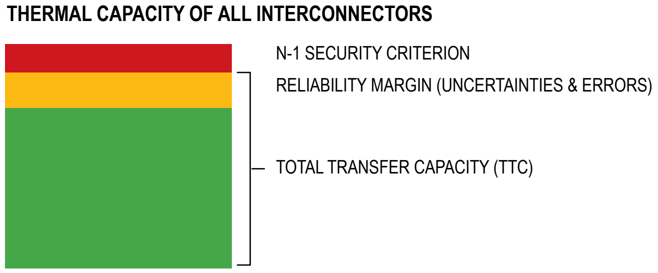
2. Thermal capacity and total transfer capacity

Disregarding uncertainties and stability concerns, the theoretical maximum exchange between two bidding zones is equal to the sum of thermal capacities of all interconnectors on the bidding zone border. However, this theoretical maximum needs to be reduced in relation to the following aspects:

a) The exchange must be feasible in contingency situations (i.e. N-1 security criterion);

b) A reliability margin needs to be preserved to account for uncertainties, due to forecasting and modelling, in the capacity calculation process.

Figure 55: Components of thermal capacity



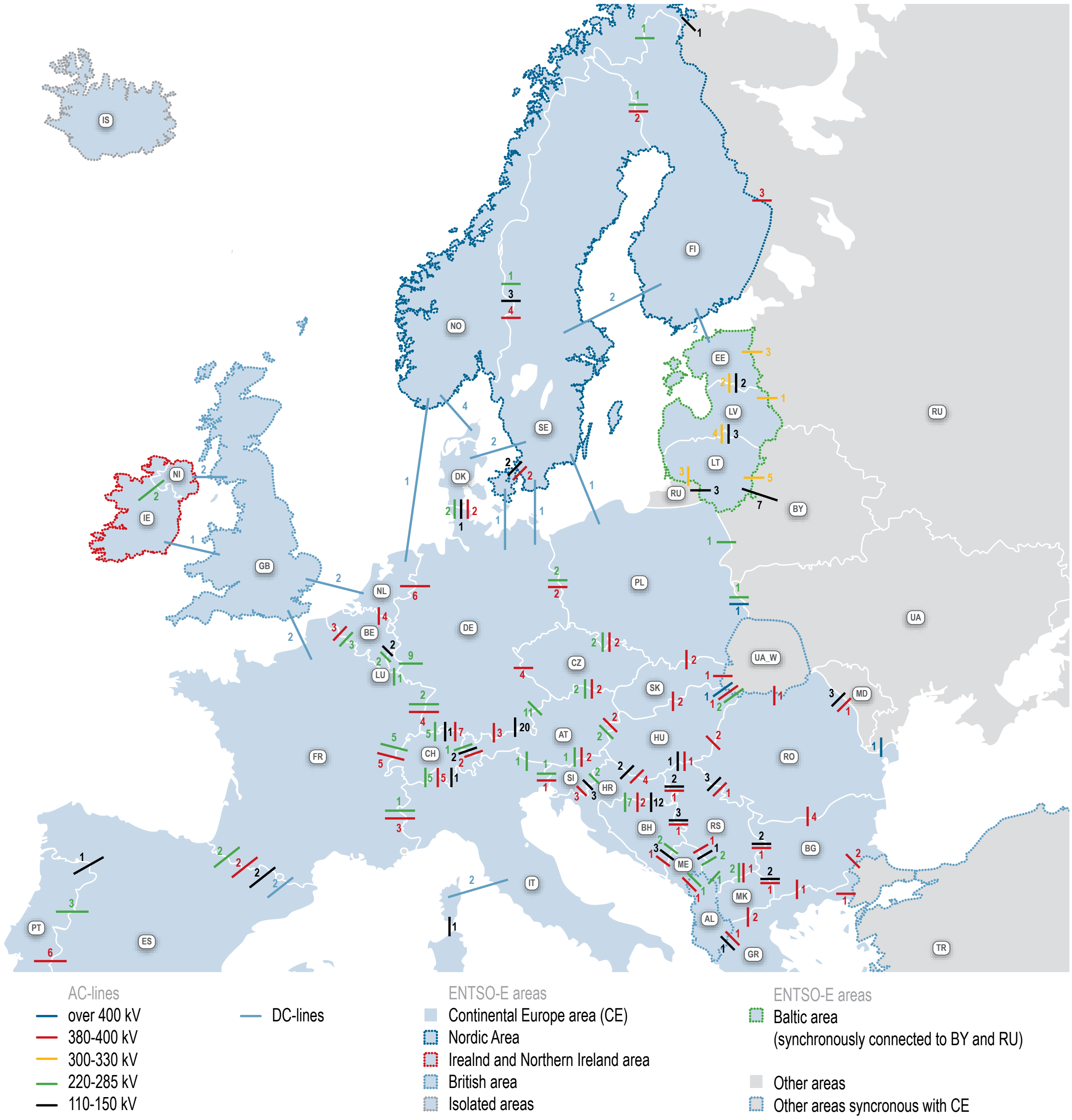
Source: ACER.

3. Methodology, data and results

Cross-zonal capacities should not be limited in order to solve congestions inside a control area. Therefore, the calculation of the N-1 operational security criterion presented below is based only on cross-border network elements and on publicly available data. A simplified diagram showing the interconnectors between MSs in the ENTSO-E area as of 31 December 2014 is presented in the figure below. The data used to produce this diagram are from the Yearly Statistics & Adequacy Retrospect (YS&AR)[113], published by ENTSO-E.

113 See: https://www.entsoe.eu/publications/statistics/yearly-statistics-and-adequacy-retrospect/Pages/default.aspx.

Figure 56: Simplified diagram of interconnectors in Europe



Source: ENTSO-E.

169 While the approach used depends on the topology of the network (meshed or not), the following assumptions apply to both types of topology:

- Only cross-border network elements are taken into account (i.e., internal network limitations are disregarded);
- A contingency event is the loss of the interconnector with the highest physical capacity or the loss of one circuit within the interconnector; and
- One single contingency in the region is considered at a time.

3.1 Meshed networks

Taking into consideration the foregoing assumptions, to calculate how much a contingency event affects the cross-border capacity in a meshed network, the following reasoning was considered:

a) In meshed networks, the physical flows on the interconnectors between two bidding zones can be significantly affected by the flows on interconnectors on other borders (i.e. interconnector connecting one of the two bidding zones to a third one). All the interconnectors that are significantly affected should be considered; therefore, the approach to calculating the N-1 criterion needs to be regionally based (i.e. when calculating the ratio between the interconnector with the highest physical capacity and the sum of the physical capacity of all significantly affected interconnectors).

b) To properly asses the exact magnitude by which an interconnector is affected in a contingency event, the Common Grid Model (CGM) and PTDFs should be used. However, currently the CGM and other tools needed for a proper analysis of the system operational security are not available to the Agency, thus the following additional simplification was used:

- Interconnectors considered as significantly affected (i.e. interconnectors that take over the load after a contingency event) are all interconnectors that are geographically located within the first two 400kV electrical circuits in each direction from the contingency event.
- The amount of loading that will be served by the each of the remaining interconnectors (i.e. after the contingency event) is proportional to its physical capacity i.e. the higher the physical capacity, the higher the loading.

c) The proposed contingency event analysis is performed for each of the two separate control areas (CTA) and takes into account all significantly affected cross-border network elements, resulting in different interconnectors being considered for each calculation. To ensure that the security criterion complies with the operational security standards for both CTAs, the more conservative value should be used.

3.1.1 Calculation of the N-1 security criterion

In the presence of a contingency event, the remaining interconnectors in service need to take over the loading of the lost network element. Therefore, the physical capacity of the interconnectors needs to be adjusted with a ratio that represents the impact of the loss of the highest-capacity network element on other significantly affected elements. This ratio equals:

$$R_{CTA\ A} = \frac{\text{Interconnector with the highest physical capacity}}{\text{Sum of physical capacity of all considered interconnectors}}$$

The ratio can be different for both CTAs, and the higher of the two should be applied when calculating the TTC:

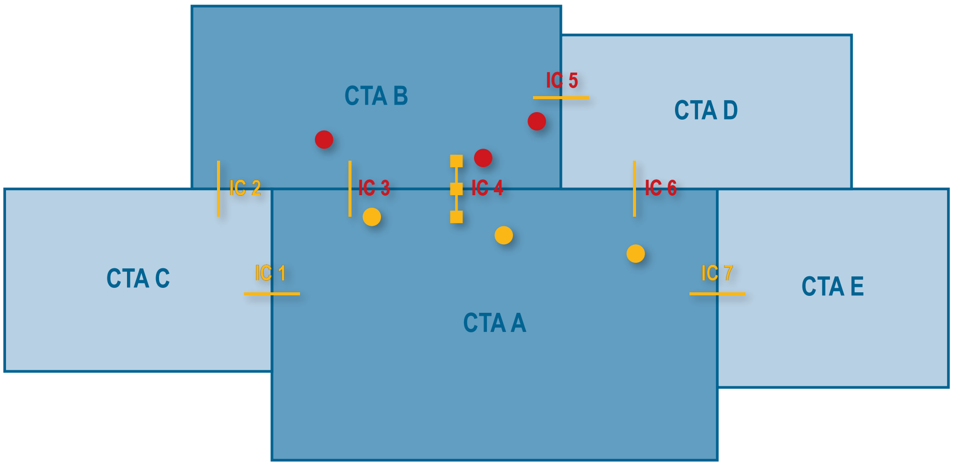
$$R_{CTA\ A,B} = 1 - Max\ (R_{CTA\ A}, R_{CTA\ B})$$

In the last step, total transferable capacity – which represents how much capacity in theory would be available for cross-border trading on the relevant border after taking into account the N-1 security criterion – is calculated as:

$$TTC_{CTA\ A,\ CTA\ B} = \text{Sum of physical capacity of interconnectors on the border} * R_{CTA\ A,B}$$

Example 1: The following figure presents a simplified example of the methodology for calculating the N-1 security criterion in meshed networks on the border between two CTA's, A and B. In this example, interconnector IC4 has suffered a fault and is unavailable.

Figure 57: Simplified example (meshed networks)



Source: ACER.

Note: In CTA A, interconnectors IC3, IC4, IC6 are considered and in CTA B, interconnectors IC3, IC4, IC5 are considered in the analysis of the contingency event (i.e. loss of IC4) on the border between CTA A and CTA B.

$$R_{CTA\ A,\ B} = 1 - Max\left(\frac{IC4}{IC3+IC4+IC6}\ ,\ \frac{IC4}{IC3+IC4+IC5}\right)$$

$$TTC_{CTA\ A,\ CTA\ B} = (IC3+IC4) * R_{CTA\ A,B}$$

3.2 Non-meshed networks

To calculate how much a contingency event, applied according to the above-mentioned assumptions affects the cross-border capacity between two countries in a non-meshed network, the following reasoning was considered:

a) Although in non-meshed networks, physical flows on the interconnectors between two bidding zones can still be affected by flows on the interconnectors on other borders (i.e. interconnector connecting one of the two bidding zones to a third one), the effect of this was not considered. Therefore, the approach to calculating N-1 criterion is based only on interconnectors between these two countries (i.e. when calculating the ratio between the capacity of the contingency event and the sum of all significantly affected interconnectors).

b) Each of the two relevant TSOs on the border perform the proposed contingency event analysis on the same network elements (i.e. interconnectors), hence the security criterion complies with the operational security standards for both TSOs.

3.2.1 Calculation of the N-1 security criterion

The ratio that represents the impact of the loss of one highest capacity network element on other significantly affected elements equals:

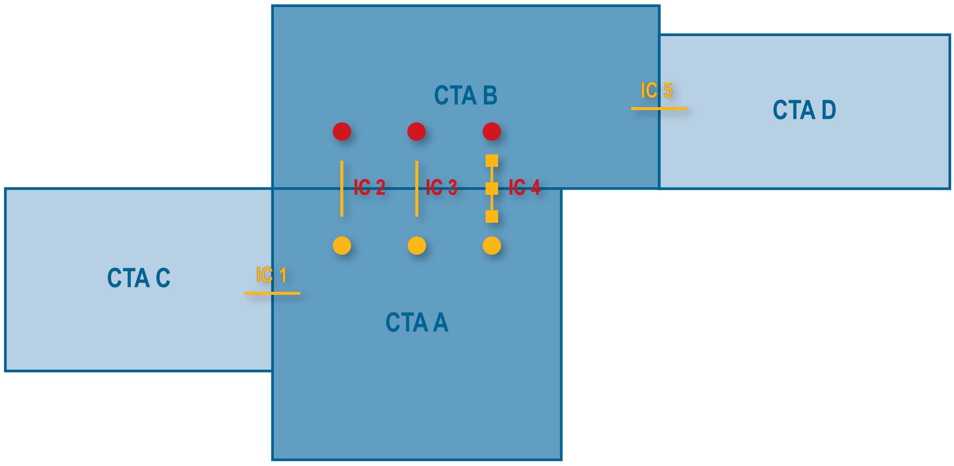
$$R_{CTA\ A} = 1 - \frac{Interconnector\ with\ the\ highest\ physical\ capacity}{Sum\ of\ physical\ capacity\ of\ all\ considered\ interconnectors}$$

In the last step, the total transfer capacity – which represents how much capacity could in theory be available for cross-border trading after taking into account the N-1 security criterion – is calculated as:

$$TTC_{CTA\ A,\ CTA\ B} = Sum\ of\ physical\ capacity\ of\ interconnectors\ on\ the\ border * R_{CTA\ A}$$

Example 2: The following figure presents a simplified example of the methodology for calculating the N-1 security criterion on the border in non-meshed networks between control area CTA A and CTA B.

Figure 58: Simplified example (non-meshed networks)



$$R_{CTA\ A,\ B} = 1 - \frac{IC4}{IC2+IC3+IC4}$$

$$TTC_{CTA\ A,\ CTA\ B} = (IC2+IC3+IC4) * R_{CTA\ A,B}$$

Source: ACER.

3.2.2 The results of applying the described methodology to European borders

Table 13: Results for meshed networks

Border	Country	Total	Sum of considered interconnectors [MVA]	Highest capacity interconnector [MVA]	Ratio	Max ratio	$R_{A,B}$	TTC [MVA]
AT-CZ	AT	7180	8,739	1,559	17.8%	17.8%	82.2%	2,973
	CZ	12017	13,576		11.5%			
AT-SI	AT	11428	12,592	1,164	9.2%	13.0%	87.0%	2,303
	SI	7762	8,926		13.0%			
DE-CZ	DE	10243	11,812	1,569	13.3%	13.3%	86.7%	4,966
	CZ	10836	12,405		12.6%			
DE-PL	DE	8204	9,506	1,302	13.7%	14.7%	85.3%	2,909
	PL	7584	8,886		14.7%			
AT-HU	AT	8266	9,780	1,514	15.5%	15.5%	84.5%	2,970
	HU	8943	10,457		14.5%			
IT-SI	IT	7363	8,982	1,619	18.0%	18.1%	81.9%	1,587
	SI	7307	8,926		18.1%			
AT-CH	AT	8856	10,186	1,330	13.1%	13.1%	86.9%	3,520
	CH	9088	10,418		12.8%			
CH-DE	DE	10260	11,867	1,607	13.5%	13.5%	86.5%	10,684
	CH	13337	14,944		10.8%			
DE-FR	DE	15936	17,726	1,790	10.1%	15.6%	84.4%	5,933
	FR	9670	11,460		15.6%			
DE-NL	DE	16323	18,021	1,698	9.4%	11.2%	88.8%	8,614
	NL	13434	15,132		11.2%			
BE-NL	BE	9412	10,888	1,476	13.6%	13.6%	86.4%	4,693
	NL	10586	12,062		12.2%			
BE-FR	BE	8276	9,579	1,303	13.6%	15.5%	84.5%	4,028
	FR	7102	8,405		15.5%			
FR-IT	FR	10788	12,032	1,244	10.3%	10.6%	89.4%	4,199
	IT	10496	11,740		10.6%			
CH-FR	CH	12826	14,378	1,552	10.8%	13.3%	86.7%	6,363
	FR	10161	11,713		13.3%			
HU-SK	SK	6990	8,432	1,442	17.1%	17.1%	82.9%	1,195
	HU	8414	9,856		14.6%			
PL-SK	SK	7180	8,432	1,252	14.8%	18.3%	81.7%	2,045
	PL	5578	6,830		18.3%			
CZ-SK	CZ	12647	14,033	1,386	9.9%	16.4%	83.6%	3,749
	SK	7046	8,432		16.4%			
CH-IT	CH	9762	11,092	1,330	12.0%	12.0%	88.0%	6,199
	IT	12606	13,936		9.5%			
CZ-PL	CZ	12099	13,187	1,088	8.3%	12.2%	87.8%	2,610
	PL	7798	8,886		12.2%			

Source: ACER.

Table 14: Results for non-meshed networks

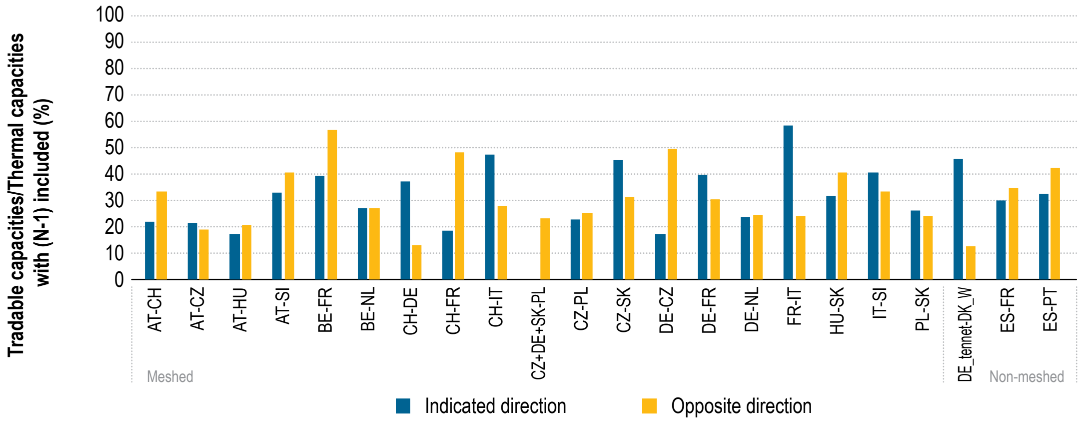
Border	Country	Total	Sum of considered interconnectors [MVA]	Highest capacity interconnector [MVA]	Ratio	Max ratio	$R_{A,B}$	TTC [MW]
ES-FR	FR	3794	5,142	1,348	26.2%	26.2%	73.8%	3,794
	ES	3794	5,142		26.2%			
ES-PT	ES	6550	8,019	1,469	18.3%	18.3%	81.7%	6,550
	PT	6550	8,019		18.3%			
DE_tennet-DK_W	DE_tennet	1.892	2,970	1,078	36.3%	36.3%	63.7%	1,892
	DK_W	1.892	2,970		36.3%			

Source: ACER.

The results show that following the proposed methodology for calculating the N-1 security criterion on borders for meshed and non-meshed networks, the TTC should on average be approximately 14% and 27% lower than the physical capacity of the interconnectors, respectively.

Figure 59 presents the ratios between available tradable capacities in 2015 and thermal capacities on the borders where the N-1 assessment was made with the above methodology. Table 15 presents the ratios with and without the N-1 assessment.

Figure 59: Ratio between available NTC and aggregated thermal capacity of interconnectors – 2015 (%)



Source: ACER.

Table 15: Ratio between available NTC and aggregated thermal capacity of interconnectors without and with N-1 assessment – 2015 (%)

Border	NTC/TC without N-1		NTC/TC with N-1	
meshed	Indicated direction	Opposite direction	Indicated direction	Opposite direction
AT-CH	19.2%	29.2%	22.1%	33.6%
AT-CZ	17.9%	15.5%	21.7%	18.9%
AT-HU	14.5%	17.7%	17.2%	20.9%
AT-SI	28.8%	35.5%	33.1%	40.8%
BE-FR	33.3%	48.0%	39.4%	56.8%
BE-NL	23.4%	23.2%	27.0%	26.9%
CH-DE	32.1%	11.4%	37.1%	13.2%
CH-FR	16.2%	41.9%	18.7%	48.3%
CH-IT	41.9%	24.4%	47.7%	27.7%
CZ+DE+SK-PL	0.0%	19.8%	0.0%	23.2%
CZ-PL	20.2%	22.1%	23.0%	25.2%
CZ-SK	37.7%	26.3%	45.1%	31.5%
DE-CZ	14.9%	42.9%	17.2%	49.5%
DE-FR	33.5%	25.6%	39.7%	30.3%
DE-NL	20.8%	21.9%	23.5%	24.6%
FR-IT	52.3%	21.7%	58.5%	24.3%
HU-SK	26.3%	33.8%	31.7%	40.8%
IT-SI	33.3%	27.5%	40.6%	33.6%
PL-SK	21.4%	19.5%	26.2%	23.9%
non-meshed				
DE_tennet-DK_W	29.1%	7.9%	45.7%	12.5%
ES-FR	22.0%	25.5%	29.8%	34.6%
ES-PT	26.8%	34.7%	32.8%	42.5%

Source: ACER.

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