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THE EU ELECTRICITY NETWORK CODES

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REPORT

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Abstract

The EU network codes and guidelines are a detailed set of rules pushing for the harmonisation of national electricity markets and regulations. A total of eight network codes and guidelines entered into force by the end of 2017: three grid connection codes, three market codes and two (system) operation codes. This text focuses on the market codes (FCA, CACM and EBGL) and their interaction with the system operation guideline (SOGI). More precisely, this text is intended to guide the reader through the sequence of electricity markets in place in the EU: forward markets, the day-ahead market, the intraday market and finally the balancing markets. First, the establishment of these different markets in a national context is discussed, then their integration. In each section basic market design concepts are explained, we highlight what is in the codes, and we also refer to some of the relevant academic literature.

Keywords: National electricity wholesale markets, Integration of national electricity wholesale markets, National electricity balancing markets, Integration of national electricity balancing markets, European regulation, Market design

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Abbreviations

4MMC: 4M Market Coupling

AC: Alternating Current

ACER: Agency for the Cooperation of Energy Regulators

aFRR: Automatic Frequency Restoration Reserve

ATC: Available Transfer Capacity

AM: Availability Margin

BM: Balancing Market

BRP: Balance Responsible Party

BSP: Balancing Service Provider

CACM: Capacity Allocation and Congestion Management Guideline

CE: Central Europe

CEP: Clean Energy Package for all Europeans

CEE: Central-East Europe

CEER: Council of European Energy Regulators

CCR: Capacity Calculation Region

CNE: Critical Network Element

CoBA: Coordinated Balancing Area

CWE: Central-West Europe

DA(M): Day-ahead (market)

DC: Direct Current

DR: Demand Response

DSO: Distribution System Operator

EBGL: Electricity Balancing guideline

ENTSO-E: European Network of Transmission System Operators for Electricity

EU: European Union

EUPHEMIA: EU Pan-European Hybrid Electricity Market Integration Algorithm

FRCE: Frequency Restoration Control Error

FB(MC): Flow-Based (Market Coupling)

FCA: Forward Capacity Allocation Guideline

FCP: Frequency Containment Process

FCR: Frequency Containment Reserve

FRP: Frequency Restoration Process

FRR: Frequency Restoration Reserve

FTR: Financial Transmission Right

GCC: Grid Control Cooperation

GCT: Gate Closure Time

HVAC: High Voltage Alternating Current

HVDC: High Voltage Direct Current

Hz: Hertz
IDA: Intraday Auction
ID(M): Intraday (market)
ISP: Imbalance Settlement Period
IEM: Internal Energy Market
IGCC: International Grid Control Cooperation
JAO: Joint Allocation Office
LFC: Load-Frequency Control
LOLP: Loss of Load Probability
MCO: Market Coupling Operator
mFRR: Manual Frequency Restoration Reserve
MO: Market Operator
MRC: Multi-Regional Coupling
MS: Member State of the EU
MTU: Market Time unit
MW: Mega Watt
MWh: Mega Watt Hour
NEMO: Nominated Electricity Market Operator
NRA: National Regulatory Agency
NRV: Net Regulated Volume
NTC: Net Transmission Capacity
ORDC: Operating Reserve Demand Curves
OTC: Over-The-Counter
PCR: Price Coupling of Regions
PTDF: Zonal Power Transfer Distribution Factor
PTR: Physical Transmission Right
RR: Replacement Reserve
RRP: Replacement Reserve Process
RSC: Regional Security Coordinators
RSCI: Regional Security Coordination Initiative
SDAC: Single Day-ahead Coupling
SEE: South-East Europe
SIDC: Single Intraday Coupling
SOGL: System Operations Guideline
TSO: Transmission System Operator
US: United States
VOLL: Value of Lost Load
vRES: variable Renewable Energy Sources (e.g. wind and solar)
XBID: Cross-Border Intraday Market Project

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1. Introduction

1.1 The network codes and guidelines

The development of network codes and guidelines has been identified as a crucial element to spur the ongoing completion of the internal energy market in the Third Energy Package. More specifically, Regulation (EC) 714/2009 sets out the areas in which network codes will be developed and a process for developing them. These codes are a detailed set of rules pushing for the harmonisation of previous more nationally oriented electricity markets and regulations. In 2017, after a 4-year-long co-creation process by ENTSO-E, ACER, the EC and many involved stakeholders from across the electricity sector, the network codes have been developed. After the development of the network codes, the implementation phase shall start.

In its Clean Energy Package (CEP), also known as the Winter Package, issued in November 2016, the European Commission proposed a recast of Regulation (EC) 714/2009, which includes provisions that would modify the operation of a number of the network codes and guidelines, in some cases quite significantly. In detail, CEP provisions attempt to alter the amendment process for existing network codes/guidelines, and the drafting process for newly introduced network codes.¹ These proposals are not covered in detail in this text.

1.1.1 Three groups of network codes

Eight network codes and guidelines came out of the co-creating process. At the time of writing, all eight have been published in the Official Journal of the European Union as European Commission implementing Regulations. Commission Regulations usually enter into force twenty days after publication, unless explicitly stated otherwise. These eight Regulations can be subdivided into three groups:

- The market codes:
 - The capacity allocation and congestion management guideline (CACM) – published on 25 July 2015
 - The forward capacity allocation guidelines (FCA) – published on 27 September 2016
 - The electricity balancing guideline (EBGL) – published on 23 November 2017
- The connection codes (CNCs):
 - The network code on requirements for grid connection of generators (RfG NC) – published on 14 April 2016
 - The demand connection network code (DCC) – published on 18 August 2016
 - The requirements for grid connection of high voltage direct current systems and direct current-connected power park modules network code (HVDC NC) – published on 8 September 2016
- The operation codes:
 - The electricity transmission system operation guideline (SOGL) – published on 25 August 2017
 - The electricity emergency and restoration network code (ER NC) – published on 24 November 2017

¹ For more details on the development and amendment process of network codes as proposed in CEP, please consult a recording of the FSR online debate on this topic:
<https://www.youtube.com/watch?v=rjtX0RXc83Y&t=2533s>

1.1.2 Network codes vs guidelines

The eight Commission Regulations in which common rules for the electricity system and market are described, often referred to as 'The network codes', are actually not all network codes by definition. Four out of eight are guidelines (CACM, FCA, EBGL and SOGL) and the other four are network codes (ER, RfG NC, DCC and HVDC NC). All texts were initially planned to be network codes, and some became guidelines in the development process. Below similarities and differences between network codes and guidelines are listed.

Similarities:

- Both carry the same legal weight (both are Commission Regulations and are legally binding)
- Both are directly applicable – i.e. there is no requirement to transpose them into local law
- Both are subject to the same adoption procedure (Comitology procedure)

Differences:

- Legal basis (Art. 6 for network codes & Art. 18 for guidelines of Regulation (EC) 714/2009)
- Amendment process (Art. 7 for network codes & Art. 18(5) for guidelines of Regulation (EC) 714/2009)
- Topics²
- Work to be done in the implementation phase

A significant difference is that guidelines include processes whereby a TSO or, in the majority of cases, a set of TSOs at Pan-European or Regional level must develop a methodology. Usually, a public consultation is held before the methodology is submitted to the relevant national regulatory authorities (NRAs) to allow for stakeholder involvement. The relevant NRAs can approve, ask to amend or reject the methodology. If the NRAs do not reach an internal agreement on whether to approve the methodology, the decision is handed over to the Agency for the Cooperation of Energy Regulators (ACER) as described in Article 8 of Regulation (EC) 713/2009.³ Network codes do not have such processes – the implementation process can proceed locally or regionally without further methodological development.

On the one hand, it can be argued that the amendment of the network codes ensures stronger stakeholder involvement, while guidelines (the primary text), at least as described by the Third Energy Package, can be amended by the European Commission via comitology without direct involvement of ACER, ENTSO-E or any other stakeholder. On the other hand, by having methodologies described in the guidelines more flexibility is allowed. Namely, in this way the detailed rules governing markets and the operation of the system can be updated in a faster way than through amendments to the primary text of the guideline itself. Flexibility can prove helpful as the methodologies could be subject to change

² Guidelines and network codes can cover the same topics (Art. 18, Reg. 714/2009), however from practice it is observed that some topics lend themselves better to guidelines than to network codes and vice-versa.

³ For a deeper discussion on ACER's decision powers regarding the approval of methodologies please see 'Exploring ACER's decision-making powers' by P. Willis posted on 24/08/17, link: <https://www.twobirds.com/en/news/articles/2017/global/exploring-acers-decision-making-powers>

as the sector evolves rapidly. Also, during the development phase of the methodologies, stakeholder involvement is (in most cases) facilitated by means of a public consultation.

In general, network codes are more detailed, while guidelines shift more tasks to the implementation phase. As mentioned above, shifting tasks to the implementation phase can allow for more flexibility, but might also slow down or complicate the overall process. There is also a risk that with guidelines, due to the requirement to develop methodologies, overlaps between different deadlines are generated. More precisely, there are local and regional compliance requirements (e.g. regional outage coordination (SOGL, Article 98(3) and Article 100(4.b))) with predetermined deadlines which rely on methodologies (e.g. methods for calculating the influence of an asset on the system (SOGL, Art. 75(1.a))) of which the date of finalisation is uncertain. The implementation processes of these local and regional requirements can be challenging when they may need to commence before the finalisation of the methodologies on which their implementation depends.

In Figure 1 the status of the implementation of the network codes and guidelines as it was in May 2017 is depicted. It can be seen that in the implementation phase, next to TSOs developing methodologies at a Pan-European or Regional level, ENTSO-E also has several tasks. These tasks are mostly related to monitoring, stakeholder involvement and reporting.

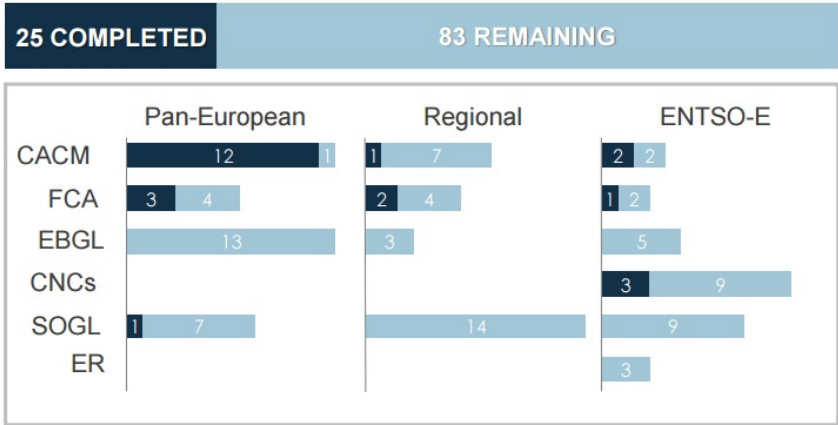


Figure 1: Status of the implementation phase of the network codes in May 2017 (ENTSO-E, 2017a)

1.1.3 Focus of this report

This report focuses on electricity markets in the EU and their integration. There is no single electricity market in place, but rather a sequence of markets as explained later in this introduction. The network codes and guidelines aim at harmonising these different markets to allow for integration. As described in Jamasb and Pollitt (2005), efficiency gains can be realised through market integration and trade as by integrating markets better use can be made of the resource diversity in the EU and across national markets. Also, by integrating markets more competition in the generation of electricity is introduced. The fundamentals of the electricity markets are described in the report and interactions with network codes and guidelines are highlighted.⁴ The most relevant network codes when talking about electricity markets are the market codes (CACM, FCA and EBGL). However, also the SOGL is of importance, as markets and system operation cannot be decoupled.

⁴ This report treats above all the text of the guidelines. The technical details of the methodologies, described in the guidelines and for which in most cases the development is ongoing, are generally out of scope.

1.2 Why do we have so many electricity markets?

Electricity can be considered as a commodity, just as copper, oil and grain are.⁵ However, electricity markets do differ substantially from markets for copper, oil and grain. The underlying reason for these differences are the physical characteristics of electricity:⁶

- *Time*: large volumes of electricity cannot be stored economically (yet). Therefore, electricity has a different cost and value over time.
- *Location*: electricity flows cannot be controlled easily and efficiently, and transmission components must be operated under safe flow limits.⁷ If not, there is a risk of cascading failures and black-outs. Therefore, electricity has a different cost and value over space.
- *Flexibility*: demand can vary sharply over time, while some power stations can only change output slowly and can take many hours to start up. Also, power stations can fail suddenly. Demand and generation must match each other continuously, if not there is a risk of black-out. Therefore, the ability to change the generation/consumption of electricity at short notice has a value.

These three unique physical characteristics can explain why there is not just one electricity market. Electricity is not only energy in MWh. Transmission capacity and flexibility are scarce resources and should be priced accordingly.⁸ Therefore, electricity (energy, transmission capacity, flexibility) is exchanged in several markets until the delivery in real-time.

1.3 Electricity market sequence

Different markets allow the pricing of the ‘invisible’ components of electricity and function as a sequence. In Figure 2 the successive markets along the three electricity components are shown. Additionally, the relevant guidelines are displayed per market. It should be noted that next to trading through organised electricity markets (exchanges), energy can also be traded bilaterally over-the-counter (OTC) – whereby market participants (electricity generators, retailers, large consumers, and other financial intermediaries) agree on a trade contract by directly interacting with each other. In this text, electricity exchanges are the focus. Unlike bilateral contracts, products on exchanges are tradable, implying transparent prices.

⁵ Two characteristics distinguish commodities from other goods such as watches, phones and clothes. First, it is a good that is usually produced and/or sold by many companies. Second, it is uniform in quality between companies that produce and sell it.

⁶ Electricity is not only unique due to its physical characteristics. It can be considered an essential good with relatively (at least until very recently) inelastic end-consumers. This is one of the reasons why, even after the liberalisation of the electricity sector, national regulatory authorities specifically mandated for electricity were established. For a more complete overview of why and how to apply electricity regulation please consult e.g. Chapter 3 in Pérez-Arriaga (2013).

⁷ This is true for alternative current (AC) power lines. Today, the meshed onshore grid in continental Europe consists mainly of AC lines. Direct Current (DC) power lines are more controllable. For a technical discussion on AC and DC lines, please consult Van Hertem and Ghandhari (2010).

⁸ In this text we focus on transmission capacity when describing the workings of EU wholesale electricity markets. At the time of writing, wholesale electricity markets interact mainly with the transmission system as discussed throughout this text. The interaction between EU wholesale electricity markets and distribution systems is limited. However, it is expected that in the near future the focus will be enlarged with more resources connected to the distribution system participating in the wholesale electricity markets.

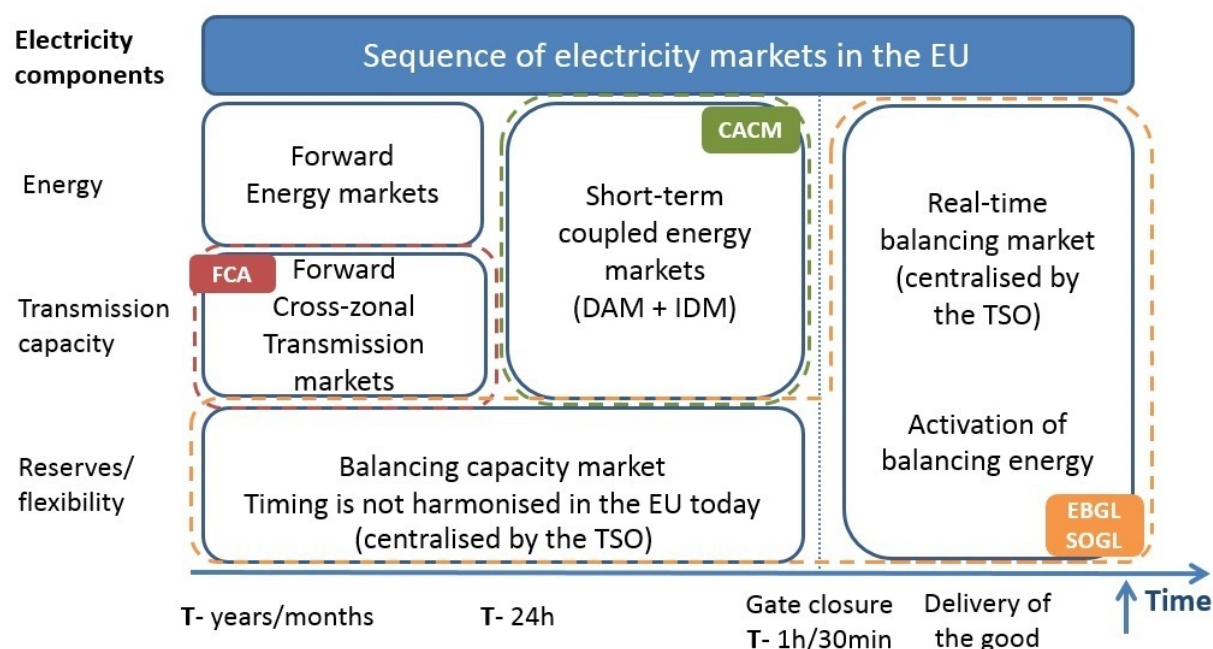


Figure 2: The sequence of electricity markets in the EU and related network codes and guidelines (Adapted from FSR (2014))

Trading of electricity, with physical delivery or purely financially, can start many years ahead in forward markets.⁹ These markets can continue until one day before delivery. The primary purpose of these long-term markets is to allow hedging for producers and consumers. Long-term cross-zonal transmission rights are traded separately from long-term contracts for energy through auctions. Transmission rights allow for hedging of price differences between bidding zones.¹⁰ Long-term cross-zonal transmission capacity markets are the focus of the FCA guidelines and are described in more detail in Chapter 3 of this report. Both physical and financial long-term transmission rights are discussed.

Closer to delivery, electricity is traded in short-term markets. Generally, it is accepted that short-term markets are comprised of the day-ahead market, intraday markets and the (near) real-time balancing market. The day-ahead market, as the name indicates, is an auction held the day before the delivery of electricity. Market participants that have not yet committed their electricity supply or demand through bilateral contracts submit their bids to the market operator (MO). The MO, described in more detail in Section 4.1, clears the auction and obtains the preliminary schedule results for the day after. The working and main characteristics of day-ahead markets are described in Section 4.2. At the time of writing, in most cases in the EU, transmission capacity is allocated jointly (implicitly) with energy in the day-ahead market. This process is called market coupling. The integration of the day-ahead market is the focus of Section 5.1.

⁹ In the financial literature, long-term markets with standardised products are called ‘futures markets’, while long-term markets with unstandardized products are called ‘forward markets’. In this report, we use the term ‘forward markets’, however a distinction is made between trading in exchanges (standardised) and trading over-the-counter (unstandardized). The focus in this text is on trading through exchanges.

¹⁰ Bidding zones are explained in the Section 2.1. A bidding zones is defined as the largest geographical area within which market participants can exchange energy without capacity allocation.

After the day-ahead market, producers and consumers have the possibility to change their positions through intraday markets. Intraday markets are organised as continuous markets, with possible complementing auctions. Intraday markets and their integration are described in detail in Section 4.3 and Section 5.2, respectively. The design rules and the ways to integrate day-ahead markets and intraday markets are outlined in the CACM guideline. Intraday trading is possible until a moment in time called the intraday gate closure time (GCT). After the GCT, the final production schedule is determined for all participants, and only the Transmission System Operator (TSO) can act to adjust any deviation. The mechanism used to ensure that supply equals demand in real-time is called the balancing mechanism.

The balancing mechanism is supported by two balancing markets. The first is a balancing market for capacity. This market takes place from one year up to one day before real-time, the exact timing is not harmonised in the EU at present. Generators or demand are contracted to be available to deliver balancing energy in real-time. Second, there is a balancing market for energy. In this market the participating generators or demand indicate the price they want to receive to increase or decrease their energy injection or withdrawal in real-time. These bids/offers are supposed to have been submitted before the balancing energy gate closure. Generators/demand contracted in the balancing capacity market are obliged to participate in the balancing energy market.¹¹ In real-time, the TSO activates the least-cost resources with the requested technical capabilities to fix imbalances between generation and consumption. The balancing mechanism is the focus of the EBGL. Also, the SOGL is important for this market segment as more details on the types of reserves, their sizing and the roles and responsibilities for ensuring real-time balance are described in that guideline. The balancing mechanism and its integration are the topics of Chapters 6 and 7, respectively. In some cases, the balancing mechanism is also used as the means of procuring some non-frequency ancillary services, such as reactive power.¹² This aspect of the balancing mechanism is not discussed further here.

¹¹ It is not necessary, in some Member States at least, to participate in the balancing market for capacity in order to participate in the balancing market for energy.

¹² For example: Ireland and Northern Ireland, for more information see chapter 8.3 of https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-15-026%20I-SEM%20ETA%20Markets%20Consultation%20Paper_0.pdf

2. The link between markets and grids in the EU: key concepts

Before starting the chapters describing the different electricity markets and their integration, key concepts relevant to how electricity markets and physical grids are interlinked in the EU context are illustrated. As mentioned in the introduction, electricity transmission capacity is scarce. An important market design question that needs to be answered is how to deal with the complex physical reality of the grid when trading electrical energy. To tackle this question, this chapter is split into three Sections.

- The first Section focuses on the important concept of bidding zones. In the same Section, zonal pricing and the difference between bidding zones and control areas is explained.
- The second Section introduces the concept of capacity calculation regions. It describes the way interdependent cross-zonal transmission capacity calculation is organised. The focus is on the governance framework; the (more technical) methodologies for calculating the transmission capacities are explained in Subsection 5.1.2. Further, the link between capacity calculation regions and regional security coordinators is explained.
- The third Section introduces denotations of geographical areas relevant for balancing and system operation and links these areas back to bidding zones and control areas described in the first Section of this chapter.

2.1 Local: Bidding Zones (market) and Control Areas (grid)

How can electrical energy trading and network flows be matched? The chosen approach to this problem applied in the EU today is called zonal pricing. Zonal pricing means that wholesale electricity prices can differ between zones in Europe, so-called bidding zones, but are homogeneous within a particular zone. From the market perspective, the network within a bidding zone is a copper plate – physical capacity is treated as infinite.

Different bidding zones are electrically connected by cross-zonal interconnectors. If a cross-zonal connector between two bidding zones is not fully utilised (no congestion), the wholesale electricity prices of the two zones converge for that period. The markets are fully coupled. However, when the cross-zonal interconnectors are congested, the prices between the two bidding zones can diverge for that period. The markets of the two bidding zones are in that case split. The price differential between the two bidding zones is called the congestion rent, and this is a revenue for the TSOs owning the interconnection.¹³

It can happen that the outcome of the market, also called the ‘nominations’ of producers and consumers, results in unfeasible network flows within a bidding zone. In that case, the TSO, operating the part of the network within the bidding zone where the problem occurs will have to take remedial actions. According to the terminology applied by ACER and Council of European Energy Regulators (CEER), there are different types of remedial actions. Changing grid topology is a preventive remedial

¹³ For example, imagine that during a certain hour the interconnectors between two bidding zones are congested. The price in one bidding zone equals 30 €/MWh and 40 €/MWh in the other. The interconnection capacity between the two bidding zones is 500 MW. This means that the congestion rent equals in this hour 5,000 €. Please note that in some cases a transmission line can also be owned by a private party other than a TSO. For more information on ‘market-driven’ merchant transmission investment please consult e.g. Joskow and Tirole (2005).

measure that does not result in significant costs for the TSO. Conversely, redispatching, counter-trading and the curtailment of already allocated capacity are curative and costly measures (ACER and CEER, 2016). These concepts are further developed in Section 4.4.

Bidding zone configurations are reviewed periodically and, once defined for a certain period, are constant throughout all market time frames (long-term, day-ahead, intraday and real-time). The criteria for reviewing bidding zones are outlined in Art. 33 of the CACM.¹⁴ Because of historical reasons, bidding zones in Europe are very similar to country borders. In Figure 3 (left) the bidding zone configuration as it is in 2017 is shown.¹⁵

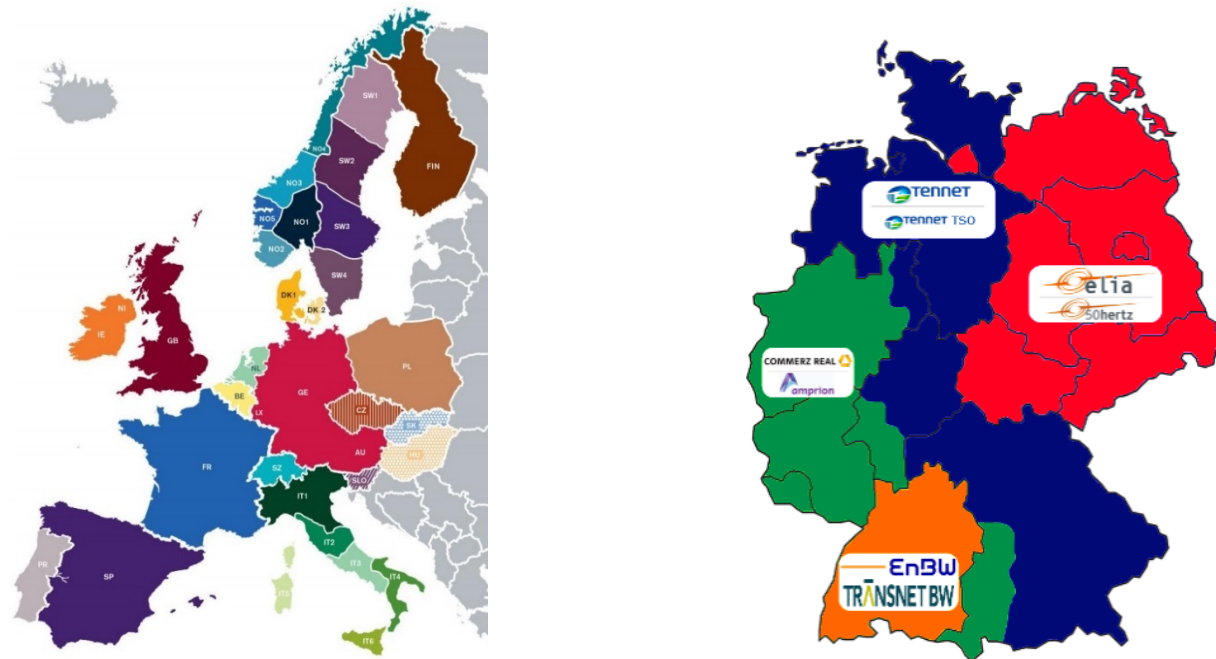


Figure 3: Left – Bidding zones in 2017 (Ofgem, 2014). Right – Control areas in Germany (Wikiwand, 2017)

Two concepts which can be easily confused are bidding zones and control areas. A control area is defined as a coherent part of the interconnected system, operated by a single system operator. The system operator is responsible for maintaining the operational security of its control area. In Europe, the TSO is the entity which operates the transmission system and manages and owns the transmission assets.¹⁶

In most cases, though not all, the control area matches the bidding area. For example, the Belgian territory is covered by one control area and one bidding zone. The transmission network is owned and operated by one TSO, Elia. There are also countries with more control areas than bidding zones. An example is Germany. The German territory is divided into four control areas, as shown in Figure 3

¹⁴ Enumerated criteria for reviewing bidding zones are: (a) network security, (b) overall market efficiency, (c) stability and robustness of bidding zones

¹⁵ A bidding zone review study is being carried out by ENTSO-E. The official deadline for this report is March 2018.

¹⁶ In the Americas the transmission system is not necessarily operated by the same entity that manages and owns the transmission assets. For a discussion on this matter please see e.g. Chawla and Pollitt (2013).

(right). The country is covered by one bidding zone (together with Luxemburg and Austria).¹⁷ Lastly, there are also countries with more bidding zones than control areas. Sweden is an example of a country of which the boundaries of the control area correspond to the national borders. The Swedish TSO is Svenska Kraftnät. However, the country is split up into four bidding zones.

2.2 Regional: Capacity Calculation Regions (market) and Regional Security Coordinators (grid & market)

To ensure that cross-zonal transmission capacity calculation is reliable and that optimal capacity is made available to the market, regional coordination between the TSOs operating the bidding zone borders is required. This is true as electricity flows in a meshed network are highly interdependent due to its physical nature.

In order to make coordination happen, Art. 15 of the CACM requires Capacity Calculation Regions (CCRs) to be determined. A CCR comprises a set of bidding zone borders and is defined as the geographic area in which coordinated capacity calculation is applied. In October 2015, ENTSO-E submitted a proposal for CCRs to all regulatory authorities for approval (ENTSO-E, 2015a). This proposal is shown in Figure 4 (left). The regulatory authorities failed to reach an agreement within a predefined six-month period (CACM, Art. 9(11)). Therefore, ACER had to decide. Finally, ACER approved the proposal, under the condition of merging Central West Europe (CWE) and Central Eastern Europe (CEE) to one CORE region (ACER 2016). In the long-term, the idea is to merge more and more CCR if feasible.

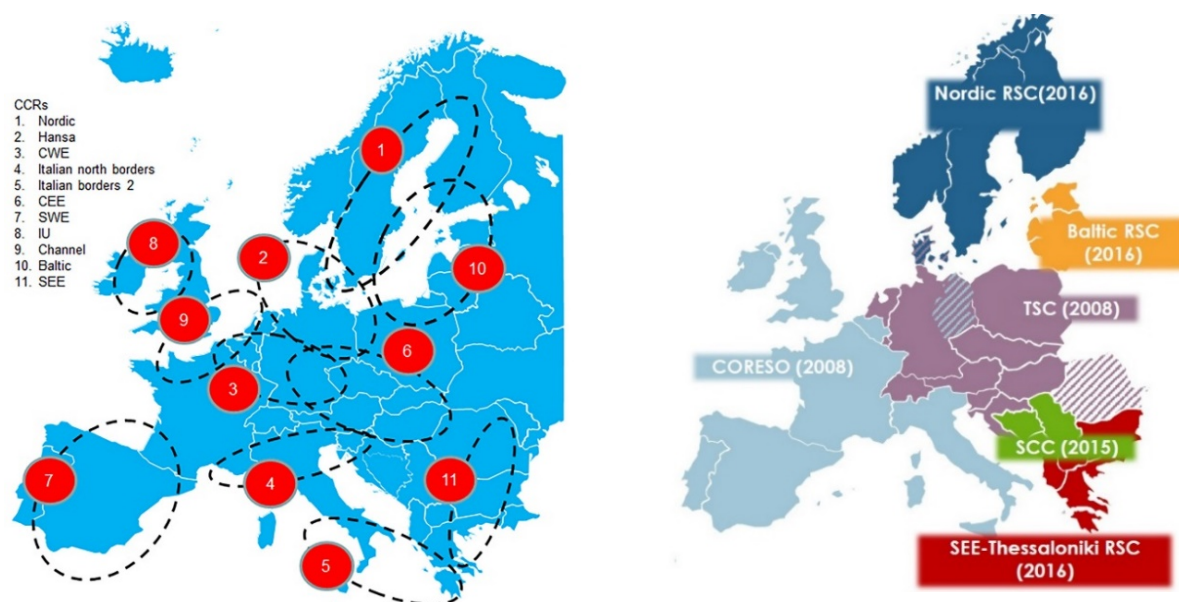


Figure 4: Left – Proposal of ENTSO-E (2015a) for the Capacity Calculation Regions (ENTSO-E, 2015b). Right – An overview of the Regional Security Coordinators in Europe (ENTSO-E, 2017a)

In the CACM it is also outlined that all the TSOs in each CCR shall jointly set up the coordinated capacity calculators and establish rules governing their operation. Coordinated capacity calculators have the task of calculating transmission capacity, at regional level or above. CCRs are of importance in all

¹⁷ At the time of writing, Germany, Austria and Luxembourg are one bidding zone. In September 2015, ACER issued a legally non-binding opinion to split the German-Austrian bidding zone (ACER, 2015e). The splitting of the German-Austrian bidding zone is now on the political agenda and could be carried out by July 2018. However, a final decision is expected after the publication of the ENTSO-E bidding zone review study.

market codes (FCA, CACM and EBGL) and in the SOGL. In short, for all time frames the capacity calculation should be done with a harmonised methodology per CCR.¹⁸ The coordinated capacity calculator should receive the necessary inputs from all concerned TSOs to perform the computation of available capacity (for long-term, day-ahead, intraday and balancing markets) at all bidding zone borders within its CCR. A crucial tool that is created for this purpose is the common grid model, of which the principles are described in a methodology following FCA (Art. 18) and CACM (Art. 17).¹⁹

Entities strongly tied with CCR are Regional Security Coordinators (RSC) whose role was established in EU law with the adoption of the SOGL. In the SOGL it is stated that each control area shall be covered by at least one RSC. RSCs are owned or controlled by TSOs and perform tasks related to TSO regional coordination (SOGL, Art. 3(89)). The predecessors of RSCs were set up as voluntary initiatives (RSCIs) by TSOs in 2008, with CORESCO (based in Brussels) and TSCNET services (Munich) as pioneers in Continental Europe. In 2015, one RSCI was created in South East Europe (SEE) in Belgrade. In 2016, the Nordic TSOs started discussing the creation of a Nordic RSCI (ENTSO-E, 2017b). (Voluntary) RSCIs will evolve into (mandatory) RSCs. An overview of the geographical coverage of RSCs as planned is shown in Figure 4 (right).

RSCs will be active in one or more CCRs and have five core tasks, mostly related to grid security (for more details, see e.g. FTI-Compass Lexecon (2016)).²⁰ An RSC issues recommendations to the TSOs of the capacity calculation region(s) for which it is appointed. TSOs should then, individually, decide whether or not to follow the recommendations of the RSC. The TSO has final responsibility for maintaining the operational security of its control area. One of the tasks of the RSCs is also coordinated capacity calculation. The link between the coordinated capacity calculators (FCA and CACM) and RSCIs (later RSCs in SOGL) is described by ENTSO-E (2014, p. 4): *‘For one Capacity Calculation Region with more than one established RSCIs, at a given point in time, one RSCI will be responsible for assuming the function of the Coordinated Capacity Calculator. Other RSCIs having responsibilities within this Coordinated Capacity Calculation Region can assume this function at any time, as a back-up option. This scheme ensures consistency between coordinated capacity calculation and coordinated security assessment.’*

2.3 Balancing Areas: in between markets and grids

In order to fully grasp the way balancing is conducted in the EU, as described in Chapter 6, some additional concepts indicating geographical areas of importance for the balancing mechanism need to be introduced. Also, links between the new balancing concepts and previously introduced bidding zones and control areas are made in this Section.

¹⁸ The ‘all time frames’ being: long-term (FCA, Art. 21(2)), day-ahead (CACM, Art. 29 and 46(1)), intraday (CACM, Art. 29 and 58(1)) and the balancing time frame for the exchange of balancing energy for operating the imbalance netting process (EBGL, Art. 37(3)) and for the allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves (EBGL, Art. 38(2)).

¹⁹ According to CACM (Article 2(2)), a common grid model is defined as a Union-wide data set agreed between various TSOs describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process.

²⁰ Additionally, in the Emergency and Restoration network code (ER NC) it is described that RSCs will be consulted to assess the consistency of measures described in a system defence and restoration plan of a TSO with the corresponding measures in the plans of TSOs within its synchronous area and in the plans of neighbouring TSOs belonging to another synchronous area (Art. 6(3)).

In Figure 5 (left) the terminology used to indicate geographical areas in the FCA/CACM (markets), EBGL (balancing) and the SOGL (system operation) are summarised. Balancing is done by means of a market-based process in the EU. However, it cannot be fully decoupled from system operation as this process takes place very near or in real-time. Therefore, geographical concepts in the EBGL can be more market-related or more system operation-related, depending on which part of the balancing code is considered. As depicted in Figure 5 (left), the largest geographical area is the Internal Energy Market (IEM) in the EU and the smallest building block is a scheduling area.

The IEM is split up into different synchronous areas, as shown in Figure 5 (right), and defined as ‘*areas covered by synchronously interconnected TSOs, such as the synchronous areas of Continental Europe, Great Britain, Ireland-Northern Ireland and Nordic and the power systems of Lithuania, Latvia and Estonia, together referred to as ‘Baltic’ which are part of a wider synchronous area.*’ (RfG NC, Art. 2(2)) Synchronous areas are mainly important for the fastest types of reserves; these are dimensioned and operated at this scale as further discussed in Section 6.1.²¹ The different types of reserves are described in the introduction to Chapter 6.

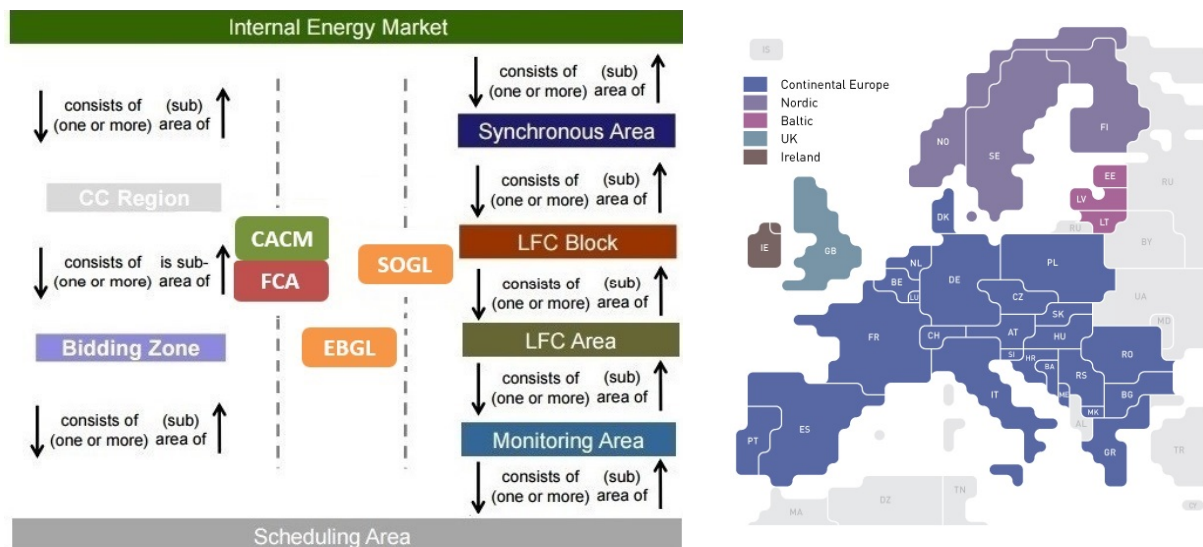


Figure 5: Left – FCA/CACM (markets) vs EBGL (balancing) vs SOGL (system operation) terminology to denote geographical areas (adapted from ENTSO-E, 2014b). Right – the different synchronous areas in Europe (ENTSO-E, 2017l).

Also, the notion of a Load-Frequency Control (LFC) Block is important as this is the geographical area over which reserves (other than the fastest type) ought to be dimensioned by the SOGL. The SOGL (Art. 3(18)) defines an LFC Block as ‘*a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC blocks, consisting of one or more LFC areas, operated by one or more TSOs fulfilling the obligations of load-frequency control*’. A proposal regarding the determination of the LFC Blocks will be done by all TSOs of a synchronous area 4 months after the entry into force of the SOGL (SOGL, Art. 141(2)).

²¹ The main task of the fastest type of reserves (Frequency Containment reserves) is to dampen/stop a sudden drop or rise in system frequency.

The frequency restoration process is (jointly) operated by the TSO(s) of a Load-Frequency Control (LFC) Area (SOGL, Art. 141(4)(b)).²² In the SOGL (Art. 3(12)) an LFC Area is defined as *'a part of a synchronous area or an entire synchronous area, physically demarcated by points of measurement at interconnectors to other LFC Areas, operated by one or more TSOs fulfilling the obligations of load-frequency control.'* A Monitoring Area is defined in SOGL (Art. 3(145)) as *'a part of the synchronous area or the entire synchronous area, physically demarcated by points of measurement at interconnectors to other monitoring areas, operated by one or more TSOs fulfilling the obligations of a monitoring area'*. The real-time active power interchange of the monitoring area is constantly tracked by all TSOs in each monitoring area (SOGL, Art. 141(3)). In most cases, the LFC Area is equal to the Monitoring Area and to the TSOs' Control Area (ENTSO-E, 2014b).

Finally, a Scheduling Area is considered the smallest building block for system operation. It is equal to one or more Control Areas, but can never be bigger than a Bidding Zone. More precisely (SOGL, Art. 110(2)):

- Where a bidding zone covers only one control area (e.g. Belgium), the geographical scope of the scheduling area is equal to the bidding zone.
- Where a control area covers several bidding zones (e.g. Sweden), the geographical scope of the scheduling area is equal to the bidding zone.
- Finally, where a bidding zone covers several control areas (e.g. Germany), TSOs within that bidding zone may jointly decide to operate a common scheduling process. Otherwise, each control area within that bidding zone is considered a separate scheduling area.

The notion of Scheduling Area is important because important actions related to the balancing mechanism are done at the level of the scheduling area, i.e.:

- Contractual positions by Balance Responsible Parties (BRPs) are communicated to the TSO of the scheduling area (SOGL, Art. 111(1))
- The measurement of the 'system' imbalance is done per scheduling area (EBGL, Art. 54(2))
- The Balancing Service Providers (BSPs) participating in the balancing capacity or balancing energy market belong to the same scheduling area (EBGL, Art. 16(8))²³

²² This process is operated at LFC area scale but is well-coordinated with the synchronous area. The frequency restoration process can be described as the process in which reserves are activated to release FCR activated at synchronous area scale and to restore the frequency back to the nominal value if imbalances between generation and consumption occur in real time. In more technical terms, the frequency restoration control error (FRCE) is regulated towards zero.

²³ The integration of balancing capacity and energy markets between scheduling areas is the focus of Chapter 7.

3. Forward markets

Trading of electricity, with physical delivery or purely financially, can start many years ahead in forward markets. These markets can continue until one day before delivery. Competitive and liquid forward markets are essential for market participants to hedge their short-term price risks. Prices in shorter-term electricity markets can fluctuate, e.g. due to high/low renewable energy infeed. Also, well-functioning short-term markets can deliver sharp scarcity prices. These scarcity prices are crucial to signal the need for flexibility at a particular time and place and to incentivise new investment (adequacy) in the longer run. However, not all producers want their business case to be dependent on hard-to-forecast fluctuating prices and occasional price spikes. Also, large consumers or retailers might want to stabilise their expenditure. Therefore, there is a demand for forward markets with long-term contracts for electricity supply. Newbery (2016) states that *'a lack of forward markets and long-term contracts might not be so critical if the future were reasonably predictable and stable, but that this is far from the case at present.'* Also Genoese et al. (2016) and Neuhoff et al. (2016) argue that the provision of long-term price signals will become (even) more important in the future, one important argument is that long-term contracts can reduce the cost of capital of renewables and flexible generation, characterised by high upfront investment costs.

The integration of forward energy markets is crucial to allow a more efficient functioning and higher degrees of necessary liquidity. Therefore, long-term cross-zonal transmission rights are auctioned. By acquiring these rights, market participants can trade cross-zonal in forward markets. Without these rights, the risk related to price differentials between different bidding zones can significantly reduce the appeal of such cross-zonal trades. Also, cross-zonal transmission rights are of importance to be able to hedge risk across different time frames within a certain bidding zone. This would be the case when there is limited variation in the duration of long-term electricity contracts in a given bidding zone, while in another bidding zone (a so-called hub) a greater range of contracts with many different durations are offered.

First, forward energy markets are introduced in this chapter. After the integration of forward markets is discussed, the implications of the FCA guideline are highlighted.

3.1 Forward energy markets

Long-term electricity contracts can be traded on unstandardised forward and standardised future markets. The design of the (national) forward electricity markets is not covered by the network codes. Instead, the allocation of long-term cross-zonal transmission rights are the focus of the FCA. Long-term cross-zonal transmission rights are needed to allow the integration of these forward markets. Integration can help these markets function more efficiently.

The analysis in ACER and CEER (2016) shows that, in general, the liquidity of forward markets in Europe remained low in 2015, except for Germany, the Nordics, France and GB. In Figure 6, the churn ratio for the most relevant European countries is shown.

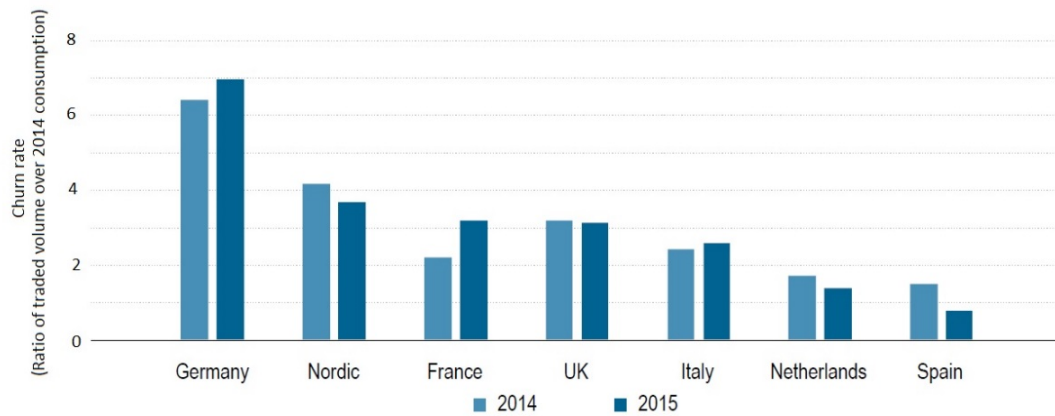


Figure 6: Ratio of traded volume in forward markets over 2014 consumption (ACER and CEER, 2016)

The churn ratio is a way to measure liquidity and is defined as the volumes traded expressed as a multiple of physical consumption. A churn factor of three could be considered to be a minimum value (ACER and CEER, 2016). Very few countries reach that threshold. It is also interesting to note that liquidity decreases with increasing forward periods (Genoese et al., 2016).

3.2 Integration of forward markets: long-term (cross-zonal) transmission (capacity) rights

Long-term transmission rights are a necessary tool to allow for a further integration of electricity markets. In the recent past, multiple sets of rules were in place to regulate long-term cross-zonal transmission capacity trade among Member States (MS) (Rakhmah and Yanfei, 2016). ACER and CEER (2016) describe that in 2015 the persistence of high absolute values of assessed risk premium in the valuation of transmission rights point to different problems in the markets for these products.²⁴

The goal of the FCA guideline is to foster the trade in long-term cross-zonal transmission capacity rights. With FCA in force, TSOs are obliged to issue long-term transmission rights on a bidding zone border unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border. When adopting their decisions, the competent regulatory authorities of the bidding zone border are required to consult the regulatory authorities of the relevant capacity calculation region and take due account of their opinions. (FCA, Article 30(1)). All TSOs issuing long-term transmission rights shall offer long-term cross-zonal capacity to market participants for at least annual and monthly time frames (FCA, Article 31(2)). The allocation of long-term cross-zonal transmission capacity is conducted through explicit auctions. Explicit auctions mean that transmission capacity and electricity trading are auctioned separately.

This section is split up into four subsections describing key components of the market in long-term cross-zonal transmission capacity rights. Please note that this description is not necessarily exhaustive.

²⁴ 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 (ACER and CEER, 2016).

3.2.1 Allocation: Harmonised rules and a single European platform

Different rules for different borders did not allow for efficient cross-zonal trade of long-term electricity supply. The goal of the FCA guideline is to harmonise the existing multiple allocation rules at the European level.

A first step in that direction is to introduce harmonised allocation rules (HAR) for long-term transmission rights. According to the FCA, all TSOs had to submit a proposal for these rules 6 months after the entry into force of the Regulation (FCA, Art. 51(1)) covering several aspects in the forward capacity allocation (FCA, Art. 52), inter alia returns and transfers of long-term transmission rights as well as firmness and curtailment compensation rules. In addition to these harmonised allocation rules, specific regional requirements or requirements for individual borders where long-term transmission rights are allocated can be proposed (FCA, Art. 51(1)). Given the importance of this task, TSOs have proposed harmonised allocation rules already before the entry into force of the FCA as part of the early implementation of the FCA. In the framework of the official implementation of the FCA, all TSOs submitted the updated proposal of the harmonised allocation rules and the specific border/regional requirements in April 2017 (ENTSO-E, 2017c). All NRAs did not reach an agreement and the decision was handed over to ACER. The proposal was finally adopted in October 2017 after minor modifications by ACER.

Moreover, a key instrument towards the integration of cross-zonal long-term markets is the setup of a single European platform for the allocation of long-term cross-zonal transmission rights. Some steps have already been taken in that direction. On 24 June 2015, the two regional allocation offices for cross-zonal electricity transmission capacities in place at that time, approved the merger agreement to create the Joint Allocation Office (JAO). The JAO is a joint service company of twenty TSOs from seventeen countries. It performs mainly the yearly, monthly and daily auctions of transmission rights on 27 borders in Europe. In their proposal for the Single Allocation Platform submitted in April 2017, all TSOs proposed JAO to be named as the Single Allocation Platform (ENTSO-E, 2017d). In September 2017 all NRAs approved this proposal.

A practical example of the importance of a single European platform and harmonised allocation rules is the timing and length of different cross-zonal transmission rights. If long-term transmission rights are not allocated simultaneously, market participants who need to 'cross' several borders cannot efficiently hedge their cross-zonal short-term price risk.

3.2.2 Calculation of future cross-zonal transmission capacity

As stated in the FCA guideline: *'Long-term capacity calculation for the year- and month-ahead market time frames should be coordinated by the TSOs at least at regional level to ensure that capacity calculation is reliable and that optimal capacity is made available to the market.'*

What 'coordination on regional level' exactly aims at are that calculations are done at the level of the Capacity Calculation Regions (CCR). Capacity Calculation Regions (CCR) are described in Section 2.2. For this purpose, TSOs should establish a common grid model gathering all the necessary data for the long-term capacity calculation and taking into account the uncertainties inherent to the long-term time frames.

Long-term capacity calculation can be done by applying two approaches: the flow-based approach and the coordinated net transmission capacity (NTC) approach. These calculation methods are explained in more detail in 5.1.2. The FCA leaves it open as to which approach should be applied, a proposal by all TSOs per CCR needs to be submitted and approved by the relevant NRAs (FCA, Art. 10). However, it is mentioned that the flow-based approach might be justified where cross-zonal capacities between bidding zones are highly interdependent.

3.2.3 Products and pricing

Two products for long-term cross-zonal transmission capacity rights are described in the FCA; definitions are taken from Batlle et al. (2014):

- Physical transmission rights (PTR): *'A PTR entitles the buyer to the right to transmit a specific amount of power between two electricity network nodes during a given period of time. In Europe, PTR holders must declare whether they intend to exercise their physical right ('nomination') before a pre-established deadline, often the day ahead. Where they fail to do so, the system operator automatically re-sells the right on the short-term market on behalf of the holder, who receives the resale price. This is known as the use-it-or-sell-it (UIOSI) condition.'*
- Financial transmission rights (FTR): *'An FTR hedges the buyer against the market price difference between two or more price zones. These contracts do not have an impact on the economic dispatch or on the actual use of the line. Financial transmission rights can be obligations or options. Obligations imply that the rights holder receives the value of the entitlement when it is positive but must pay the counterparty to the contract if it is less. With options, the holder is not obligated to pay the counterparty if the value of the entitlement is negative.'* The difference between obligations and options is further illustrated in Box 1.

According to the FCA, both FTRs and PTRs can be applied. However, the allocation of PTR and FTRs in parallel at the same bidding zone border is not allowed (FCA, Art. 31(6)). It is also important to note that PTRs are directly linked to the physical capacity of the line and the only selling counterparty can be the TSO.²⁵ In principle, FTRs can be issued by any market participant (Batlle et al., 2014). However, in the European context FTRs are generally also issued by the TSO and linked to congestion rents. This implies that the overall amount of PTRs or FTRs is limited to the physical transmission capacity (Spodniak et al., 2017).²⁶

²⁵ This means that the TSO (as counterparty) needs to be notified when market participants purchase or transfer long-term transmission rights that were already allocated.

²⁶ Additionally, the 'netting' of FTR obligations is also possible (selling contracts bi-directionally in both directions). Because of counter-flows, a higher volume than the actual transmission capacity may be issued. FTR obligations provide netting, but FTR options do not (Spodniak et al., 2017).

Box 1: Financial transmission rights (FTR): obligations vs options, illustrative exercise.

Imagine the following two situations under a certain energy delivery scenario. Which statement is wrong?

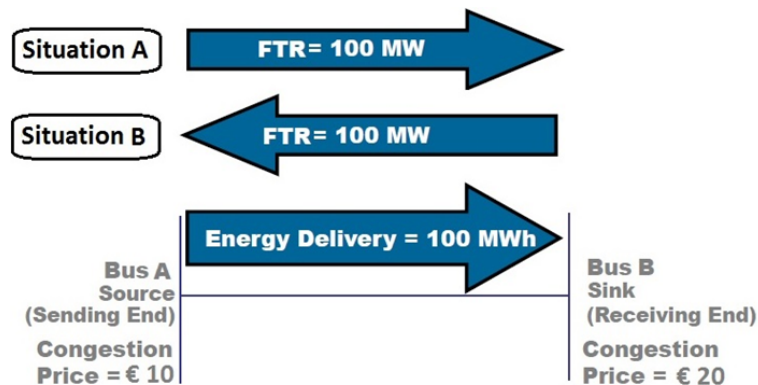


Figure 7: Energy delivery scenarios to illustrate the difference between obligations and options, based on PJM (2011)

- a.) If I hold an FTR-option in situation A, I gain €1000
- b.) If I hold an FTR-obligation in situation A, I gain €1000
- c.) If I hold an FTR-option in situation B, I lose €1000
- d.) If I hold an FTR-obligation in situation B, I lose €1000

The wrong statement: c

Justification: In situation A, the outcome for an option and an obligation are the same. The holder of both FTRs gain $(20 \text{ €/MWh} - 10 \text{ €/MWh}) \times 100 \text{ MWh} = \text{€}1000$. In situation B only the holder of an FTR-obligation has to pay $(20 \text{ €/MWh} - 10 \text{ €/MWh}) \times -100 \text{ MWh} = -\text{€}1000$. A holder of an option will not exercise the option in this case and would not lose any money (except the price paid beforehand for acquiring the option). In other words, in situation A both FTR-obligations and options are a benefit. In situation B, an FTR-obligation is a liability, while an FTR-option is neither a liability nor benefit.

Battle et al. (2014) describe in detail the pros and cons of PTRs and FTRs. They split their analysis into two parts. Firstly, an ideal market operation and structure is assumed.²⁷ In that situation, PTRs and FTRs are equivalent. Secondly, an analysis is done under the conditions prevailing in real electricity markets, paying particular attention to situations where market power can be exercised. In that case, there are material differences between both products. The authors conclude that if there is sufficient inter-market coordination and liquidity, FTRs should be the preferred product. However, until these conditions are not attained, PTRs are the most suitable transitory solution. The advantages of FTRs over PTRs are found to be greater transparency, simplification of regulatory supervision and provision of a more valuable hedge for minority market share participants. With PTRs market participants with physical generation assets are clearly in a better position to engage in trading. This is not the case for FTRs, and therefore FTRs would broaden the demand base, enhance competition and increase market liquidity. PTRs vs FTRs has been a strongly debated topic in the academic literature for a long time.

²⁷ According to Battle et al. (2014), an ideal market would imply: the absence of technical conditioning (physical flows equal commercial transactions), no regulatory design inefficiencies, unlimited liquidity, no transactions costs, no market power and fully rational market participants.

Overall, many arguments are found in favour of FTRs, examples of relevant work are Benjamin (2010), Chao and Peck (1996), Hogan (1992) and Joskow and Tirole (2000).

Box 2: The Nordic approach to long-term transmission rights (based on Spodniak et al. (2017))

Since 2000, the Nordic electricity market has its own standard product in use for hedging bidding area price differences, called the 'electricity area price differential' (EPAD). EPAD contracts are used to build a hedge for a bidding area price in relation to the Nordic system price (a sort of benchmark price, there is no similar system price in the rest of Europe), while an FTR contract hedges the price difference directly between two adjacent bidding areas.

To hedge the price difference between two adjacent bidding areas with EPADs as an FTR would do, a combination of two EPAD contracts (a so-called EPAD Combos) needs to be acquired by a market player. Two EPAD Combos are required to cover the hedge 'both ways' for each interconnector between two bidding zones. Spodniak et al. (2017) note *'this replication implies that it is theoretically and even practically possible to continue with the EPAD-based system by using EPAD Combos in the Nordic countries, even if FTR contracts would prevail elsewhere in the EU.'* Additionally, the authors do an empirical analysis and show that in practice the pricing of bi-directional EPAD contracts is more complex and may not always be very efficient.

A significant difference between FTRs and EPADs is that EPADs are purely financial contracts traded on a securities exchange, without a direct link to the transmission capacity of the interconnectors. As such, there is also no volume cap in terms of offered transmission rights.

Also in the work of Batlle et al. (2014), FTR-obligations vs FTR-options are discussed. A major difference between both is that obligations are allocated simultaneously in both directions (one product, one auction), while an option only covers the price risk in one direction (two products, two auctions). Although possible higher implementation costs and decreased liquidity can be expected with options, it is argued that these are favoured by market participants as in most cases market participants are interested in hedging the price risk in solely one direction.

Regarding pricing, the FCA states in Article 28 that marginal pricing should be applied for each bidding zone border, direction and market time unit. Marginal pricing implies that all successful bidders pay the price of the marginally accepted bid (in this case the lowest accepted bid). The price will equal zero if the demand for transmission rights is lower than the offered long-term cross zonal capacity.

3.2.4 Firmness

Trust in firmness, defined in the CACM as *'a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed'*, is a necessary condition for the successful integration of electricity markets. The potential interruption of exports during emergency or scarcity conditions can be a major barrier to the development of (long-term) cross-zonal trade (Mastropietro et al., 2015).

In the FCA, two causes for curtailment of long-term transmission rights are distinguished. First, the curtailment of transmission rights in the event of force majeure.²⁸ In that case, the holder of long-term

²⁸ A force majeure event is defined in the CACM as any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or

transmission rights will receive a compensation by the TSO which invoked the force majeure. This compensation will be equal to the amount initially paid for long-term transmission rights (FCA, Art. 56(3)). The national regulatory authority of the TSO invoking the force majeure event shall assess whether an event qualifies as force majeure (FCA, Art. 56(5)). Second, long-term transmission rights can also be curtailed prior to the day-ahead firmness deadline to ensure that operation remains within operational security limits.²⁹ The concerned TSOs on the bidding zone border where long-term transmission rights have been curtailed shall compensate the holder of these rights with the market spread (FCA, Art. 53(2)).³⁰ Further, the concerned TSOs on a bidding zone border may propose a cap on the total compensation to be paid to all holders of curtailed long-term transmission rights (FCA, Art. 54(1)).³¹

Mastropietro et al. (2015) argue that congestion is not the only source of price-differentials between bidding zones. They state that price-differentials may also originate from a direct regulatory intervention with the aim to prioritise national over regional interests. This would be the case if a TSO (prompted by a regulator) blocks exports through interconnectors when its system is under scarcity conditions. By doing so, a price-differential with no hedge is (artificially) created, and the execution of cross-zonal contracts is impeded. Mastropietro et al. (2015) add that, whenever the physical delivery is not possible because of an intervention from the TSO, the latter should pay not only the financial settlement related to the price differentials but additionally possibly some compensation. This compensation would constitute a penalty for non-compliance which a generator located in one bidding zone should pay to a demand located in another bidding zone when these two parties have signed a contract for the physical delivery of electricity, and the demand is not served.³² The TSO (representing the regulator and, eventually, the government) should also be required to deposit warranties guaranteeing such payments.

It is of great importance that the risks are properly allocated. Otherwise there is a risk of the TSO becoming more risk-averse and offering less long-term capacity than might be efficient or market participants might be disincentivised to engage in long-term cross-zonal trade.

economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this Regulation (CACM).

²⁹ 'Operational security limits' are defined as the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits (CACM, Art. 2(7)).

³⁰ Market spread refers to the difference between the hourly day-ahead prices of the two concerned bidding zones for the respective market time unit in a specific direction.

³¹ The cap holds for the accumulated compensations over the relevant calendar year and cannot be lower than the total congestion income collected during that same period (FCA, Art. 54(1,2)).

³² The compensation is related to the difference between the utility value that the demand attributes to its supply and the price cap active in the market (Mastropietro et al., 2015).

4. Establishing national day-ahead and intraday markets

The CACM is the key regulation outlining the design and integration of the day-ahead (DA) and intraday market (IDM). In this chapter, we focus on the establishment of the national DA and IDMs.³³ Their integration is discussed in Chapter 5. The ‘Target Model’ pursued by the European Commission (Third Energy Package, Directive 2009/72/EC) is centred around day-ahead auctions operated by power exchanges that implicitly allocate transmission capacity between bidding zones (Neuhoff et al., 2016c). Prices obtained in the DAM auction serve as a reference for forward markets (Meeus, 2011). In recent years, a strong increase in trading in intraday markets was observed, as is illustrated in Figure 8 (below). In that same figure, the trading volumes in the DAM as a share of the hourly consumption for France and Germany for a period from 2012 to 2015 are shown. It can be seen that large differences in proportional volumes exist between both countries. It can be argued that the centre of gravity of electricity trading is slowly moving closer to real-time.

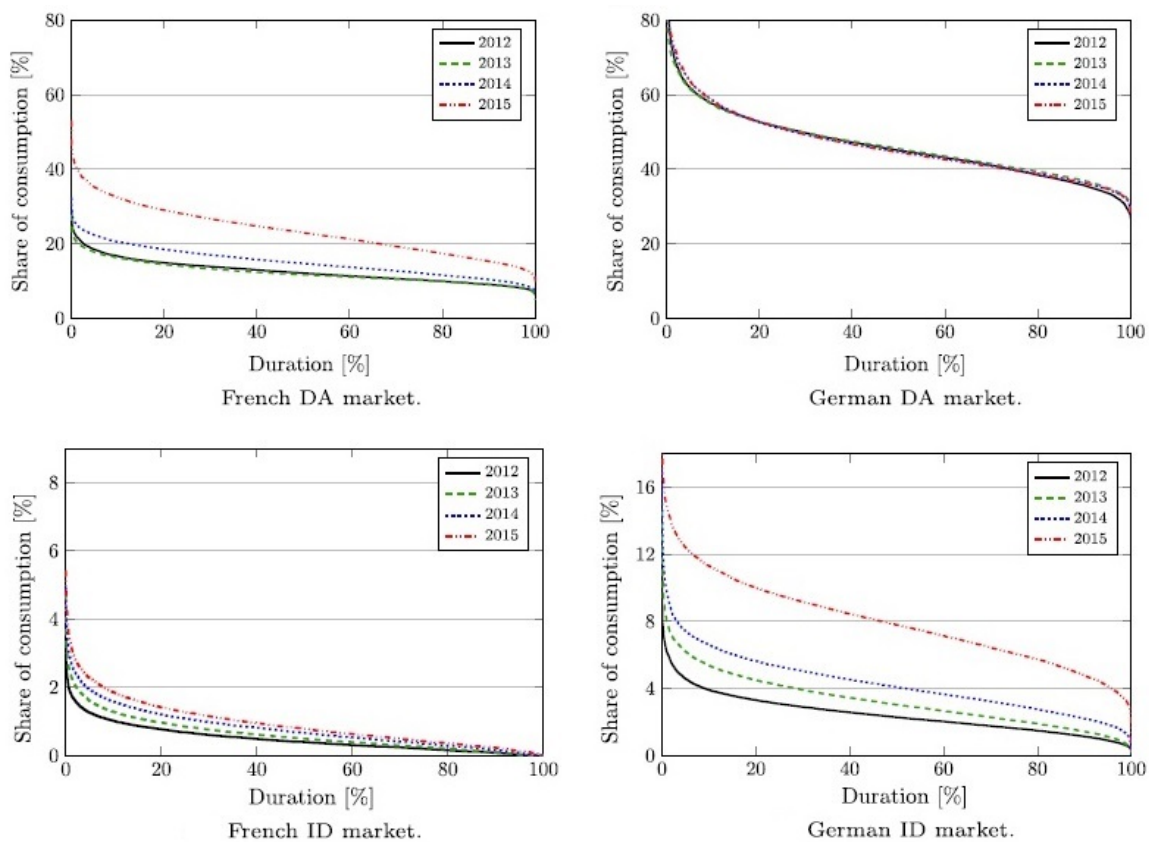


Figure 8: The hourly DA and ID market trading volume as share of the hourly consumption for France and Germany (Brijs et al., 2017)

Short-term electricity market design needs to evolve with its context. Originally, these markets were designed for large, rather slow ramping, and mostly fossil fuel based generators and inflexible demand. The same conditions do not exist now with the penetration of variable renewable energy sources (vRES) at all voltage levels and more options for consumers to manage their demand. How to adjust market design to this new context is a topic of extensive debate (for e.g. AGORA, 2016; Brijs et al.,

³³ National DA and IDMs can have for instance additional products (e.g. with a finer time granularity) next to the products traded in the single European (coupled) DA and IDM. These products are traded after the cross-zonal DA gate closure time and are only national, bilateral or regional but not EU wide.

2017; Henriot and Glachant, 2013; Neuhoﬀ et al., 2016, 2015b). In general, it is agreed that ﬂexibility is required to allow for eﬃcient operation of the system with higher penetrations of vRES. Short-term electricity market design should encourage investment in the right technologies (capacity) and incentivise them to oﬀer their full ﬂexibility (capability). A combination of complementary actions is needed to achieve this goal. Integration of electricity markets at all market time frames is key to make better use of the resource diversity in the EU. Also, the day-ahead market design needs to be adapted, for example by introducing better-adapted bidding products. Furthermore, the functioning of markets closer to real-time needs to be enhanced, both intraday and balancing markets (treated in Chapter 6).

In this chapter, ﬁrstly, a key institution, namely the Nominated Electricity Market Operator (NEMO) and its functions are described. The DAM and IDM are both managed by power exchanges, which are now labelled as NEMOs in the EU, a concept introduced by the CACM. Afterwards, the main characteristics of the day-ahead market are discussed. Lastly, several important elements of intraday market design are discussed.

4.1 Nominated Electricity Market Operators (NEMOs)

Power exchanges traditionally collected and matched bids and oﬀers within diﬀerent time-frames for a certain bidding zone. Recently, power exchanges have been increasingly organising trade between zones in Europe, which was previously mainly the territory of the Over-The-Counter (OTC) electricity trading business (Meeus et al., 2005; Meeus, 2011). To make electricity trading over borders happen smoothly, an institutional framework for power exchanges is required. Such framework is provided by the CACM. In the CACM common requirements for the designation of NEMOs and for their tasks are outlined.³⁴ In short, NEMOs can be seen as power exchanges certiﬁed to organise cross-zonal electricity trade.

4.1.1 Scope and tasks

In the CACM, it is stated that each Member State (MS) shall ensure that at least one NEMO is designated in its territory (CACM, Art. 4(1,2)). However, if in a MS a national legal monopoly is in place by the time the CACM enters into force, that MS may refuse the designation of more than one NEMO per bidding zone (CACM, Art. 5(1)). An overview of the active number of NEMOs per MS and the institutions which designated the NEMOs is given in Figure 9 (left and middle). In the majority of countries only one NEMO is active, and in most cases, the regulator is in charge of their designation.

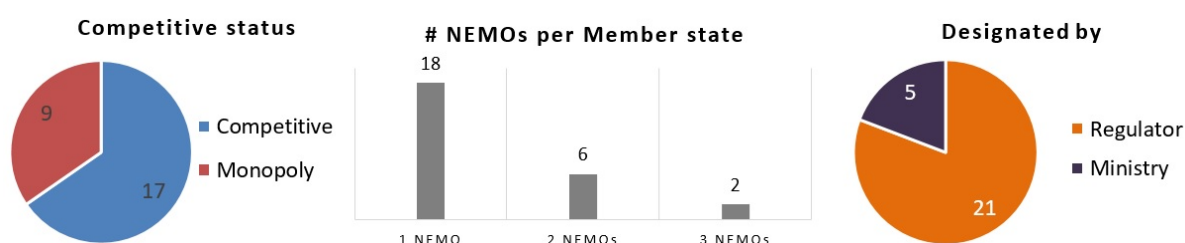


Figure 9: Facts and figures of NEMOs in the EU (excl. Cyprus and Malta). Based on ACER (2015a)

³⁴ A NEMO is defined in the CACM as an entity designated by the competent authority to perform tasks related to single day-ahead or single intraday coupling. Market coupling is the auctioning process where collected orders are matched and cross-zonal capacity is allocated simultaneously for diﬀerent bidding zones in a market time frame.

A complete overview per country can be found in ACER (2015a), in Figure 10 (left) the competitive status per country is visualised. In Figure 10 (right) the NEMOs active in MS open to competition for NEMOs is shown. Pursuant to Article 4(10) of CACM, the designating authorities shall inform ACER of the designation and revocation of NEMOs. ACER shall maintain a list of designated NEMOs, their status and where they operate on its website.

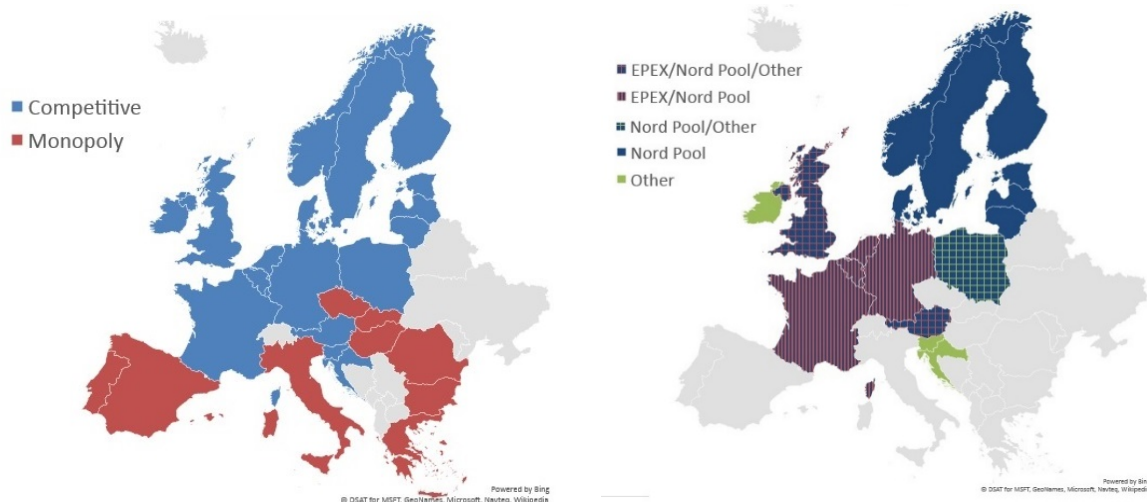


Figure 10: Left – Competitive status of NEMOs in the EU+NO. Right – State of play in MS open to competition in NEMOs. Based on ACER (2015a).

A NEMO can be designated for trading services in the day-ahead market, the intraday market or both. Today, all designated NEMOs offer services in both markets (ACER, 2015a). NEMO(s) designated in a MS have the right to offer trading services with delivery in another MS without the need for designation as a NEMO in that Member State, albeit with exceptions. These exceptions are summed up in Article 4(6) of the CACM.

In CACM, Article 7(1) the tasks of the NEMOs are outlined as follows: *‘Their [NEMOs] tasks shall include receiving orders from market participants, having overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices and settling and clearing the contracts resulting from the trades according to relevant participant agreements and regulations.’* Also, all NEMOs shall, in cooperation with the relevant TSOs, develop a proposal on harmonised maximum and minimum clearing prices to be applied in all bidding zones.³⁵ A proposal shall be made for the DAM and another for the IDM. NEMOs shall carry out market coupling operator (MCO) functions jointly with other NEMOs, for this purpose also a close collaboration with coordinated capacity calculators is required.³⁶

4.1.2 Cost-of-service regulated vs merchant

Meeus (2011) states that two types of power exchanges can be distinguished in Europe: cost-of-service regulated (monopoly) and merchant (competitive) power exchanges. Cost-of-service regulated are not-for-profit or regulated-profit institutions which receive an income from regulated fees. They can be established by a public initiative (e.g. OMEL in Spain) or by a TSO initiative (e.g. HUPX in Hungary).

³⁵ The clearing price is defined in the CACM as the price determined by matching the highest accepted selling order and the lowest accepted buying order in the electricity market (Art. 2(31)).

³⁶ In short, a coordinated capacity calculator (CCC) is set up jointly by a subset of TSOs (CACM, Art. 2(11)), and calculates the available cross-zonal transmission capacity per capacity calculation region (CCR).

Typically, they also perform several tasks that go beyond trading services. On the other hand, merchant power exchanges are for-profit market institutions whose core business is to provide trading services. Their income depends on various user fees and is linked to the volume of trades executed by the power exchange for its users. Examples are EPEX Spot (covering Germany, France, GB, the Netherlands, Belgium, Austria, Switzerland and Luxembourg) and Nord Pool AS (one of the NEMO(s) or single NEMO in 15 European countries). Historically, merchants were set up by market parties, financial market institutions, TSOs or a combination of private actors. In Figure 9 (right), the competitive status of a power exchange in the Member States is shown. In most countries, power exchanges are a competitive activity, however, in nine countries (e.g. Italy and Spain) they have a monopoly status.

The CACM does not prescribe whether NEMOs should be a monopoly or competitive activity. However, a preference for NEMOs as a competitive activity can be detected in the code. Namely, it is stated that *'a national legal monopoly is deemed to exist where national law expressly provides that no more than one entity within a Member State or Member State bidding zone can carry out day-ahead and intraday trading services'* (CACM GL, Art. 5(2)). However, *'if the Commission deems that there is no justification for the continuation of national legal monopolies or for the continued refusal of a MS to allow cross-border trading by a NEMO designated in another MS, the Commission may consider appropriate legislative or other appropriate measures to further increase competition and trade between and within MSS'* (CACM, Art. 5(3)).

Exchanges have natural monopoly characteristics. Firstly, trading systems can benefit from positive network externalities (liquidity attracts more liquidity). And secondly, significant economies of scale are present (Meeus, 2011). In brief, a trade-off exists. On the one hand, cost-of-service regulated power exchanges have fewer incentives to abuse market power and act anti-competitively than merchant power exchanges. On the other hand, they also have fewer incentives to provide an efficient trading service or to innovate in trading systems. Meeus (2011) argues that it does make sense to have merchant power exchanges, especially in the light of the integration of electricity markets. When dealing with problems related to cross-zonal trade, the national regulatory authorities frequently do not have effective and independent powers to define and enforce the necessary regulation at EU level. There could be a 'regulatory gap' created with cost-of-service regulated power exchanges. A merchant power exchange has a clear incentive to cooperate in the implementation of this model as it can generate significant additional trade volumes, and thus income for the power exchange. However, the market power of power exchanges should be tempered. This could be done by enhancing transparency requirements and introducing governance rules to prevent that cooperation among power exchanges would lead to closed cartels.

4.2 The day-ahead market (DAM)

In Europe, the day-ahead market is organised as a double-side blind auction. By noon of the day before delivery, market parties submit their offers and bids for each hour of the next day to the NEMO to adjust their positions held in forward markets. In the simplest form, orders are hourly price-quantity pairs. In Figure 11 an example of the clearing of an aggregated demand (blue) and supply curve (red) for one hour in a DAM session is given. For each (daily) DAM session 24 such clearings are performed. The supply offers (red) with a price lower than the clearing price, thus under the green line, are accepted. The accepted supply offers want to supply energy for a price lower than or equal to the clearing price. The demand bids (blue) above the clearing price, thus above the green line, are

accepted. The accepted demand bids are willing to pay at least the actual clearing price for energy. Marginal uniform pricing (pay-as-cleared) applies in the DAM auction, which means that all accepted supply offers and all accepted demand bids receive/pay the same (uniform) price, namely the clearing price.



Figure 11: Example of the clearing of an aggregated demand (blue) and supply curve (red) for one hour of the DAM in Romania on 24/01/2011 (Pérez-Arriaga, 2013)

In this section, three design dimensions of the day-ahead market are discussed in more depth. Namely, the bid formats accepted in the DAM auction, the temporal resolution of the products and the maximum and minimum clearing prices. Integration of cross-zonal DAMs is the topic of Section 5.1.

4.2.1 Bid formats: simple, block and complex bids

In the literature three types of bids are identified: simple price-quantity bids, (linked) block price-quantity bids and complex (or multi-part) bids. In an auction with uniform marginal pricing, as is the case in the DAM, the optimal bidding strategy for market participants is to bid their marginal cost.³⁷ Namely, if market participants bid higher than their marginal cost and their bid is not accepted, there will be instances where they could have made a profit, while if they bid lower there is a probability that they would lose money if they are called to generate. It can be argued that simple bids and an optimal bidding strategy are not compatible. The reason for this is that a generator cannot include non-convex costs, e.g. start-up cost and minimum run levels. These non-convex costs are becoming more prominent as the share of renewables increases in the generation mix.

One remedy which is used today in the DAM is to allow for block bids. Different formats of block bids exist, for more details see e.g. Meeus et al. (2009). In short, a block bid can be defined as an all-or-nothing order of a given amount of electric energy in multiple consecutive hours.³⁸ A minimum revenue needs to be obtained for the period of the block bid before acceptance. But, again for block bids, non-convex costs cannot be explicitly represented, and a mark-up needs to be included. Also, (computational) time needed to find a solution for the clearing algorithm increases with the introduction of block bids. The CACM states in Article 40(2) that the products covering one market

³⁷ It should be added that this statement only holds in the absence of market power (i.e. in the absence of ability to affect prices).

³⁸ It is important to mention that block bids can have different meanings. For example, in the US 'a block bid' can simply imply a one-hour bid of which also a part of the total quantity offered can be cleared.

time unit (an hour) and multiple market time units (multiple hours) should be accommodated by the matching algorithms of the NEMOs. This implies simple and block bids to be within the boundaries of the regulation.

Neuhoff et al. (2015a, 2015b) and Neuhoff and Schwenen (2013) provide five arguments in favour of complex bids, wherein non-convex costs are explicitly presented, over simple and block bids. Firstly, less informed (smaller) participants have greater difficulty determining the optimal mark-up to incorporate in their block bids. If mark-ups are not set at an appropriate level, which is probable, the efficiency of the market outcome decreases, while transaction costs and the uncertainty for market participants increase. Second, market monitoring for block bids is almost impossible as the underlying costs structure is not defined. In contrast, complex bids with energy bids and ramping and start-up costs nominations follow auditable cost structures. Third, simple and block-bidding do not lend themselves easily to the provision of early and reliable unit specific generation patterns. By using energy-only bids the flexibility of thermal generation assets cannot be made fully available to the market, generation is often optimised within the portfolio of utilities or aggregators with the implication that system operators have limited information on the ultimate generation pattern to be considered for flow calculations. Also, it is argued that in contrast to block bids, the reflection of technical characteristics in complex bids – instead of combinatorial questions – is more suitable for computation of market clearing. Lastly, with block bids, the liquidity in standardised auctions might be undermined as bids only are valid conditional on being accepted for longer time durations. Today, complex bids are present mostly in the US electricity markets, but also in some European markets, e.g. Spain and Poland (Brijs et al., 2017; Neuhoff et al., 2016c).

A commonly used argument against complex bids made by generators is that they would need to reveal commercially sensitive information in their bids. Neuhoff et al. (2015b) state that it is expected that the level of information sharing will not be extended beyond the level of sharing that is already necessary with TSOs. Meeus and Belmans (2007) state that with block-bids the pricing approach in dealing with non-convexities is simpler than with complex bids. Arguably, it can be harder to couple markets allowing for complex bids because they can apply a different implementation of non-linear pricing internally.³⁹ The reason is that it is politically difficult to harmonise the treatment of non-convexities and especially if the treatment is already fine-tuned, which is less the case with easier-to-harmonise block bids. The CACM states that NEMOs shall submit a joint proposal concerning products that can be taken into account in the single day-ahead market coupling (CACM, Art. 40(1)). It is added that the orders resulting from these products should be expressed in euros and make reference to the market time.

4.2.2 Temporal granularity

Today, in the European DAM the market time unit of traded products is one hour. This granularity in the DAM is not directly seen as problematic in the academic literature, under the condition that

³⁹ Without going into too much technical detail, when allowing for block bids and/or complex bids, it is not always feasible to find a clearing price for which all accepted offers are in-the-money (not making losses), or for which all rejected offers are out-of-the-money (making money). Broadly speaking, in the US, with complex bids, some accepted offers are making losses when considering solely the clearing price. This problem is solved with uplift payments. In Europe, with block bids, some rejected block offers could be making money considering the clearing price, these are so called ‘paradoxically rejected blocks’ (Meeus et al., 2009). See also, section 2.2.2. in Papavasiliou and Smeers (2017).

products with finer resolution are offered in intraday markets and/or locally. However, it is clear that the finer the granularity, the more volatile the prices. These prices can better reflect and reward the value of flexibility in the system. Units can take advantage of price volatility when they can ramp up or ramp down faster. Flexible resources need clear signals to encourage investment and to deliver energy when needed. A shorter market time-unit can deliver these incentives.

Also, some issues might occur as the settlement period over which market participants are financially responsible for having a balanced portfolio is 15 minutes or 30 minutes.⁴⁰ Therefore, shorter market time-units would allow for a better alignment of trading in the DAM and imbalances in real-time (Brijs et al., 2017). If demand and supply schedules are scheduled on a shorter time interval, reserve requirements might be reduced (Neuhoff et al., 2015a).⁴¹ Shorter time-units also help in shifting the risks from TSOs to market parties responsible for balancing their demand and supply (Frunz, 2011).⁴² Less intervention from the TSO should be required, and thus fewer costs would be socialised (Henriot and Glachant, 2013). In other words, by having more granular products the deterministic imbalances, meaning imbalances introduced due to scheduling and not due to unpredictability in generation/demand or unforeseen events, are expected to be more limited (Hirth and Ziegenhagen, 2015).

Counterarguments are that non-convexities are even harder to include in simple bids with finer temporal granularity and that the computational time to clear the market might increase significantly as more combinations are possible (Henriot and Glachant, 2013). Neuhoff et al. (2016) explain that the finer the granularity of the bids, the greater the need for complex bids.

4.2.3 Maximum and minimum clearing prices

A general remark made in the literature is that price caps and floors should be removed as they distort the price signal and limit the ability of peaking units or more flexible resources to recover their capital costs, contributing to the ‘missing-money’ problem. There is no theoretical rationale for a limit to price floors (Henriot and Glachant, 2013) and with more participation of the demand side, increasing storage possibilities and a weaker presence of market power there are fewer reasons to hold on to price caps as well. Removing price caps will give market participants a high degree of planning security. Additionally, Hogan (2013) argues that higher price caps are a necessary, but not sufficient condition, to be consistent with a reasonable market for addressing scarcity conditions. However, in times of scarcity, it is difficult or impossible to distinguish real scarcity in supply from the exercise of market power.

In the CACM, it is outlined that NEMOs, in cooperation with TSOS, shall develop a proposal on harmonised maximum and minimum prices to be applied in all bidding zones which participate in single day-ahead coupling (SDAC) (CACM, Art. 41). The CACM provides that the proposal must take into account an estimate of the value of lost load, intending to provide for an element of scarcity. In November 2017, ACER adopted a decision regarding the proposal of all NEMOs on harmonised

⁴⁰ For more details, please consult Chapter 6 in which the balancing mechanism is presented.

⁴¹ Shorter market time-units alone are not a sufficient condition for reducing reserves. E.g. shorter intraday gate closure times, discussed in Section 4.3.3, seem also to be key to reduce reserves.

⁴² So-called ‘Balance Responsible Party (BRP)’, explained in the introduction to Chapter 6.

maximum and minimum prices for the SDAC (ACER, 2017a).⁴³ ACER approved that the harmonised maximum clearing price for SDAC shall be +3000 EUR/MWh and the harmonised minimum clearing price for SDAC shall be -500 EUR/MWh. However, the harmonised maximum clearing price will not be static, namely, the harmonised maximum clearing price for SDAC shall be increased by 1,000 EUR/MWh in the event that the clearing price exceeds a value of 60 per cent of the harmonised maximum clearing price for SDAC in at least one market time unit in a day in an individual bidding zone or in multiple bidding zones. Therefore, the harmonised maximum clearing price cannot really be seen as a ‘true price cap’ blocking scarcity prices from occurring.

4.3 The intraday market (IDM)

Higher shares of wind and solar generation result in increasing volumes of intraday trading (see also Figure 8 (below) on page 20). Closer to real-time, wind- and solar (but also demand) forecasts are more accurate and in intraday markets production schedules can be adjusted accordingly. While the day-ahead market design is quite harmonised in the EU, the same cannot be said about intraday market design. In some countries, e.g. Belgium, France and the Netherlands, shortly after the DAM auction, continuous trading with hourly products is possible (Brijs et al., 2017). In other countries, e.g. Spain, multiple intraday auctions are held (Hagemann and Weber, 2015). In Germany, a combination of continuous trade and auctions is in place (Neuhoff et al., 2016b). As an illustration, in Figure 12 the EPEX trading process in Germany is shown in more detail.

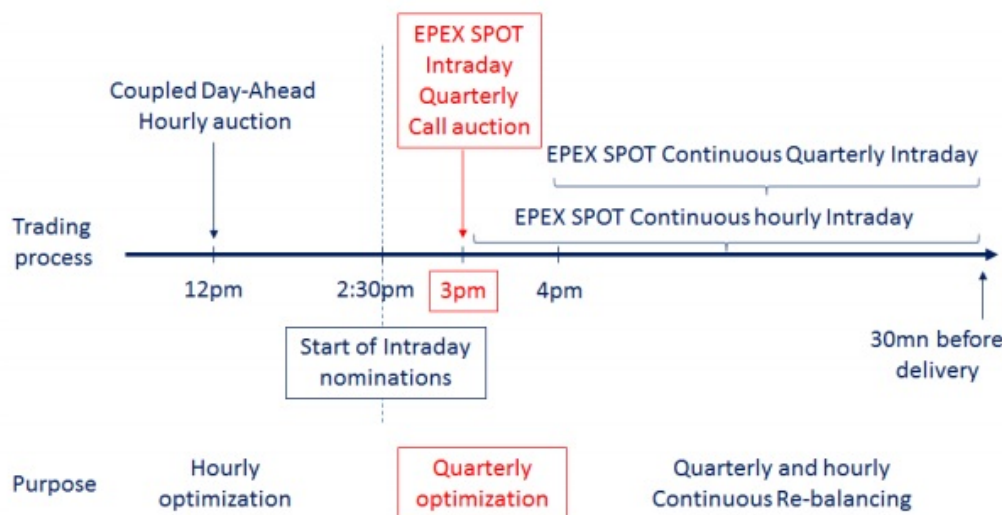


Figure 12: Trading process from the DAM to the IDM gate closure in Germany by EPEX (from Neuhoff et al., 2016b)^{44,45}

⁴³ A proposal was also approved regarding the harmonised maximum and minimum prices of the single intraday coupling (SIDC). The harmonised maximum clearing price for SIDC shall be +9999 EUR/MWh and the harmonised minimum clearing price for SIDC shall be -9999 EUR/MWh (ACER, 2017b). The harmonised maximum clearing price for the SIDC will be set equal to the SDAC harmonised maximum clearing price if that price would exceed +9999 EUR/MWh after adjustments.

⁴⁴ In March 2017 also 30-minute products were introduced for continuous trading, these products are not displayed in Figure 12 (EPEX SPOT SE, 2017).

⁴⁵ 15-minute products were introduced in 2011 (continuous trading) and 2014 (auction). Märkle-Huß et al. (2018) analyse in their paper the causal impact of 15-minute trading on the EPEX Spot market and find that the introduction of 15-minute products caused a reduction of the prices of existing hourly contracts and incentivizes renewable energy providers to offer additional electricity.

In Germany, first, 3 hours after the day-ahead auction an intraday auction with 15-minute products (thus $24 \times 4 = 96$ intervals) is held. It can be argued that not much new information is available for market participants from the gate closure of the DAM and this IDM auction. Instead, this auction is primarily held to allow for adjustments after the outcome of the DAM and to schedule German generation and demand with a finer temporal granularity.⁴⁶ Just after, the continuous intraday trading with hourly products starts. Lastly, one hour later, intraday trading with 15-minute products initiates. 30 minutes before real-time delivery the intraday market gate closure takes place, and no more trading is possible. The goal of continuous intraday trading is different in this context as trading closer to real-time is possible. Its aim is to allow market participants to adjust their positions when better forecasts of renewable production and demand are available, or when unexpected plant outages take place.

A ‘hot topic’ in the EU is whether continuous trading, auctions or a combination is the best trading mechanism to conduct trades in the IDM. This question is discussed in this section. Afterwards, the liquidity in intraday markets is described noting that liquidity cannot be decoupled from the discussion about the best trading mechanism. The last subsection concerns the intraday gate closure time, the moment when trading is no longer possible and the TSO takes over the balance of the system. Regarding maximum and minimum clearing prices the same logic as for the DAM holds in the IDM.

4.3.1 Continuous trading vs auctions

Continuous trading has historically been the mechanism in place for intraday trading. In exchange based continuous trading, market participants submit limit orders to the order book at any time during the trading session.⁴⁷ All market participants can see the order book. Orders are matched if a new limit order is submitted that is either a buy-order with a higher price than the current best ask or a sell-order with a lower price than the current best bid (Neuhoff et al., 2016b). Of the matched offers, the initially submitted offer sets the price. This implies that buyers/sellers receive the price they bid/offer (pay-as-bid) and that each transaction during the intraday trading session can have a different price. This is one of the key differences with auctions, whereby when uniform pricing is the clearing rule, all buyers/sellers see the same price. In Box 3 the optimal clearing rule is discussed.

The CACM states that continuous trading should be in place in the intraday time frame. The matching algorithm should be able to accommodate orders covering one market time unit and multiple market time units (blocks). The market time unit is not specified and shall be defined by a proposal submitted by the NEMOs (CACM, Art. 53). Next to continuous trading, complimentary regional intraday auctions may be implemented if approved by the regulatory authorities (CACM, Art. 63). The CACM also requires the pan-European solution based on continuous trading to be complemented by ‘reliable pricing of capacity’ (see Section 5.2.2 for more details).⁴⁸

⁴⁶ This auction is not opened for cross-zonal generation/demand.

⁴⁷ A limit order is a price-quantity pair and allows you to specify the maximum amount you are willing to pay for electric energy (when you buy) or the minimum amount you are willing to receive for electric energy (when you sell). A market order, also often allowed, solely specifies a quantity and is used to buy or sell immediately at the best available price.

⁴⁸ In line with Article 55 of CACM, all TSOs have submitted to the National Regulatory Agencies (NRAs) a methodology for intraday capacity pricing which would introduce an auction at the intraday cross-zonal gate opening time in the European Intraday market (ENTSO-E, 2017f).

Box 3: The optimal auction clearing rule – Marginal (or uniform) pricing vs pay-as-bid

With continuous trading, pay-as-bid is implicitly the clearing rule used. With an auction, either pay-as-bid or uniform pricing can be opted for. In DAM auctions, marginal pricing is in place and in IDM auctions in Germany, Spain, Italy and Portugal also the marginal pricing rule is implemented. However, in the balancing markets (BM) both marginal and pay-as-bid rules are employed in the EU.

One paper is very frequently cited in the literature regarding this matter, namely 'Uniform pricing or pay-as-bid pricing: a dilemma for California and beyond' by Kahn et al. (2001). The most important idea brought forward in the paper is that the common mistake made by people advocating that pay-as-bid pricing would lead to lower costs compared to uniform pricing is the fact that bidding strategies will be very different according to the clearing rule in place. Under pay-as-bid, the market participants would no longer have an incentive to bid their avoidable costs but, instead, would base their bids anticipating the market price. This would largely remove the hoped-for savings from pay-as-bid (Littlechild, 2007). The main arguments made in favour of marginal pricing over pay-as-bid pricing are (Kahn et al., 2001; Littlechild, 2007; Müsgens et al., 2014):

- Pay-as-bid introduces some inevitable reduction in efficiency as generators depart from bidding their marginal costs. Because if they solely bid their marginal cost and their bid is accepted, they won't receive any compensation for their fixed costs or a contribution to profits. With all bids exceeding the marginal costs, by amounts that depend upon the varying estimates of the bidders of what would be the highest accepted bid, the perfect, total cost-minimizing merit order dispatch is no longer assured.
- Another inefficiency introduced by pay-as-bid is the cost of forecasting market prices that it would impose on all participants. There are significant economies of scale in the efforts to gather the necessary information and make such forecasts on a continuing, hour-by-hour and day-by-day basis. The data analytics necessary to forecast market pricing dynamics are complex and costly. Under pay-as-bid, large players are more likely to have the resources available to gather better insight in bidding strategies and thus gain an advantage by forecasting prices. In short, marginal pricing rewards low costs (because all winners get the same price) whereas pay-as-bid rewards good (but costly) guesses (because guesses determine the price).
- There is a greater transparency of bidding under uniform pricing than under pay-as-bid facilitating attempts to detect uncompetitive behaviour. If the market were competitive, all bidders would have the incentive under uniform pricing to bid their marginal costs. Since at least marginal generating costs are relatively easily measured, it should be feasible to ascertain whether bid prices had exceeded those levels.
- Under pay-as-bid no transparent price to serve as a benchmark for contract markets is available. Neuhoﬀ et al. (2016a) argue that a price reference closer to real-time is necessary.
- Under pay-as-bid a supplier with market power can be successful in an auction with a bid increased beyond what would have been the bid in a competitive market. Under uniform price the monopolistically leveraged price automatically goes to all competitors alike. However, as discussed below, with marginal pricing there are also concerns when market power is present.

An argument against marginal pricing is:

- Market power is the main concern when marginal pricing is applied. Namely, if there is imperfect competition and marginal pricing in place, suppliers with market power have incentives to reduce supply that could otherwise be profitably operated. The reason is that reducing supply

may increase the market clearing price and thus the profitability of the infra-marginal units. An analogous strategy is not possible with pay-as-bid, because bids on one unit cannot directly influence the payments for other units.

Overall, auction theory does not find a unique ranking with respect to efficiency or procurement costs regarding the settlement rules (Ausubel and Cramton, 2002). However, considering all arguments summarised in this Box, marginal pricing seems to be favoured for auctions in electricity markets.

Next to the arguments in Box 3 summing up the benefits of auctions with uniform prices, three additional arguments in favour of auctions can be added:

1/ Allocation of cross-zonal transmission capacity (discussed in more detail in Section 5.1.1): One of the most important arguments in favour of auctions in the IDM is the fact that auctions would facilitate the coupling of the IDM as the DAM is coupled today. One of the challenges with coupling is the allocation of cross-zonal transmission capacity. The most efficient solution would be to hold intraday auctions which simultaneously allocate transmission capacity (implicit allocation). Combining efficient allocation of transmission capacity with continuous trading is not straightforward (Neuhoff et al., 2016b). With continuous trading in place, valuable transmission capacity would be allocated on a first-come-first-served basis, thus possibly favouring more rapid/experienced traders instead of efficient ones. Extending this point, auctions would prevent robots capturing increasing shares of bid-ask spreads and scarcity value of transmission capacity in the market.

2/ Liquidity (discussed in more detail in the next subsection): The (single) price obtained from an auction increases price transparency, this is not the case with continuous trading whereby an average or other indices need to be computed. A liquid and transparent intraday price is beneficial especially for hedging and ultimately for providing clear price signals to attract investment in flexibility (Neuhoff et al., 2015b). In contrast, this stretching of liquidity over the whole trading period when continuous trading is in place can make the intraday market price volatile and non-transparent (Hagemann and Weber, 2015). Also, auctions tend to involve significantly lower fees for participants trading in intraday markets (Neuhoff et al., 2015b). Additionally, continuous trading is unlikely to deliver the liquidity for different types of block-bids to support efficient bilateral matching (Neuhoff et al., 2015b).

3/ Operational security: Auctions are operationally simpler for the exchange and involve lower risk of technical malfunctions of market systems (Neuhoff et al., 2016b). Additionally, Neuhoff et al. (2016a) explain that as generation units will mark-up their bids during continuous intraday trading to reflect opportunity costs, the market outcome may not reflect an efficient generation schedule. In a subsequent real-time balancing auction with uniform pricing, generation units will submit bids reflecting their marginal cost and the auction clearing results in a least-cost generation schedule. This might imply significant adjustments to the output of individual power stations resulting in greater uncertainty regarding flow patterns very close to real time.

An argument in favour of continuous trading is made by Henriot (2012). He argues that continuous markets provide participants with a sufficient degree of freedom to express their needs, while discrete auctions may lead to inefficiencies due to lost trading opportunities. In this vein, Hagemann and Weber

(2015) mention that continuous markets allow 24/7 trading and thus market participants may trade imbalances as soon as they appear. Hence, new information can be used continuously. Additionally, Bellenbaum et al. (2014) state that the longer time lag for auction-based trading between gate closure and actual delivery tends to lower the informational efficiency.

4.3.2 Liquidity in the IDM

Liquidity is necessary to have a clear price signal in the IDM for market participants to offer their flexibility in this market on the short term and encourage investment in the long term. At the time of writing, liquidity is still a concern in most EU intraday markets. Figure 13 gives an overview of the liquidity in the IDM in some European countries using data from 2012.

An easy inference that could be made from Figure 13 is that an auction-based market design in the IDM fosters liquidity. ID auctions in Spain and Italy show a higher liquidity than IDM of other European countries with continuous trading in place. This observation is studied in the paper by Hagemann and Weber (2015) and discussed by Chaves-Ávila and Fernandes (2015). Hagemann and Weber (2015) conclude that the high volumes observed in auction-based intraday markets cannot be explained by the auction-based design but are mainly caused by market peculiarities. They developed an analytical method which considers wind and solar power forecast errors, power plant outages with relevance for intraday trading, market concentration and portfolio internal netting options as the main drivers of trading volume.

Country	Grid operator	Intraday exchange	Intraday gate closure ahead of delivery (min)	Intraday market design	National consumption (TWh)	Intraday trading Volume (TWh)	Share of national consumption (%)
Denmark	Energinet.dk	Elbas	60	Continuous	31.4	0.45	3.4
France	Réseau de Transport d'Electricité	Epex Spot	45	Continuous	434.1	2.2	0.5
Germany	50Hertz, Amprion, Tennet, TransnetBW	Epex Spot	45	Continuous	525.8	15.8	3.0
UK	National Grid	APX Power UK	60	Continuous	317.6	10.4	3.3
Italy	Terna	Gestore dei Mercati Energetici	255 – 690	Auction	296.7	25.1	8.5
Portugal	Redes Energéticas Nacionais	OMEL	135	Auction	46.2	5.2	11.3
Spain	Red Eléctrica de España	OMEL	135	Auction	240.2	46.8	19.5

Figure 13: Intraday markets in selected European countries with 2012 data (Hagemann and Weber, 2015)

Next to these fundamental drivers, one of the most important reasons found for the high liquidity in the Italian, Spanish and Portuguese market was that rescheduling of power plants' generation output within one generation portfolio is only possible via trades in the intraday market. No bilateral trade after the DAM and internal portfolio netting outside of the market are allowed (Rodilla and Batlle, 2015). Additionally, Hagemann and Weber (2015) also argue that renewable support schemes have an influence on IDM liquidity. In countries with low-risk support schemes, such as a feed-in tariff (FIT), the

balancing responsibility is typically transferred to the TSO (or DSO). TSOs need to trade the imbalances on the intraday markets, raising the trading volume. On the contrary, in countries with high-risk support schemes, such as feed-in premiums (FIP), the owners of vRES are responsible for their forecast errors. Unlike the TSO, these parties can either use controllable generation for internal self-balancing or do not manage forecast errors actively in the intraday market if they are too small.

Chaves-Ávila and Fernandes (2015) and Rodilla and Batlle (2015) also mention three other reasons explaining the high liquidity in the Spanish market. Firstly, there is an additional upward regulation reserve, which can be called upon, consisting of units which were not dispatched in the DAM. If a unit gets selected in this market, it is forced to bid into the IDM in order to get committed. Also, there is a national coal support mechanism which has given incentives to some units to avoid being committed in the DAM and to bid in the IDM instead. And lastly, price arbitrage opportunities have been identified between DAM and IDM in recent years. These might have been (partly) caused by the regulation around this upward reserve and the national coal support scheme.

As mentioned before, in December 2014, an auction with 15-minute products was introduced in Germany (Figure 12). Neuhoff et al. (2016b) have observed that the implementation of this auction led to increased liquidity. They find that traded intraday volumes with 10-15 GWh have been much higher than with continuous trading alone that rarely cleared more than 5 GWh. In contrast with Hagemann and Weber (2015) and Chaves-Ávila and Fernandes (2015), Neuhoff et al. (2016b) do not attribute the high liquidity levels to market peculiarities, but more clearly argue in favour of intraday auctions over continuous trading in the IDM.

Not yet mentioned in this discussion but extremely relevant to this matter is the fact that sufficiently high imbalance settlements, paid when a party is found to be unbalanced in real-time, should give an incentive for market participants to balance their output on the IDM. If these price signals are not strong enough, market participants will not feel the need to trade on the IDM and liquidity will remain low. Additionally, if vRES were held responsible (preferably under the same rules as conventional units) for their imbalances, they would be forced to trade in the IDM. Also, transparent 'near-real-time' information about the system state is of crucial importance. If market participants have this information, they can estimate potential imbalance settlements and they will be strongly incentivised to balance their positions in the IDM, especially when it is highly needed from a system perspective. In brief, a well-functioning liquid IDM depends on well-designed imbalance settlement rules.

4.3.3 IDM gate closure: the gap between trading and real-time operation

As implicitly stated in Article 59 (2) of the CACM, the length of the IDM gate closure is a trade-off between:

'(a) a maximisation of market participants' opportunities for adjusting their balances by trading in the intraday market time-frame as close as possible to real time;

and (b) providing TSOs and market participants with sufficient time for their scheduling and balancing processes in relation to network and operational security.'

Further, it is stated in the CACM that the intraday cross-zonal gate closure time, the gate closure time for cross-zonal transmission capacity, shall be at most one hour before real-time (CACM, Art. 59(3)).

Intraday energy trading for a given market time unit for a bidding zone border shall be allowed until the intraday cross-zonal gate closure time (CACM, Art. 59(4)).

The closer gate closure to real-time, the better vRES will be able to update their forecasts and the more they will be trading in the IDM to avoid imbalances (if imbalance settlements give the required incentive to adjust). A gate closure closer to real time will lead to a higher liquidity in the intraday market and a better deployment of flexible resources, the only resources, next to (fast) demand response (DR), that are able to adjust their output close to real time. Because of a more accurate dispatch of flexible peak units, fewer power plants will have to operate (inefficiently) at partial load in order to deliver balancing services (Müsgens and Neuhoff, 2006). Also, less reserve power capacity may need to be contracted, and less real-time action of the SO should be required, which would lead to a lower system cost if borne out.⁴⁹

The main driver of the time lag between gate closure and real-time is the fact that grid operators require sufficient time after the closure of trades to check system stability and take any necessary measures before real-time. It is undeniable that the level of coordination between TSOs and power exchanges will become increasingly important to minimise the gap between gate close and real time.

4.4 Matching markets with grids: redispatch and countertrading

In Europe, zonal pricing is applied as described in Section 2.1. In short, this means that electricity is traded in a bidding zone which is linked to other bidding zones. The physical network within a bidding zone is treated as a copper plate (no network constraints), while the limitations of links between bidding zones are taken into account when trading. If cross-zonal links are congested between the bidding zones, the respective markets are 'split'; if not, the markets are 'coupled'. Coupled markets imply the aggregation of supply and demand curves for the coupled zones when clearing the market.

Not incorporating grid constraints within bidding zones is a serious simplification. The flows which would result from electricity trading do not always lead to feasible flows over all lines within a bidding zone (internal congestion). Internal congestion is a structural problem in several regions in Europe, aggravated by the rapid increase in renewable generation and more volatile cross-zonal trade (ACER and ENTSO-E, 2012; Dijk and Willems, 2011; Kunz and Zerrahn, 2016; Van den Bergh et al., 2015).

In the short run, network congestion can be relieved by non-costly preventive measures, such as changing grid topology or by costlier curative measures, such as countertrading or redispatch. With countertrading or redispatch, the TSO arranges an increase in generation at one end of the congested grid area, compensated by a decrease at the other end. The costs of these deviations from the spot market dispatch are socialised through network tariffs (Kunz and Zerrahn, 2016). If countertrading or redispatch opportunities are not available, TSOs may curtail previously allocated cross-zonal capacities. In that case, the owners of transmission rights have to be compensated.

Definitions of countertrading and redispatch are found in a presentation by ACER and ENTSOE (2012):

⁴⁹ This claim is related to the discussion around the TSO's balancing energy activation philosophy described in Section 6.4. of this text.

- *Redispatch: ‘Any measure activated by one or several system operators by altering the generation and/or load pattern in order to change physical flows in the Transmission System and relieve a physical congestion. The precise generation or load pattern alteration is **pre-defined**.’* Redispatching can be:
 - Internal redispatching: the redispatching is performed in the bidding zone where the congestion is.
 - External redispatching: the redispatching is performed in bidding zone A whereas the congestion is on bidding zone B.
 - Cross-zonal redispatching: the redispatching is carried out in different bidding zones
- *Countertrading: ‘Cross zonal energy exchange initiated by system operators between two bidding zones to relieve a physical congestion. The precise generation or load pattern alteration is **not pre-defined**.’*

Redispatch can further be distinguished between preventive redispatch that is used to maintain the system in normal state and curative redispatch, which is activated immediately or relatively soon after operational security limits are violated (e.g. Netzstabilitätsanlagen in Germany).

In the CACM, Article 35(5) it is stated that the pricing of redispatch and countertrading shall be based on:

‘(a) prices in the relevant electricity markets for the relevant time frame; or

(b) costs of redispatching and/or countertrading resources calculated transparently on the basis of incurred costs.’

ACER and CEER (2016) report that the remuneration of activated internal or cross-zonal redispatching differs among Member States. It is found that the most common method used is the pay-as-bid pricing followed by the regulated pricing based on either a market price (e.g. DAM 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).⁵⁰

Redispatch and countertrading are short-term solutions to solve internal congestion. In the long run, the TSO can build new lines to accommodate the flow patterns. Alternatively, bidding zones can be redrawn or nodal electricity markets can be introduced. Nodal pricing is applied in some regions of the US (e.g. PJM) and can be considered as an extreme form of zonal pricing, namely each node in the transmission network becomes a bidding zone. Dijk and Willems (2011) explain that *‘under nodal spot pricing, electricity prices reflect physical constraints, and hence, scarcity of the transmission network. In the short run, nodal spot prices, therefore, ensure optimal usage of the transmission network. Over the long term, they give the optimal incentives for new investments.’*

⁵⁰ It can be argued that the best approximation for a fair redispatch price would be the price of the balancing market at the relevant market time unit (and not the DAM price), since redispatch is (or should be) activated close to real time. More precisely, the activated energy for redispatch has not been sold in the DA or IDM, hence, the market price was lower than the production/opportunity costs. Better pricing of redispatch would lead to increased efficiency in the scheduling of available generation/demand units.

None of these three solutions is without downsides. Building new transmission lines cost time, just as redrawing bidding zones do, and nodal pricing is not in line with the European target model for many reasons.⁵¹

Lastly, it is generally agreed that closer cooperation in congestion management between TSOs has a beneficial impact. More specifically, the sharing of network and dispatch information, cross-zonal counter-trading, and multilateral redispatch can reduce overall system costs and allow for more cross-zonal capacity to be offered to the market (ACER and ENTSO-E, 2012; Kunz and Zerrahn, 2016). For that reason, the CACM (Art. 35) strongly advocates more coordinated remedial actions, in particular for cross-zonal relevance. For example, TSOs, at least within a capacity calculation region, shall agree on a common redispatching and/or countertrading arrangements. Also, Article 74 describes that a redispatch and countertrading cost-sharing methodology will be developed as coordinated remedial actions can have distributional effects.

⁵¹ For a discussion of the EU vs US view on electricity market integration, please consult a recording of the FSR online debate on this topic: <https://www.youtube.com/watch?v=UerHK6DQH64>

5. Integrating day-ahead and intraday markets

Glachant and Lévêque (2006) identified the improvement of the congestion management of interconnectors to be the single priority action to be undertaken to foster the internal EU electricity market. After significant progress, ten years later, Glachant (2016) describes the formation of an internal electricity market as follows:

‘The EU opened its many national power markets without a “Target Model” of any kind (and then without a common “Market Design”) and stayed as such for 13 years (1996–2009). A “Target Model” finally emerged, but it had never been defined in any European single regulation or Green Paper. It has been produced by qualified European actors through an institutional process originated in the 3rd European Energy Package. This “Target Model” has at least three key characteristics:

- *1° It brings a large “merit order” at a European scale from a reference pricing mechanism being the one of energy traded in Power Exchanges on Day-Ahead.*
- *2° It simplifies TSO cross-border trading by “zoning” the grids as if each EU TSO grid was some type of “national copper plate”; and, by “coupling” the allocation of grid access between these “zoned area copper plate” grids with the merit order built into the PXs in Day-Ahead trading. This is done only after having chosen a guaranteed inter-zonal capacity calculated ex ante (on the same Day-Ahead horizon) by the grid transmission operators (the TSOs).*
- *3° This “Target Model” has its own “last mile” hard task being to open a similar “zones cross-border” process for the shortest time frames (Intraday & Balancing) as to “Europeanise” the last step to power reserve & energy balancing procurement between the TSO grid zones.’*

The network codes and guidelines are developed specifically to smoothly ‘Europeanise’ electricity markets. In this section, first the integration of day-ahead markets will be discussed. Arguably, day-ahead markets are quite well integrated. Overall, we seem to have almost arrived at the ‘last mile’ of the ‘EU Target Model’. Second, the integration of intraday markets is discussed. The integration of intraday markets can be considered as work-in-progress.

5.1 Day-ahead market integration

One of the major accomplishments in the ‘Europeanisation’ of electricity markets is the Price Coupling of Regions (PCR). The PCR is a project of European Power Exchanges to harmonise the European electricity markets. A single price coupling algorithm, called EUPHEMIA (EU + Pan-European Hybrid Electricity Market Integration Algorithm), is used to calculate electricity prices across Europe from Portugal to Estonia. EUPHEMIA algorithm is currently operated with one power exchange per country, except for GB, where two power exchanges participate in the market coupling (ENTSO-E, 2017e). Traded electricity and transmission capacity between bidding zones are allocated simultaneously; this process is called implicit allocation of transmission capacity. The integrated European electricity market is beneficial due to increased liquidity, transparency, efficiency and social welfare. The geographic scope of PCR is shown in Figure 14. For more detailed information about the function of EUPHEMIA, please consult the presentation on PCR (2016a).

In Figure 14 a distinction is made between Multi-Regional Coupling (MRC) and 4M Market Coupling (4 MMC) countries. This is done because at the time of writing, there are two market areas operating under the Price Coupling of Regions model, i.e. the MRC market (19 EU countries in early 2017), which covers virtually the entire European Union except for Central-Eastern and South-Eastern Europe, and

the market of four coupled countries known as 4MMC (Czech Republic, Slovakia, Hungary, Romania). Both areas apply very similar technical solutions which are ultimately to be integrated (TGE, 2015). Furthermore, two countries use the same PCR algorithm for calculating the hourly prices of their day-ahead markets, albeit on an independent basis, namely, Serbia and Switzerland (OMIE, 2015).

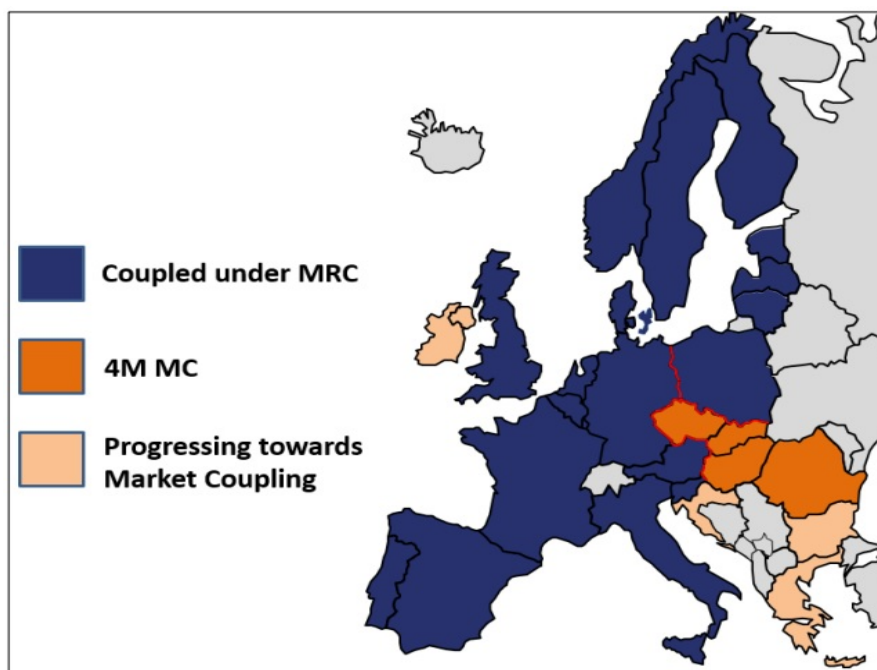


Figure 14: State-of-play in Price Coupling of Regions (PCR) as of February 2017 (ENTSO-E, 2017e)⁵²

The ultimate goal of market coupling is to maximise welfare or economic surplus; this would be achieved through the efficient use of all available resources spread over bidding zones.⁵³ Gains can be made as different countries have a different energy mix and imperfect correlated demand and renewable production. Key to achieving this goal are interconnectors, connecting different bidding zones. Implicit allocation of transmission capacity implies that if there is spare (commercially available) interconnector capacity available between two bidding zones their electricity prices converge.⁵⁴ If not, the maximum exchange possible is the capacity of the congested line, and prices can diverge as markets are 'split'. A price differential between bidding zones during a certain hour results in congestion rent for the TSO(s) or independent party operating the interconnector.^{55,56}

Figure 15 shows the level of price convergence in different regions in the EU, comprising multiple bidding zones.⁵⁷ Different regions show various levels of convergence. No clear trend is visible over the years for most regions. 'The optimal level of price convergence' is very hard to determine, if not

⁵² The red line highlights that borders are not coupled between Austria, Germany, Poland, Slovenia, Czech Republic, Hungary and Slovakia.

⁵³ In the CACM GL (Art. 2(46)) economic surplus is defined as the sum of (i) the supplier surplus for the single day-ahead or intraday coupling for the relevant time period, (ii) the consumer surplus for the single day-ahead or intraday coupling, (iii) the congestion income and (iv) other related costs and benefits where these increase economic efficiency for the relevant time period, supplier and consumer surplus being the difference between the accepted orders and the clearing price per energy unit multiplied by the volume of energy of the orders.

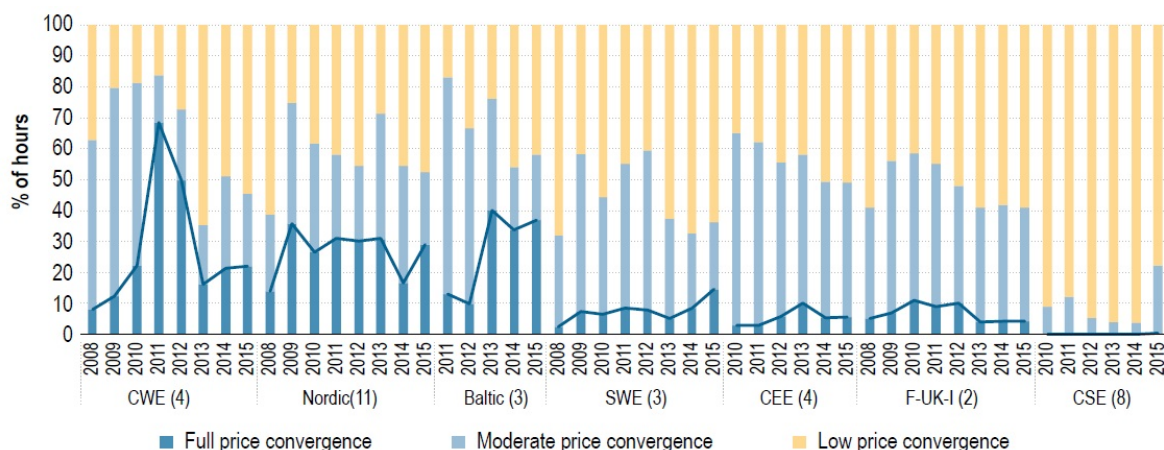
⁵⁴ In more technical terms: no cross-zonal transmission constraint is binding.

⁵⁵ Congestion rent (€/h) = the price differential (€/MWh) x congested capacity of the interconnector (MW)

⁵⁶ For a recent overview of how congestion rent is spent please consult e.g. p.12-14 of ECN et al. (2017)

⁵⁷ Here defined as the % of hours the DAM prices were the same for the different bidding zones within a certain region.

impossible. 100% convergence would mean over-investment in grid infrastructure, very low convergence could imply underinvestment in grids or inefficient use of existing interconnector capacity. The criterion in theory, under ideal assumptions, is that for an optimally developed grid the total congestion income would recover 100% of the total grid investment costs (Pérez-Arriaga et al., 1995). In reality, congestion income covers only a fraction of total grid costs.



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.

Figure 15: DAM price convergence from 2008-2015 (ACER and CEER, 2016)

The following part of this section focuses on the efficient use of cross-zonal transmission capacity. First, explicit and implicit allocation of transmission capacity is described in more detail. Then, methods for the calculation of transmission capacity available for trade are explained. Lastly, unscheduled flows are defined and their origins discussed.

5.1.1 Explicit vs implicit allocation of transmission capacity

There are two market-based arrangements for the (short-term) allocation of cross-zonal transmission capacity: explicit and implicit allocation of transmission capacity.⁵⁸ With explicit trading, transmission capacity and energy are traded separately. Market participants wanting to sell power over a bidding zone border need to acquire the transmission capacity to do so and nominate it. With implicit allocation, electricity and transmission capacity are traded simultaneously. Cross-zonal trade is possible for market participants without explicitly acquiring transmission capacity under the condition that interconnectors are not congested (market coupling). In the PCR for the day-ahead market, implicit allocation is in place, as established in the CACM.

Figure 16 shows how price differentials should be when transmission capacity is efficiently allocated. If the line between country A and B is not congested the price difference between both should be zero (1). However, if the line is congested in the direction of country B (2), then the price in country B should be higher than the price of country A, as electricity should flow from low price areas to high price areas. The exact difference between the price in country A and country B depends on local supply and demand at a certain time. Similarly, if the line is congested in the direction of country A (3), then the price in country A should be higher than the price in country B.

⁵⁸ Kristiansen (2007) explains that there are also non-market based cross-zonal congestion arrangements possible, but these are not in use in the EU anymore.

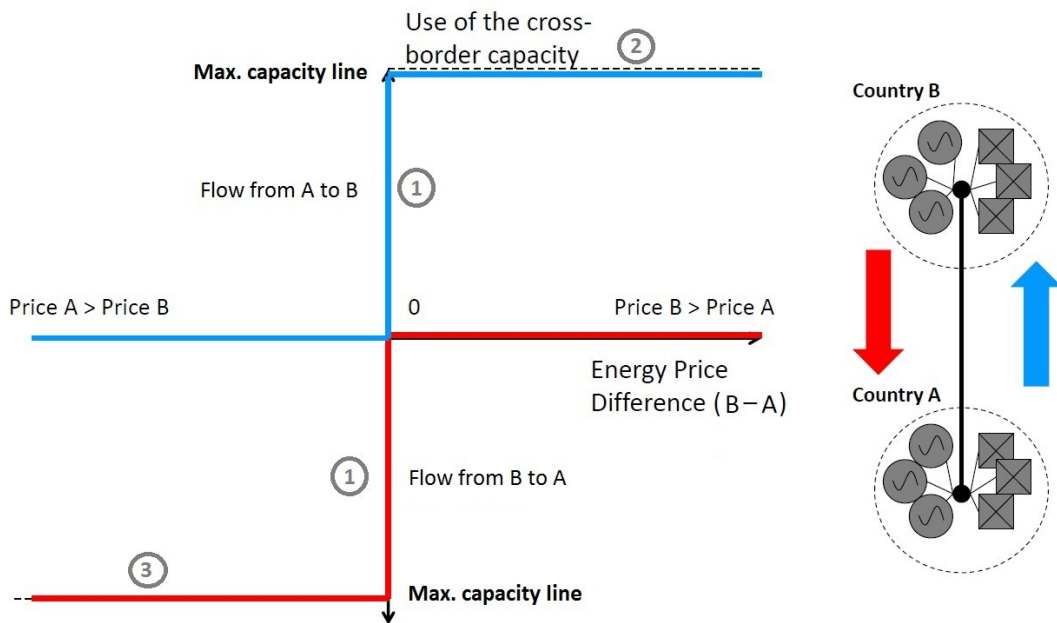
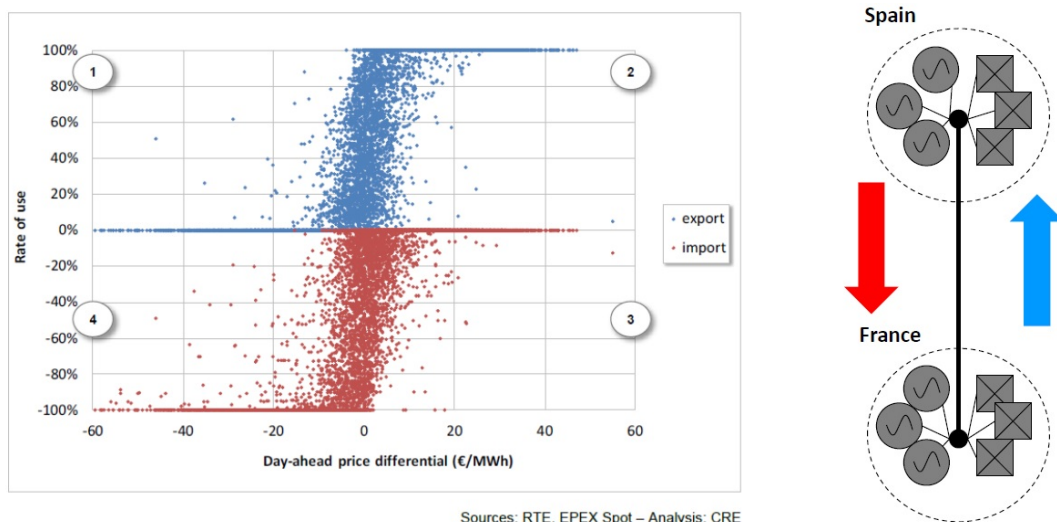


Figure 16: Zonal pricing and optimal cross-zonal allocation (FSR, 2014)

Now, under ideal assumptions, the outcome for explicit allocation and implicit allocation should be the same and optimal (as shown in Figure 16). In Figure 17, results are shown for the French-Spanish border in 2012. At that time, explicit auctions for cross-zonal transmission were held, PCR was not yet in place. The pattern diverges quite strongly from what we would expect with optimal cross-zonal allocation. In some cases, the prices differ between the countries while the interconnector is not congested. Even more extreme, often the price in France was higher, but the electricity was flowing towards Spain (quadrant 1) or vice-versa (quadrant 3). Reasons for the deviation from optimal usage are coordination issues (timing, limited information, imperfect forecast) for market participants or possibly uncompetitive behaviour.



Sources: RTE, EPEX Spot – Analysis: CRE

Figure 17: Explicit cross-zonal allocation: use of net daily capacities on the French-Spanish interconnector compared with hourly DAM price differences, data of 2012 (FSR, 2014)

Figure 18 shows the results for implicit allocation between Belgium and France in 2012. These markets were coupled at the time. It can be seen that with implicit allocation cross-zonal capacity is efficiently used. With implicit allocation, there are no coordination issues.

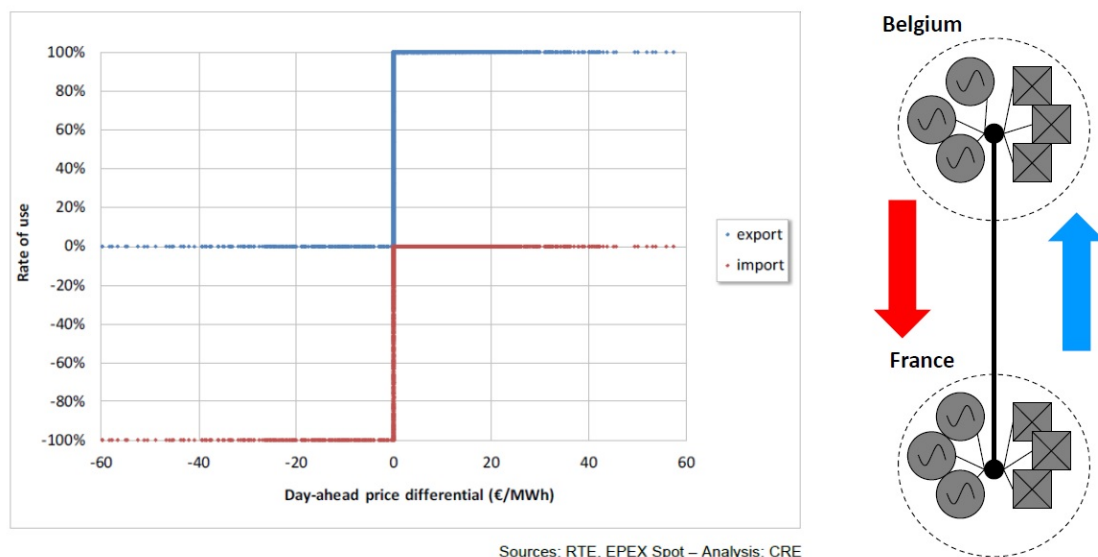


Figure 18: Implicit cross-zonal allocation : use of net daily capacities on the France-Belgium interconnector compared with hourly price differences, data of 2012 (FSR, 2014)

Efficient allocation of available cross-zonal transmission capacity is an important dimension of well-functioning integrated electricity markets. Another crucial dimension is the calculation of the total transmission capacity that should be allocated to market participants. In other words, in this subsection, efficient allocation of cross-zonal capacity was discussed while in the next subsection, the question “how much cross-zonal capacity can be made available for trade without putting the system at risk?” is tackled. Limited available capacity for trade, even when efficiently allocated, does not lead to fully integrated markets.

5.1.2 Cross-zonal capacity calculation: issues and approaches

It is not straightforward to properly calculate the available transmission capacity between bidding zones. The reason for this is that electricity doesn’t flow directly from generators to consumers, but spreads out over a (meshed AC) network according to the laws of physics (Kirchhoff laws). Energy flows across all paths in proportion to their admittance. This implies that one line can be constrained by other lines before reaching its maximal thermal capacity.⁵⁹ Several other issues, directly or indirectly related to the physical nature of electricity and zonal pricing, make it impossible to fully offer the thermal capacity of lines for trade (Nabe and Neuhoﬀ (2015), Schavemaker and Beune (2013) and Van den Bergh et al. (2016)):

- *Calculating cross-zonal capacity for trade is a chicken-and-egg-issue.* Namely, the transmission capacity available for commercial transactions between pricing zones depends on the generation and load pattern within a bidding zone. However, the generation and load pattern within a bidding zone is a function of the market outcome and as such is influenced by the volume of transmission capacity made available by TSOs for cross-zonal trade. This implies that safety margins need to be introduced to compensate for the approximations and simplifications made.
- *Transit flows:* Some cross-zonal capacity of one bidding zone will be used by parallel flows resulting from trade between other bidding zones. For example, trade between Germany and

⁵⁹ For an illustrative example please see Pérez-Arriaga (2013), more precisely section 6.1.3 ‘The Transmission Grid: Technical Considerations’.

France can flow through Belgium. As such, the cross-zonal transmission capacity available for trade between Belgium and its neighbours will be impacted. Transit flows can be unallocated when the exchange causing the flow is cross-zonal and the capacity calculation is not coordinated with the zone facing the flow. If the cross-zonal capacity calculation is coordinated between the zones causing and the zone facing the transit flow, it is called an allocated transit flow (Schavemaker and Beune, 2013).

- **Loop flows:** Transactions within a bidding zone can have an impact on the flows through adjacent bidding zones. For example, if there is a commercial transaction between the North and the South of Germany, it is possible that electricity would flow through Poland to reach its destination. As such, the cross-zonal transmission capacity available for trade between Poland and its neighbours (mostly Germany in this case) will be impacted.

Both loop flows and transit flows are so-called unscheduled flows. With an unscheduled flow the physical flow in the network differs from the scheduled flow. Scheduled flows result from commercial exchanges between consumers and producers within a bidding zone or between two different bidding zones (ACER, 2013).

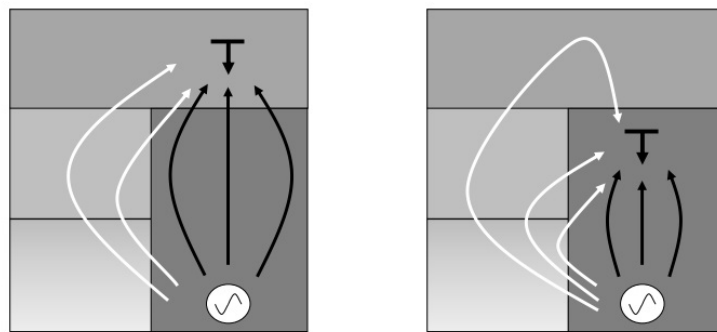


Figure 19: Scheduled flows (black), transit flows (white-left) and loop flows (white-right) (Schavemaker and Beune, 2013)

Today, two methods are in place in Europe to perform the cross-zonal capacity calculation. The conventional coordinated Net Transfer Capacity (NTC) approach or the more sophisticated flow-based approach. The calculation is done by a coordinated capacity calculator per capacity calculation region as explained in Section 2.2.⁶⁰ The CACM says in recital (7) that:

‘There are two permissible approaches when calculating cross-zonal capacity: flow-based or based on coordinated net transmission capacity. The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The flow-based approach should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value.’

Furthermore, in Article 20(2) of CACM it states that ‘no later than 10 months after the approval of the proposal for a capacity calculation region in accordance with Article 15(1), all TSOs in each capacity calculation region shall submit a proposal for a common coordinated capacity calculation methodology

⁶⁰ When they are all in place, RSCs are going to take over this role.

within the respective region. A methodology for both day-ahead and intraday capacity calculation shall be proposed. A delayed submission was permitted with respect to certain CCRs (CACM, Art. 20(3,4)). In the summer of 2017, the TSOs representing the Hansa, CORE, Nordic, Channel, SWE and IU CCRs submitted a proposal for a common coordinated capacity calculation methodology within the respective regions. See Figure 4 (left) for a depiction of these CCRs. At a later point it is intended that the capacity calculation of two or more adjacent CCRs in the same synchronous area shall be integrated if all CCRs implement a flow-based capacity calculation methodology (CACM, Art. 20(5)).

In the remainder of this Subsection, first, the conventional NTC approach is explained. Then, the flow-based approach is described. Lastly, possible remedies are mapped against issues with cross-zonal capacity calculation.

Coordinated Net Transfer Capacity (NTC) approach

In the literature, the approach used to calculate NTC values is denominated the Available Transfer Capacity (ATC) approach (Plancke et al., 2016; Van den Bergh et al., 2016). Van den Bergh et al. (2016) explain that in the ATC approach the link between the physical network and commercial transactions is heavily simplified. Bidding zones are represented by one equivalent node, and only cross-zonal links are considered as shown in Figure 20 (left) for three bidding zones.

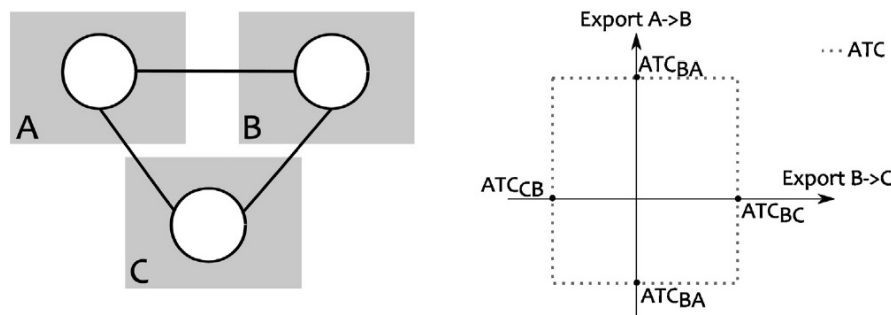


Figure 20: Grid model under the ATC approach (left) and flow domain (right) (Van den Bergh et al., 2016)

With ATC, the cross-zonal capacity offered for one link (the so-called ATC value) is independent of the flows on other cross-zonal links as can be seen in Figure 20 (right). TSOs use a heuristic to calculate the cross-zonal capacity available for trade based on assumptions of the market outcome (2-days ahead) and associated physical flows. As such, capacity allocation takes place *ex ante*, completely separated, from the market clearing.

At the time of writing, the ATC approach is used in European markets, except for Central-West Europe, where flow-based market coupling was introduced in May 2015 (ACER and CEER, 2016). Van den Bergh et al. (2016) add: *'given the strong assumptions inherent to the ATC method, the ATC value needs to be conservative to avoid overloading physical lines.'* The ATC approach is compatible with both explicit and implicit allocation of transmission capacity.

Flow-based (FB) approach

In contrast, the FB approach is only compatible with implicit allocation of cross-zonal transmission capacity or market coupling; hence, the method is often also directly called flow-based market coupling (FBMC). In FBMC, although still simplified, more physical transmission constraints are taken into account in the market clearing. Plancke et al. (2016) explain that to arrive at the simplified network

model without having to consider all individual lines, each TSO defines Critical Network Elements (CNEs) for its control area. CNEs are also called Critical Branches in the literature and include cross-zonal lines, but can also include internal lines or transformers that are significantly impacted by cross-zonal exchanges.

It can be said that with FBMC the cross-zonal capacity allocation happens partly ex ante and partly simultaneously with the market clearing as the (simplified) transmission constraints are taken into account in the market clearing. In other words, there is an interaction between cross-zonal capacity allocation and market clearing. In Figure 21 (left) a simplified representation of a grid model under FBMC is shown. In the calculation, cross-zonal lines are considered together with internal critical network elements.

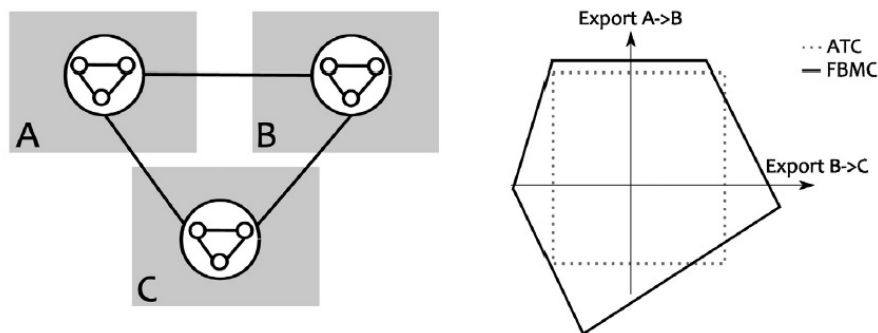


Figure 21: Grid model under FB approach (left) and flow domain (Van den Bergh et al., 2016)

Combining all main inputs from the TSOs and flow equations, a feasible FB trading domain is obtained as shown in Figure 21 (right). With FBMC, the cross-zonal capacity offered to the market on one line is no longer independent from other cross-zonal flows. Actually, in the FB approach, the entire (in most cases larger) flow domain is offered to the market. In contrast to the ATC approach, with the FB approach the market, driven by bids and offers, decides on the allocation of transmission capacity among market participants.

As stated before, with FBMC cross-zonal capacity allocation happens partly ex ante and partly simultaneously with market clearing. In the previous paragraph, the simultaneous part was discussed. The ex ante part refers to the main inputs from TSOs which are combined on a regional level and needed to determine the flow domain. The FBMC is a process, not a one-step calculation, which starts two days before real-time ('Base Case') and ends the morning one day ahead. At that moment, the coordinated capacity calculators deliver the necessary parameters to the NEMO who is in charge of the day-ahead market clearing algorithm. The FB-parameters incorporated in the market clearing algorithm are challenging to determine (Plancke et al., 2016; Van den Bergh et al., 2016).⁶¹ They consist of:

- *Zonal Power Transfer Distribution Factors (PTDFs):*

⁶¹ For transparency reasons, the way they are determined should be described in detail in the capacity calculation methodology per CCR (CACM, Art. 21(1)). This was already the case for the CWE FBMC, this data is published on the website of the JAO (www.jao.eu -> Support-> CWE FBMC).

- **What?** Zonal PTDFs describe the linear relationship between the physical flow in a critical branch and the net exchange position of a specific bidding zone.⁶² They are formulated in a (sparse) matrix form with on one dimension all the bidding zones and on the other dimension all the cross-zonal interconnectors.
- **How are they derived?** With zonal pricing, nodes are grouped per zone. This implies that in order to correctly represent flows between zones, zonal PTDFs need to be approximated from what happens at nodal level within a zone. Generation Shift Keys (GSKs) 'translate' changes in generation/consumption at nodal level to impacts on the net exchange level of a zone. GSKs are not easy to determine as they are based on predictions of the market outcome and subject to forecast errors. Each TSO calculates the GSKs for his control area. Van den Bergh et al. (2016) describe that the way TSOs derived GSKs in the past was not harmonised. The CACM establishes in Article 24 that the common capacity calculation methodology (per capacity calculation regions) shall include a proposal for a methodology to determine a common way to derive generation shift keys for each bidding zone. Additionally, the common grid model plays a crucial role in obtaining optimal forecast to increase the accuracy of GSKs.
- *Available Margins (AM) on Critical Network elements (CNE):*
 - **What?** The AM is the maximal flow (a fraction of the thermal limit) that can be carried by CNEs due to flows induced by day-ahead trade. In the literature, the Available Margin is also referred to as the Remaining Available Margin (RAM).
 - **How are they derived?** The determination of 1.) what the critical network elements are within a control zone and 2.) the contingencies (critical outages) to be considered for system security are key for the determination of this FB-parameter. Van den Bergh et al. (2016) find that the exact method to derive the AM is confusing and inconsistently formulated in consulted FBMC reports. In general, AM are derived as the maximal flow an element can carry minus 3 flows:
 - The Reference Flow on a CNE: the reference flow is caused by transactions between or within bidding zones other than the DA market, such bilateral transactions or transactions in forward markets.
 - A Final Adjustment value: a margin which is TSO specific and depends on, for example, complex remedial actions. To determinate this value it is important to ensure that there is no discrimination between internal and cross-zonal flows (CACM, Art. 29(7)(d)).
 - A Flow Reliability Margin: a safety margin compensating for approximations made in the FB-approach

Also, regarding the calculation of the AM and its components, the CACM tends to create transparency and harmonisation with Article 29.

Van den Bergh et al. (2016) state that by better representing the physical characteristics with the FB approach, the cross-zonal capacity offered to the market can be determined in a less conservative way. Plancke et al. (2016) agree that the FB is more sophisticated than the ATC approach, resulting in (theoretically) higher cross-zonal capacity offered to the market. However, the authors add that operational challenges could arise due to the increased complexity.

⁶² The net exchange position of a bidding zone is equal to the total production within the zone minus the total consumption within a zone. If the production is higher than the consumption, the zone will be a net exporter. Vice-versa the zone would be a net importer.

Limited commercial cross-zonal capacity: causes and issues

ACER and CEER (2017, 2016) find in their Market Monitoring Report (MMR) that, in recent years, the volume of tradable cross-zonal capacities in the EU has remained relatively limited. Improvement was anticipated after investments in transmission networks were made and some progress in capacity calculation methods was seen. Important variation between regions are found, but on most EU borders only a small proportion of the physical capacity is offered to the market. The MMR analysis shows that on average 84% of HVDC and 28% of HVAC interconnector's thermal capacity was used for trading in 2015 (ACER and CEER, 2016).

However, the thermal capacity of a line is not the best metric to assess whether a reasonable proportion of the capacity is offered to the market. Therefore a new metric is introduced in the latest ACER and CEER MMR of 2016, published in 2017.⁶³ This new metric, called 'the benchmark capacity', is the maximum capacity that could be made available to the market on a given border if the recent Agency's Recommendation on capacity calculation were to be followed.⁶⁴ What this means is that i) cross-zonal capacity is only limited by cross-zonal network elements and that ii) the full capacity of these network elements is fully available for cross-zonal exchanges. In other words, it is assumed that no internal flows or loop flows are prioritised over offering cross-zonal capacity for trade; the remaining congestion within bidding zones is assumed to be addressed via remedial actions. Additionally, it assumed that the thermal capacity of all individual cross-zonal network elements is reduced by 15% to cope with uncertainty (RM) and with a residual amount of UFs that would remain in any 'close-to-ideal' configuration of bidding zones. Furthermore, the methodology for calculating benchmark capacity respects the N-1 security criterion. Lastly, the methodology requires that the values of benchmark capacity on different borders must be simultaneously feasible.⁶⁵

The results of the ACER and CEER assessment for 2016 show that an average of 47% of the HVAC benchmark capacity was made available for trading, showing considerable room for improvement. As expected, the share of the benchmark capacity made available for trading was much higher (over 85% on average) for HVDC interconnectors. The results for different regions are shown in Figure 22.

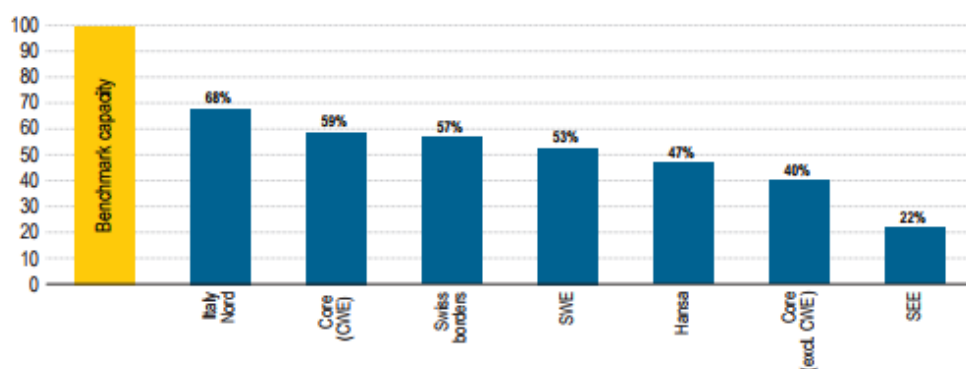


Figure 22: Ratio between the available cross-border capacity for trade and the benchmark capacity of HVAC interconnectors per region in 2016 (ACER and CEER, 2017)

⁶³ If 100% of the physical capacity of an HVAC line would be offered to the market, it would mean that: no margin for security is foreseen, the network is perfectly built (no 'bottlenecks' due to Kirchhoff's laws) and bidding zones are perfectly demarcated.

⁶⁴ This is the Recommendation of the Agency No 02/2016 of 11 November 2016 (ACER, 2016b).

⁶⁵ For a more detailed explanation of the methodology to calculate benchmark capacities for cross-zonal exchange, please consult Annex 2 of ACER and CEER (2017).

A first reason described in ACER and CEER (2016,2017) which could explain the low utilisation rates of cross-zonal capacity is a lack of coordination between TSOs concerning the cross-zonal capacity calculation. For 40 out of 48 assessed borders, either a bilateral or partly coordinated capacity calculation method is applied (ACER and CEER (2016)). Additionally, on many borders during certain market time frames, capacity calculation is simply not applied by at least one of the TSOs. The CACM is tackling this issue by establishing coordinated capacity regions (CACM, Art. 15(1)) and demanding a common capacity calculation methodology per CCR (Art. 20(2)). Also, by 31 December 2020, all regions shall use a harmonised capacity calculation methodology, which is described in more detail in Article 21(4) of the CACM.

A second reason explaining the low utilisation rates of cross-zonal transmission capacity, stated in the same reports, is the controversial claim 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. It is hard to prove that TSOs demonstrate such behaviour. Glachant and Pignon (2005) demonstrate, using a theoretical example, that such behaviour could be both feasible and would necessitate only a slight manipulation of the data. In the CACM, it is clearly stated that internal and cross-zonal flows should be treated equally. More precisely, it is stated that there should be no undue discrimination between internal and cross-zonal flows. In Article 23 of the CACM it is written that:⁶⁶

(1) Each TSO shall respect the operational security limits and contingencies used in operational security analysis.

(2) If the operational security limits and contingencies used in capacity calculation are not the same as those used in operational security analysis, TSOs shall describe in the proposal for the common capacity calculation methodology the particular method and criteria they have used to determine the operational security limits and contingencies used for capacity calculation.

***(3) If TSOs apply allocation constraints, they can only be determined using:*⁶⁷**

(a) constraints that are needed to maintain the transmission system within operational security limits and that cannot be transformed efficiently into maximum flows on critical network elements; or

(b) constraints intended to increase the economic surplus for single day-ahead or intraday coupling.

⁶⁶ ACER (2016) repeats point 3 of Article 23 of CACM in their recommendation on the common capacity calculation and redispatch and countertrading cost sharing methodologies to not take into account internal congestion when calculating cross-zonal capacity (it should in principle be resolved with remedial actions in the short term and other solutions in the long term), except temporarily, if:

(a) it is needed to ensure operational security; and

(b) it is economically more efficient than other available remedies (taking into account the EU-wide welfare effects of the reduction of cross-zonal capacity) and minimises the negative impacts on the internal market in electricity.

⁶⁷ Allocation constraints are defined in the CACM (Art. 2(6)) as the constraints to be respected during capacity allocation to maintain the transmission system within operational security limits and which have not been translated into cross-zonal capacity or are needed to increase the efficiency of capacity allocation;

Next to increased coordination between TSOs and equal treatment of internal and cross-zonal flows, there are other issues directly related to zonal pricing, the (mainly political) choice made in the EU Target Model.⁶⁸

5.2 Intraday market integration

The Target Model for the intraday market has been laid down in the CACM and is based on continuous trading where cross-zonal transmission capacity is allocated through implicit continuous allocation. Implicit allocation implies that the common IT system will accommodate the continuous matching of bids and orders from market participants in one bidding zone with bids and orders coming from its own bidding zone and from any other bidding zone while cross-zonal capacity is still available. By integrating intraday markets, the opportunities for market parties to trade close to real-time can be significantly increased as they also can benefit from the available liquidity in other zones next to their bidding zone, which increases matching probabilities. This initiative is called the Cross-Border Intraday Market Project (XBID). Currently, the XBID project is comprised of members from 15 European countries, as illustrated in Figure 23. Accession countries are future members of the XBID project. The complex XBID project is a work-in-progress and plans to go live in the beginning of 2018.⁶⁹

XBID will not only support implicit continuous intraday trading but also explicit intraday cross-zonal allocation of transmission capacity. Both are in line with the CACM. More precisely, Article 64 says that:

‘Where jointly requested by the regulatory authorities of the Member States of each of the bidding zone borders concerned, the TSOs concerned shall also provide explicit allocation, in addition to implicit allocation, that is to say, capacity allocation separate from the electricity trade, via the capacity management module on bidding zone borders.’

However, explicit allocation of cross-zonal transmission capacity is only transitional as implied by Article 65, titled ‘Removal of explicit allocation’. More precisely:

‘The NEMOs concerned shall cooperate closely with the TSOs concerned and shall consult market participants in order to translate the needs of market participants linked to explicit capacity allocation rights into non-standard intraday products.’⁷⁰

⁶⁸ The reasons the EU Target Model chose for zonal pricing over nodal pricing (applied in several parts of the US) is beyond the scope of this report.

⁶⁹ As stated on the website of Nord Pool AS, link <https://www.nordpoolgroup.com/TAS/intraday-trading/intraday-upgrade/> consulted on 22/12/’17.

⁷⁰ Non-standard intraday products offered through implicit allocation.

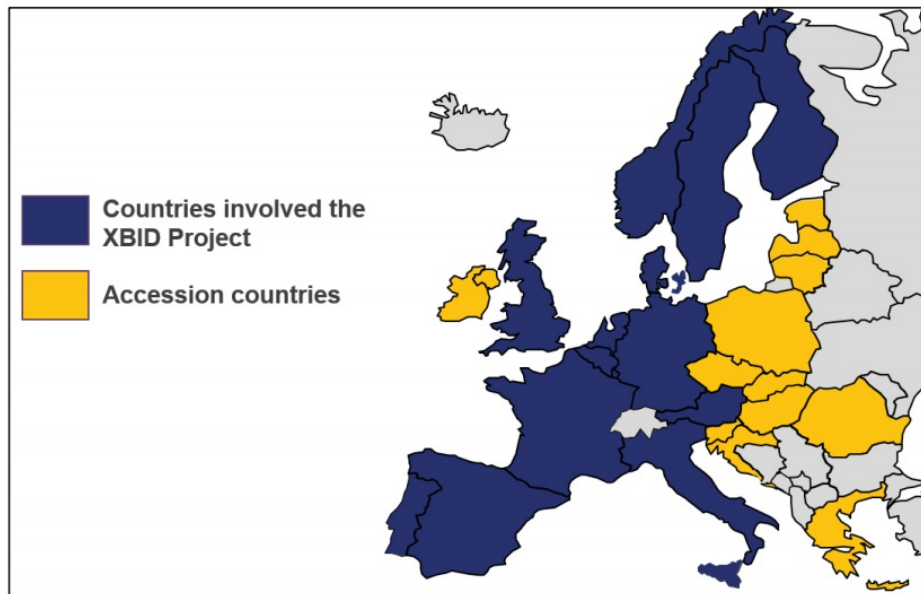


Figure 23: State-of-play of XBID as of February 2017 (ENTSO-E, 2017e)

A major difference between the DAM integration and IDM integration is the fact that the former is based on ‘coupling’ auctions of bidding zones (single merit order if no transmission constraints are present), while the latter is based on ‘merging’ order books for continuous trading. It is generally agreed that it is more straightforward to efficiently allocate cross-zonal capacity with auctions. The pros and cons of auctions vs continuous trading have already been discussed in Section 4.3.1. In this section, the implications for the allocation of cross-zonal capacity of both options are further elaborated on.

5.2.1 Integration with continuous trading

Bellenbaum et al. (2014) describe in their paper six methods to allocate cross-zonal capacity in the intraday market frame. Three methods are based on continuous trading, two on auctions and one hybrid method combining both.

In this Subsection we focus only on one method based on continuous trading, namely, continuous cross-zonal trading with implicit allocation of cross-zonal transmission capacity. This method will be in place when the XBID goes live. Trading is based on an order book and is possible every day around the clock until intraday gate closure, e.g. one hour before delivery. Bids are continuously matched, disregarding the time of order placement, and cross-zonal capacities (calculated using the NTC approach) are automatically updated after each executed trade. Two problems arise with this method:

1.) *No market-based allocation of cross-zonal transmission capacity:* Transmission capacity is allocated on a first-come-first-serve and is not priced. Neuhoff et al. (2016a) explain that the first mover receives the potential scarcity value of transmission capacity. In short, this allocation favours quick trades, rather than efficient ones. Pricing of transmission capacity could be introduced within this method: capacity prices could be administratively set ex ante or ex post or through explicit auctions. Both approaches introduce inefficiencies.

2.) *Suboptimal calculation of available cross-zonal transmission capacity:* It is impossible to apply a flow-based capacity calculation approach with continuous trading. This implies that TSOs, not the

market, will repartition ex ante available cross-zonal capacity over borders. As a result, less cross-zonal capacity might be offered by the market.

5.2.2 Continuous trading complemented with (regional) intraday auctions

As previously mentioned, the CACM (Art. 63) also allows for regional auctions complementing continuous intraday trade if requested by the relevant NEMOs and TSOs on bidding zone borders. Furthermore, it is stated that continuous trading may be stopped for a limited period of time to hold the auction.

With intraday auctions (IDAs), the two problems mentioned with continuous intraday trading could be resolved. CACM requests that intraday cross-zonal capacity should be priced efficiently and reflect market congestion, based on actual orders (ENTSO-E, 2017f). In the proposal by all TSOs for a single methodology for pricing intraday cross-zonal capacity that was submitted for public consultation in April 2017, it is stated that it is not possible to efficiently price intraday cross-zonal capacity solely with continuous trading. Therefore, a hybrid model is proposed in which continuous trading is combined with IDAs. On 10 August 2017 an updated proposal was submitted by all TSOs to all NRAs and the Agency (ENTSO-E, 2017g).

The proposal of April 2017 put forward that at least two Pan-European intraday auctions are held, one initial IDA on the day before delivery (D-1) and one on the day of delivery. The auction on day D-1 shall contain MTUs of the day of delivery. The other auction, held on the day of delivery, contains all MTUs from its first delivery hour until the end of day D. In the updated proposal of August 2017 only one IDA was kept, the IDA held at D-1 for all MTUs of day D with a deadline for bid submission at 22:00. In capacity calculation regions where the intraday cross-zonal gate opening time is set up to be before the IDA at 22:00, regional cross-zonal opening auctions may be held before the IDA. The within-day (D) auction has been removed. However, it is signalled that once further details of the intraday capacity become available, the introduction of the within-day IDAs shall be reassessed. In those proposals, it is stated that cross-zonal intraday capacity for all market time units (MTUs) shall be initially offered to an IDA. The initial IDA will therefore price the initial intraday cross-zonal capacity calculated by the TSOs. In case offered cross-zonal intraday capacity does not get allocated within the respective IDA, it will be offered through the subsequent continuous trading.

Neuhoff et al. (2016a) describe an additional benefit of intraday auctions in this context. They state that intraday auctions allow TSOs to reduce the capacity made available before by repurchasing cross-zonal transmission capacity. This additional flexibility allows for a less conservative provision of commercial transmission capacity.

However, it is not so clear-cut how cross-zonal capacity would be optimally divided between continuous trading and the intraday auctions. Avoiding gaming between both trading remains a concern as during continuous implicit trading there would be no capacity price, while in an implicit auction a capacity price could be determined based on energy price differences. Also, the integration of intraday-auctions requires a cross-zonal consensus on the optimal frequency and exact timing of regional or national intraday auctions. If those are not aligned, efficient integration is not possible. Lastly, there are concerns regarding the impact of complementary auctions on the liquidity in continuous trading. In many countries, intraday markets are only just emerging and it is argued that splitting liquidity between auctions and continuous trading could impede this development.

6. Establishing national balancing markets

In a power system, demand should equal supply at all times. In more technical terms, the system frequency must be maintained close to its nominal value (50 Hz in Europe). If the system frequency deviates significantly, generators can trip off (to protect it from damage) which in itself causes further frequency deviation, thus a cascade of generation tripping off the system can occur. This is what is meant by a ‘system collapse’, and it can result in a widespread blackout. Each TSO is responsible for the real-time balance in its control area to avoid such a collapse, and the balancing mechanism is in place to manage this process. At the time of writing, the organisation of the balancing mechanism (incl. balancing markets) is not harmonised in the EU.

Two network codes aim to support the harmonisation of balancing and are of particular importance in this chapter: the EBGL and the SOGL. The EBGL is primarily intended to harmonise market arrangements related to balancing: the design of balancing markets and the imbalance settlement mechanism.⁷¹ However, as balancing happens in real-time, balancing market arrangements cannot be fully decoupled from system operation and security. Therefore, the SOGL is also relevant for this chapter. The SOGL primarily addresses three other aspects of balancing: the harmonisation of reserve categories, the activation strategy for balancing energy in real-time and the sizing of reserves.

The SOGL defines four types of reserve products which can be grouped under three processes. The reserve categories are Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). Previously, different denominations existed. To avoid confusion, frequently used terms are summarised in Table 1.

	Frequency containment process	Frequency restoration process		Reserve replacement process
Operational reserves defined by SOGL	Frequency Containment Reserve (FCR)	Automatic Frequency Restoration Reserves (aFRR)	Manual Frequency Restoration Reserves (mFRR)	Replacement Reserve (RR)
ENTSO-E CE Operation handbook	Primary Control	Secondary Control	Tertiary Control	Tertiary Control

Table 1: Terminology for reserve products (based on E-Bridge consulting GmbH and IAEW, 2014)

These types of reserves meet different operational needs, in practical terms they differ mainly in response time and maximum duration of delivery. The activation of different reserves after a frequency drop/spike are shown in Figure 24.^{72,73} From the moment the frequency drops/spikes, FCR is almost instantaneously activated to stabilise the drop/spike. FCR are the fastest types of reserves

⁷¹ Balancing services are also often referred to as ancillary services for frequency control. Examples of ancillary services for non-frequency control (grid services) are voltage support and congestion management.

⁷² A frequency drop is due to a deficit of energy in the system finding its cause in more consumption or less generation than scheduled in real-time. Vice-versa, frequency would rise. In the EBGL terminology: the aggregate of the (contractual) positions, meaning the declared energy volume of a balance responsible party (BRP) to the TSO at intraday gate closure, is lower than the total located volume attributed to the BRPs. The allocated volume means an energy volume physically injected/withdrawn from the system and attributed to a BRP. A BRP is a market party or its representative responsible for imbalances. A BRP can be an individual generator or industrial consumer connected to the transmission grid or a portfolio of generators/consumers (balancing groups).

⁷³ It should be noted that the activation process shown in this Figure is the typical activation process for a TSO with a reactive approach to the activation of balancing energy. This concept is further explained in Section 6.4

and operated using a joint process involving all TSOs of the synchronous area, as described in Section 2.3. Within a couple of minutes, the frequency restoration process (FRP) starts. First, aFRR and later mFRR are activated. aFRR are reserves activated automatically by a controller operated by the TSO, mFRR are activated upon a specific manual request from the TSO. FRR aims to restore the frequency to its nominal value. In more technical terms, the frequency restoration control error (FRCE) is regulated towards zero. Finally, after about 15 minutes or more, RR, the slowest type of reserves, can be activated to support or replace FRR. Not all systems have RR as this process is not made mandatory by the SOGL.

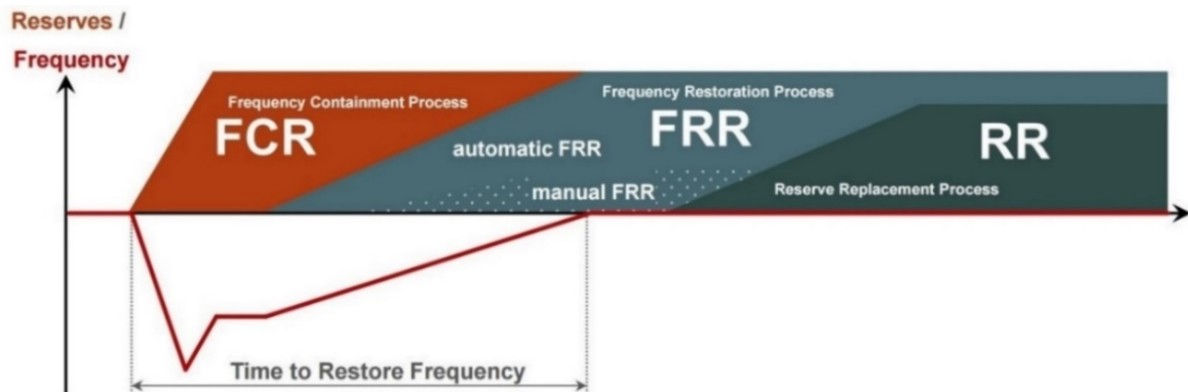


Figure 24: A frequency drop and the reserve activation structure (Elia and TenneT, 2014) ⁷⁴

Although the same categories of reserve products exist in the EU, the exact product definition and the methodologies used for sizing or activation can still differ strongly from one control area to another. Also, the way balancing resources are procured in balancing markets can differ and the exact working of imbalance settlement mechanism can vary. These aspects are discussed in the following sections, which are structured to reflect the four building blocks of the balancing mechanism as displayed in Figure 25.

⁷⁴ Inertia as the first source of energy limiting frequency drop is not depicted in the Figure. Inertia is an inherent physical property of e.g. turbines. Inertia slows down a frequency drop/spike immediately after a mismatch of supply and demand and does not need any control signal. In other words, with little inertia a small difference in supply and demand can cause a large direct frequency drop/spike. Inertia was always valuable for the system, but as it was abundant in the recent past it was mostly provided for free. Now with DER penetration and particular times during which not many thermal power plants are connected, system inertia and thus reliability decreases. This is especially a concern for isolated systems. To limit such issues there are also methods being developed to obtain inertia from other sources than thermal plants, e.g. by energy storage (so-called 'synthetic inertia provision') as discussed in Delille et al. (2012).

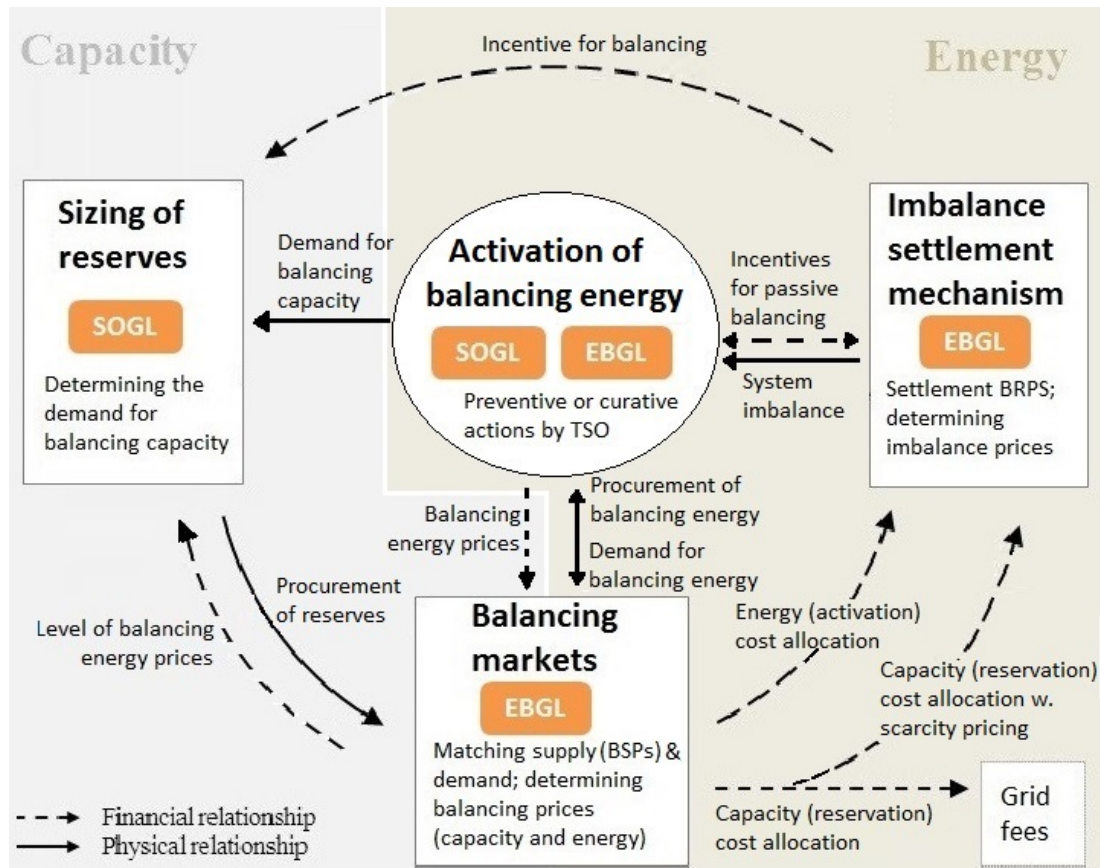


Figure 25: The four building blocks of the balancing mechanism, financial and physical relationships and relevant network codes (adapted from Hirth and Ziegenhagen, 2015)

The different building blocks are financially or physically interlinked. The design of different blocks is covered by network codes EBGL and/or SOGL. It should be noted that the way balancing mechanisms are designed strongly influences trade in other short-term markets, e.g. high imbalance prices encourage rebalancing by trading in the intraday market or high reserve requirements can reduce the supply in short-term markets. The EBGL and SOGL also outline how to integrate balancing markets; this topic falls out of the scope of this chapter and is picked up in the next chapter.

6.1 Reserve sizing

Sizing of reserves is an exercise done by TSOs. The amount of balancing capacity needed is a function of:

- The expected system imbalances in real-time. The more BRPs are incentivised (high real-time imbalance prices) or able (adequate market design of and liquidity in the intraday and day-ahead market) to balance their positions, the less reserve capacity is required.
- The amount of non-contracted flexibility available in real-time: the more generation/demand is available simply in response to high balancing energy prices, the less need for capacity reservation.
- The activation strategy of the TSO: the more a TSO makes use of preventive actions, the higher the volume of activated energy and the greater the need for reserved capacity.

The way reserve sizing is conducted determines the demand and frequency of balancing capacity markets, which in its turn can create barriers to certain technologies' participation in these markets.

Hirth and Ziegenhagen (2015) describe that, broadly, TSOs can apply two methods for reserve sizing: static or dynamic sizing. Static sizing implies that reserves are acquired for long periods, such as a month or a year, while with dynamic sizing the reserve requirements are more frequently updated and have a stronger link with the actual state of the system. In general, static reserves are mostly calculated using a deterministic approach (e.g. ‘the worst-case event’, N-1 procedure) and dynamic reserves using a probabilistic approach (e.g. probability density functions of events and correlations).

It is argued by Hirth and Ziegenhagen (2015); Just and Weber (2015); Neuhoff et al. (2015a) that countries with high shares of vRES need to allow for short-term procurement of reserves to lower the entry barriers for these generation assets to participate in the balancing capacity market. The same holds true for demand response. Unlike conventional generation, whose bids will vary as a function of variable running costs which are relatively stable and predictable over longer periods of time, renewable generators’ and demand response resources’ bids are primarily based on opportunity costs rather than direct ones. Shorter-term procurement will make it easier for these market parties to correctly estimate their opportunity cost to bid in the balancing capacity market, which should lead to a better allocation of resources across the system as a whole. Brijs et al. (2017) add that there is less uncertainty of vRES or DR resources’ availability with shorter time periods. This availability risk can also be (partly) mitigated by splitting the total procured volume into shorter blocks which are procured separately. Finally, by holding more frequent auctions for shorter time periods, the need for balancing capacity could be lowered, leading to efficiency gains. Daily auctions with a contract duration of one hour are proposed by Hirth and Ziegenhagen (2015), similar to day-ahead spot auctions. This setup is already used in Nordic and some Eastern European countries (ENTSO-E, 2015c).

However, TSOs are reluctant to move to shorter time periods, as they are concerned that the risk of failing to contract their reserve requirements increases with a shorter window in which to source reserves. TSOs can have some reservations about a dynamic, daily adjusted procurement volume since this requires an additional probabilistic assessment of the forecast errors and ramps of the next day. Nabe and Neuhoff (2015) state that *‘TSOs have the incentive to be “on the very safe side” since they do not benefit from lower prices of reserves but would be accounted for insufficient reserve procurement.’*⁷⁵ Brijs et al. (2017) note that an argument in favour of longer contract periods might be that they make it easier to finance investments in flexibility.

Sizing of reserves is mainly covered by the SOGL. The dimensioning rules for FCR, FRR and RR are described in Article 153, 157 and 160 of the SOGL, respectively. In summary, it is outlined that:

- FCR
 - Should be dimensioned at least on an annual basis
 - The geographic scale of dimensioning is the synchronous area
 - The dimensioning rule shall take into account a reference incident (3000 MW in positive and negative direction in CE)

⁷⁵ This statement does not always hold. For example, in GB there is a NRA approved incentive scheme for the TSO that rewards the TSO financially for reducing the costs to consumers – they share in the benefit and conversely share in any over-procurement costs. This aims to align the TSO with the interests of the customer if the incentive is designed correctly. For more details, see e.g. ‘System Operator Incentives’, link: <https://www.ofgem.gov.uk/gas/wholesale-market/market-efficiency-review-and-reform/system-operator-incentives> consulted on 22/12/2017.

- CE and Nordic synchronous area have the right to (additionally) define a probabilistic approach.
- Each TSO has an FCR requirement proportional to the net generation and consumption in its control area.
- FRR
 - The geographic scale of dimensioning is the LFC Block
 - A probabilistic approach should be applied using historical data
 - Per LFC Block the TSOs will determine the ratio of aFRR over mFRR
 - The FRR procured shall not be less than the dimensioning incident and cover all imbalances (based on the probabilistic assessment) for at least 99% of the time in its respective direction (positive or negative).⁷⁶
- RR
 - The geographic scale of dimensioning is the LFC Block
 - If procured, the dimensioning process should be done jointly with FRR
 - If procured, in the CE and Nordic synchronous area there should be enough positive/negative RR to restore positive/negative FRR.
 - If procured, in the GB and IE/NI synchronous area there should be enough positive/negative RR to restore positive/negative FRR and FCR.

Additionally, the EBGL sets out high-level principles regarding the procurement of FRR and RR in balancing capacity markets, which cannot be decoupled from reserve sizing. In Article 32(2) it is stated that:

- (a) the procurement method [of balancing capacity] shall be market-based for at least the frequency restoration reserves and the replacement reserves;*
- (b) the procurement process shall be performed on a short-term basis to the extent possible and where economically efficient;*
- (c) the contracted volume may be divided into several contracting periods.*

But procuring reserves closer to real-time and dividing the contracted volume into several contracting periods is not enough to allow vRES and DR to participate in balancing capacity markets. Technical requirements and the prequalification process for reserve products also impact balancing capacity market entry barriers.⁷⁷ Other parameters of the balancing capacity market which are more market design related are discussed in the next section.

6.2 The balancing markets: capacity and energy

The TSO organises and is the single buyer on the balancing capacity and balancing energy markets. On the supply side, balancing service providers (BSPs), market participants with reserve-providing units or reserve-providing groups, offer balancing services to TSOs. The amount of balancing capacity procured is determined by the balancing reserve requirement. The amount of balancing energy activated depends on system imbalances. The activation strategy of balancing energy can influence the demand

⁷⁶ A dimensioning incident is defined in SOGL Art. 157(2.d) as ‘the largest imbalance that may result from an instantaneous change of active power of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line within the LFC Block.’ A dimensioning incident is determined both in the negative (deficit of energy) and positive (excess of energy) direction.

⁷⁷ Technical minimum requirements and the prequalification process of FCR, FRR and RR are described in Art. 154 and 155 for FCR, Art. 158 and 159 for FRR and Art. 161 and 162 for RR in the SOGL. Additionally, for FCR details regarding the exact provision are given in Art. 156 of the SOGL.

for balancing energy and prices. It is not an understatement to say that balancing markets are not harmonised in the EU today (AGORA, 2016; Brijs et al., 2017). EBGL outlines market design rules to allow for harmonisation.

In this section, firstly the balancing capacity market and its key design parameters are described. After, the balancing energy market and its market design parameters are introduced.

Box 4: The participation of resources connected to the distribution grid in balancing markets and the power of the DSO

In recital (8) of the EBGL it is declared that a level-playing field should be in place for all market participants, including demand-response aggregators and assets located at the distribution level, to offer balancing services and ensure adequate competition.

The SOGL specifies in Art. 182(3) that the prequalification process for balancing resources connected to the distribution level shall rely on rules concerning information exchanges and the delivery of active power reserves between the TSO, the reserve-connecting DSO and the intermediate DSOs⁷⁸. Each reserve-connecting DSO and each intermediate DSO, in cooperation with the TSO, shall have the right to set limits to or exclude the delivery of active power reserves located in the distribution system during the prequalification process. Reasons for limitations or exclusion should be technical, such as the geographical location of the reserve providing units and reserve providing groups (SOGL, Art. 182(4)).

Further, each reserve-connecting DSO and each intermediate DSO can set temporary limits to the delivery of active power reserves before their activation. Procedures need to be agreed upon with the respective TSO (SOGL, Art. 182(5)). It is not decided yet to whom the costs of such an action should be allocated. In Art. 15(3) of the EBGL it is stated that each TSO may, together with the reserve-connecting DSOs within the TSO's control area, jointly elaborate a methodology for allocating costs resulting from the exclusion or curtailment of active reserves connected to the distribution level.

6.2.1 Balancing capacity market and its key market design parameters

Balancing capacity is defined as a volume of reserve capacity that a BSP has agreed to bid in the balancing energy market for the duration of the contract. This implies that a BSP cannot commit this capacity in preceding markets. In the balancing capacity market, BSPs offer upward or downward balancing capacity with certain product characteristics to the TSO.⁷⁹ In general, there are different markets for the different reserve products procured in a market-based way (possibly FCR, aFRR, mFRR and, if procured, RR). The demand for reserves procured in the balancing capacity market is determined in the reserve sizing process, described previously, and these two building blocks of the balancing mechanism cannot be fully decoupled. There are many market design parameters which can differ from one balancing capacity market to another, for a full and recent overview please consult ENTSO-E (2017h). Two key differentiators touched upon previously are:

⁷⁸ No formal definition of 'intermediate DSO' was found.

⁷⁹ Upward balancing capacity means that a BSP will reserve a margin to be able to inject balancing energy into the system when activated. Upwards balancing energy is needed when there is less electricity supply than demand (energy deficit). Vice-versa for downward balancing capacity.

- *The time-lag between the balancing capacity auction and the start of the contract period in which the balancing capacity must be offered as balancing energy in the real-time market:* this time-lag can vary from a day to months and may differ by reserve product. The time lag has an effect on how easy it is for market parties to estimate their opportunity cost and how well a TSO can estimate its reserve needs.
- *The (length of) the contract period:* if a BSP's balancing capacity offer is accepted, the BSP is obliged to offer (a certain volume of) balancing energy during a certain period. The contract period can vary from a year to a couple of hours. Variations are also possible such as e.g. a balancing capacity contract that states that the BSP should offer balancing capacity at peak hours for a particular week. The length of the contract period has an influence on the extent to which vRES, storage and DR may be able to participate in the balancing capacity market.

One other important point is whether upward and downward balancing capacity should be procured jointly, in what are called 'symmetric balancing capacity products' (AGORA, 2016). Rodilla and Batlle (2015) argue that by linking the upward and downward reserve requirements vRES and DR are excluded from participation. Hirth and Ziegenhagen (2015) argue that during hours of high renewable production the energy price decreases, which increases the opportunity costs of thermal plants to provide negative balancing power. More precisely, thermal generation offering downward reserves will have to be running at minimal load plus downward reserve power. Therefore, thermal plants will have to bid in the DA or IDM with this quantity. If the marginal costs of the thermal plant are higher than the DA or IDM price it will be making losses because of its commitment to provide downward energy. The lower the prices in the DA or IDM get, the higher its losses, thus the higher its opportunity cost to offer downward balancing. In other words, during the hours vRES is able to supply, thermal generators have high costs. Thus, during such hours it would be efficient to use vRES for downward balancing. Therefore, it is important that Art. 32(3) of the EBGL requires that the procurement of upward and downward balancing capacity for at least FRR and RR shall be carried out separately. However, each TSO may submit a proposal (including an economic justification) to the regulatory authority for a temporary exemption to this rule.

Another non-trivial design parameter is the minimum bid volume. In DAM and IDM this parameter is not considered restricting as it is set low enough (AGORA, 2016). However, in balancing capacity markets, limits are often a lot higher, e.g. for aFRR, the minimum bid size ranges from more than 5 MW in Norway to 1 MW in Belgium. A lower minimum bid size lowers the entry barriers for new players in the balancing market. It should be added that higher minimum volume requirements can be compensated for in the market design if aggregation is allowed. Art. 25(4) of the EBGL provides a list of characteristics for standard products in the balancing capacity (and energy) market.⁸⁰ Examples of characteristics listed other than minimum (and maximum) bid size, are e.g. the ramping period, the full activation time and the minimum and maximum duration of the delivery period. All TSOs have to come up with a proposal for parameter values of these characteristics of standard products (EBGL, Art. 25(2)). Standard product will allow a more fluid integration of balancing markets. The less standard products, the more liquidity. However, a trade-off exists between minimising the number of standard

⁸⁰ Next to fixed standard characteristics, there are also variable characteristics of a standard product to be determined by the BSP during the prequalification or when submitting the standard product bid. One of these variable characteristics is of course the price, others are divisibility, location and the minimum duration between the end of the deactivation period and the following activation. (EBGL, Art. 25(5)).

products to increase liquidity and having enough standard products to satisfy the wide range of technical needs of the different TSOs. This trade-off is one of the reasons that besides standard products, each TSO may develop a proposal defining specific products which could be used in parallel with standard products in their control area. These specific products should be demonstrated to be necessary and non-distortive. Every two years an assessment is made about whether these conditions still hold (EBGL, Art. 26).

Last, but not least, the settlement rule for the balancing capacity auctions provides a point of discussion. Two options are possible: pay-as-bid or marginal pricing (pay-as-cleared). In Box 3 (in Section 4.3.1) the optimal trading setup in the intraday market is discussed: continuous trading (which implies pay-as-bid) or auctions (can be pay-as-bid or marginal pricing). More general arguments also apply for balancing capacity markets. Additionally, Müsgens et al. (2014) argue that specific complexities of balancing markets tend to strengthen the case for uniform pricing. They state that: *'More precisely, bidders on the capacity balancing market will take into account their expected revenues from calls on the energy balancing market. This necessitates accurate estimates of the revenues from the energy market. These are difficult to determine under uniform pricing. However, we will argue that they are even harder to predict with pay-as-bid. Let us consider the situation under uniform pricing first. Under uniform pricing, bidders can simply bid their variable cost on the energy market. However, the expected revenues from the energy market are needed when calculating the optimal capacity bid because bidders have to subtract these revenues from their capacity bid. Hence, suppliers have to estimate market prices on the energy market for different levels of calls and the associated probabilities. It is especially challenging to estimate the probability function empirically. Yet these estimations are even more complex under pay-as-bid. Recall that bidders do not reveal their variable costs on the energy market with pay-as-bid. Instead, to simplify, bidders try to guess the most expensive accepted bid. The determination of the most expensive accepted bid requires an estimation of the probability distribution for calls of different energy levels, however. Bids on the capacity market depend on the expected profit on the energy market, which makes an accurate estimation regarding the energy market even more important. These estimates become harder when strategic bidding is an additional part of the equation.'*

Box 5: The scoring rule for balancing markets

Another discussion related to balancing markets is whether the balancing capacity and energy bids should be cleared separately (as was assumed so far) or jointly. In other words, should the bids with the lowest capacity cost be accepted or the bids with the lowest expected total cost (capacity and expected energy costs)? This is called the scoring rule in Müsgens et al. (2014).

In their paper, Müsgens et al. (2014) state that the expected total cost can be gamed, even in competitive markets. They claim that scoring should be based on capacity bids, as in line with the EBGL. It is stated that: *'[capacity] bids will reflect all relevant costs, including the variable costs of delivering balancing power. To be more precise, rational bidders' capacity bids in competitive markets equal the foregone expected profit on the wholesale electricity market minus the expected profit from called energy – this is the reserve price when offering balancing power.'*

Neuhoff et al. (2016c) oppose and state that due to shorter contracting periods of reserves⁸¹ the interaction between energy and reserve markets increases. As such, efficiency improvements can be made by a joint clearing of balancing energy and capacity.

In the EBGL (Art. 16(6)), it is stated that exceptional the balancing energy price can be predetermined in the balancing capacity contract if proposed by a TSO, however only for specific balancing products and when this approach can be demonstrated to deliver greater economic efficiency. There is a clear trade-off between accommodating specific products with more complex structures and liquidity as markets would be fragmented with fewer BSPs per product category.

No settlement rule is specified for balancing capacity markets in the EBGL. In practice, the settlement rule applied in most EU markets is pay-as-bid over uniform pricing. Also, in some countries prices for balancing capacity of certain reserve products are regulated and not set by an auction, e.g. for aFRR in France (ENTSO-E, 2017h). Regulated prices for FRR and RR are not permitted in the EBGL (EBGL, Art. 32(2)).

6.2.2 Balancing energy market and its key market design parameters

The balancing energy market is cleared (in most cases) very near to or in real-time.⁸² Real-time system imbalances drive the demand for the activation of balancing energy which is selected from a merit order.⁸³ Balancing energy bids for aFRR, mFRR and RR have to be submitted before the balancing energy gate closure time (GCT).⁸⁴ The balancing energy GCT should be harmonised at the Union level.⁸⁵ In terms of timing, the balancing energy GCT should not be before the intraday cross-zonal GCT and as close as possible to real-time (EBGL, Art. 24).

BSPs contracted in the balancing capacity market are obliged to offer balancing energy for their contract duration. It is important to note that the price of the balancing energy bid should not be predetermined in the contract of balancing capacity (EBGL, Art. 16(6)).⁸⁶ Brunekreeft (2015) remarks that if a bid is selected on the balancing capacity market and its bidder is thus obliged to bid in the balancing energy market, this balancing energy market bid can be very high in order to avoid commitment. This way the relevant bidder still earns a balancing capacity payment. Other BSPs without contracted balancing capacity may also bid in the balancing energy market. TSOs also have the

⁸¹ For the good reasons mentioned in Section 6.1.

⁸² In the EBGL in Art. 29(2) it is stated that '*TSOs shall not activate balancing energy bids before the corresponding balancing energy gate closure time, except in the alert state or the emergency state when such activations help alleviate the severity of these system states and except when the bids serve purposes other than balancing pursuant to paragraph 3*'. A methodology for classifying all purposes for the activation of balancing energy has to be developed by all TSOs one year after the entry into force of EBGL (EBGL, Art. 29(3)). In the draft of this methodology it is found that other purposes could be the activation of balancing energy to solve system constraints, such as redispatch actions to deal with load flow or voltage constraints (ENTSO-E, 2016).

⁸³ The real-time system imbalance is determined by the aggregated imbalances of all BRPs (no network congestion assumed). If the system imbalance is negative, meaning a deficit of electricity in the system, upward balancing energy is activated by the TSO to restore the balance. Conversely, if the system imbalance is positive, meaning a surplus of electricity in the system, downward balancing energy is activated by the TSO.

⁸⁴ In most cases the activation of FCR is not remunerated, only its reservation is paid. In case the activation of FCR is not remunerated, FCR is symmetric (offering fast upwards and downward energy) and because of (short and fast) activations in both directions payments would eventually be cancelled out (Van den Bergh et al., 2017).

⁸⁵ It is unclear whether there can be a different harmonised Pan-European balancing energy gate closure per reserve type. This query requires a legal view on EBGL Article 24(1).

⁸⁶ Exceptionally for specific balancing energy products it can be requested that this rule is not applied.

right to compel BSPs to offer their unused generation capacity or other balancing sources as balancing energy when justified (EBGL, Art. 18(7)).

In Figure 26, the Net Regulated Volume (NRV) over 15 minutes as a share of the consumption over the same 15 minutes is shown. The NRV is calculated as the net of the overall activated downward and upward balancing energy volume. The share of balancing energy activated over consumption is declining in both countries.⁸⁷ Lower volumes are observed because of better functioning intraday markets and more efficient TSO cooperation in the activation of balancing energy.

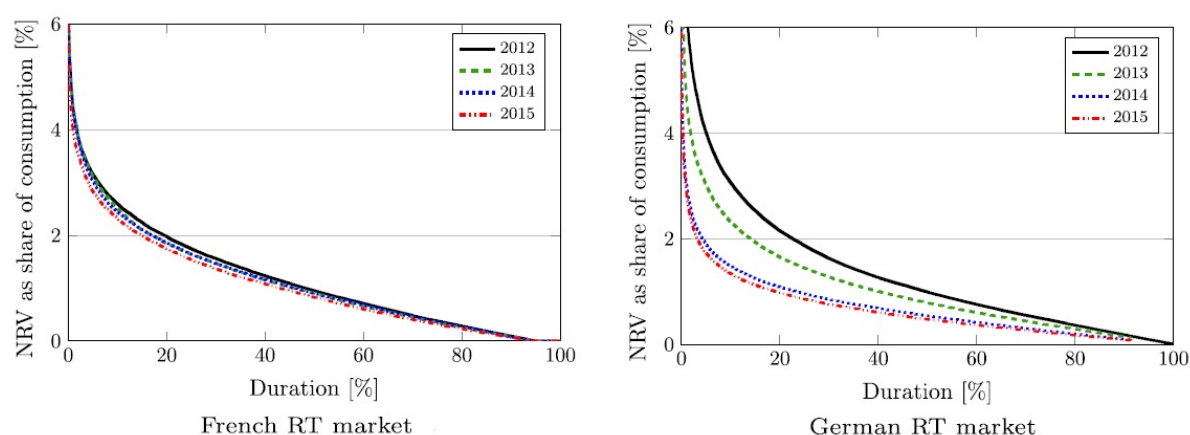


Figure 26: Duration curves of the net regulated volume (NRV) in France and Germany for 2012-2015 (Brijs et al., 2017)

Displaying the NRV per 15 minutes is not a random choice. 15 minutes equals the imbalance settlement period (ISP) in some scheduling areas (e.g. Germany, Belgium, the Netherlands).⁸⁸ Art. 53 of the EBGL outlines that the ISP should be harmonised over scheduling areas. More precisely, it is stated that the ISP should equal 15 minutes in all scheduling areas by three years after the regulation enters into force. An exemption is possible per synchronous area if the TSOs of that synchronous area can justify an alternative duration. Further, for each ISP at least one balancing energy price should be determined for each imbalance settlement period (EBGL, Art. 30(1.c)).⁸⁹

Standard products are also envisioned in the balancing energy market (EBGL, Art. 25(1)). In that regard, the same characteristics as for balancing capacity markets hold for balancing energy markets. Specific balancing energy products per TSO are allowed (EBGL, Art. 26). However, they need to be justifiable and are temporary.

The settlement rule in the balancing energy market is another serious point of controversy. A profound discussion concerning the settlement rule for balancing energy markets was found in Littlechild (2007). Littlechild (2007) favours uniform pricing but is aware that some characteristics of the balancing energy

⁸⁷ The German case is described in more detail in Box 10 of the following chapter.

⁸⁸ For a state of play of the duration of the ISP in the EU in 2014, please consult Exhibit 2 on p. 11 of Frontier Economics (2016).

⁸⁹ 'At least one' could mean that multiple balancing energy prices should exist if both upward and downward energy is activated in the same ISP in one scheduling area (that can happen due to a change of the system imbalance within the duration of one ISP or internal congestion) or could mean different prices for different types of reserves activated in the same direction.

market make it more difficult to apply this rule in some situations. In his paper, he mentioned a paragraph taken from the original proposals for NETA (Review of Electricity Trading Arrangements: Proposals, Offer, July 1998, para 4.49.) wherein an argument in favour of pay-as-bid in the balancing market is given: *'The balancing market will be open for several hours, including real time operation. During this period conditions on the system will be continuously changing. Trades may be accepted at particular times at prices that are quite different from the average price of accepted trades over the period as a whole. Consequently, there is no obvious definition for the marginal or market clearing price throughout the period. To pay a uniform accepted price on all increments of generation and decrements of demand, which would presumably have to be the highest price accepted from any one of them, would not obviously be more efficient and could be expensive.'*⁹⁰ Littlechild (2007) adds that the weight of this argument depends on the gap between the gate closure time and real operation, which has been decreasing since then, and the duration of the settlement period, which has tended to decrease as well.⁹¹

Box 6: The settlement rule in balancing energy markets – specific technical difficulties and implementations in the Netherlands, Belgium and Spain

A problem specific to balancing energy markets arises when different products of different reserve types, for example, aFRR and mFRR, are used at the same instance. In the Netherlands, uniform pricing is applied, and the price is set by the highest bid of the two reserve types, even if this most expensive unit has only been activated for a very short fraction of the ISP (E-Brige Consulting, 2014).

Another practical example illustrating why an adequate settlement rule is difficult to define for the balancing market is the aFRR balancing market in Belgium (as it was in 2014). For technical reasons, the aFRR was activated on a pro-rata basis.⁹² A monthly tender for balancing capacity was organised to contract aFRR capacity. The selection of the balancing energy bids took place D-1 at 18:00, pre-contracted parties were obliged to offer their contracted bids, other parties could place a bid voluntarily. Elia selected up to 150 MW (upwards and downwards) according to their price starting with the lowest one. Then all bids that had been selected day-ahead were activated according to their participation factors for pro-rata activation and paid their bid price (E-Brige Consulting, 2014). Using the marginal pricing rule in this particular case seems counter-intuitive. Today the selection of FRR bids is done using a merit order (Elia, 2017), making it more suitable for marginal pricing.

In Spain, aFRR was also deployed on a pro-rata basis and the pricing issue was solved by valuing the net energy usage (positive or negative) at the marginal price of RR that would have been applied in the settlement period to replace the FRR energy delivered (Rodilla and Batlle, 2015).

⁹⁰ In Littlechild (2015) a similar argument is made, but phrased differently, it is stated that *'in the balancing mechanism near real-time, the system operator does not see a nice stack of energy trades but rather chooses from a plethora of up and down actions each with different dynamic characteristics in the presence of noisy need. Some might be attractive enough to keep for several trading periods. Others will need to be reversed in favour of new opportunities or will come to an end because of self-dispatched movements. In such a context, the concept of marginal cost is a tenuous one. The most expensive 1 MWh bought or sold (even after flagging, tagging and offsetting) is not necessarily representative of the cost of a slight increase or reduction in capacity with respect to the half-hour as a whole.'*

⁹¹ It could be argued that there are almost no significant material changes for the supply-side dispatchable resources, except for contingencies, in e.g. the hour up to real-time. Renewables are obviously different and also the demand side may be a different matter.

⁹² On a discussion between pro rata activation and merit order selection of balancing energy, please consult E-Bridge and IAEW (2016). EBGL prescribes merit order selection of balancing energy bids.

In the EBGL (Art. 30(1.a)) it is clearly stated that the balancing energy market should be based on marginal pricing. However, if all TSOs identify inefficiencies in the application of marginal pricing, they may request an amendment and propose an alternative pricing method if proven more efficient (Art. 30(5)). Art. 30(1.b) adds that the methodology to determine prices for balancing energy shall *‘define how the activation of balancing energy bids activated for purposes other than balancing affects the balancing energy price, while also ensuring that at least balancing energy bids activated for internal congestion management shall not set the marginal price of balancing energy.’* This Article tackles a concern of Littlechild (2007) who states that *‘marginal pricing may lead to erratic prices, especially where the price order ‘stack’ can be distorted or ‘polluted’ by system actions taken by the System Operator.’*

Finally, cap and floor prices for balancing energy are optional. If applied they should be harmonised and take into account the caps and floors applied in the day-ahead and intraday market (EBGL, Art. 30(2)).

6.3 Imbalance settlement mechanism

This Section discusses how the imbalance price or charge, the price an unbalanced BRP needs to pay (or receive), should be set.⁹³ In real-time, the allocated volume (physical real-time energy consumption/generation by a BRP) is not exactly the same as the contractual position for a given imbalance settlement period. Two situations can occur:

- The BRP can have a positive imbalance (long), this implies that:
 - If the BRP is a net buyer, he consumes less electricity than its position.
 - If a BRP is a net seller, he produces more electricity than its position.
- The BRP can have a negative imbalance (short), this implies that:
 - If the BRP is a net buyer, he consumes more electricity than its position.
 - If a BRP is a net seller, he produces less electricity than its position

EBGL (Art. 55) specifies that each TSO shall set up rules to calculate the imbalance price and that an imbalance price shall be calculated for each imbalance settlement period, each imbalance price area and each imbalance direction. The financial flows between TSOs and BRPs are displayed in Table 2. Individual BRPs receive/pay an imbalance settlement depending on the direction of their imbalance. By convention, if the imbalance is positive the BRP will receive the imbalance price multiplied by the volume of its imbalance. If the imbalance is negative, the BRP will pay the imbalance price multiplied by the volume of its imbalance. The imbalance price is a function of the direction and volume of the overall system imbalance and can be positive, negative or zero.⁹⁴

⁹³ Also called ‘cash-out price’ in GB.

⁹⁴ Negative balancing prices are frequently incurred when the system balance is positive and can be explained as follows. The imbalance price is based (in most cases) on the cost of balancing energy needed to restore the system balance, as discussed in more detail later in this section. In the case the system balance is positive, downward balancing energy will need to be activated. In that case BSPs will bid to be selected to reduce their electricity generation (or increase their demand). In the case they reduce their generation they actually ‘win’ the avoided fuel cost. Therefore, they would be willing to pay a price equal or lower than their avoided fuel cost to offer downward balancing energy. As such, the imbalance price becomes negative.

	<i>Imbalance price positive</i>	<i>Imbalance price negative</i>
<i>Positive imbalance BRP</i>	Payment from TSO to BRP	Payment from BRP to TSO
<i>Negative imbalance BRP</i>	Payment from BRP to TSO	Payment from TSO to BRP

Table 2: Financial flows between TSOs and BRPs for imbalances (EBGL, Art. 55(1))

Also, important to add is that the EBGL states in Art. 18(6.c) that:

‘All balance responsible parties shall be financially responsible for their imbalances, and that the imbalances shall be settled with the connecting TSO.’

In the past, it was not unusual that vRES were exempt from being financially responsible for their imbalances as an implicit subsidy for their deployment.

Hirth and Ziegenhagen (2015) remark that TSOs and regulators often view the imbalance settlement primarily from a cost allocation perspective, i.e. as a mechanism to recover balancing cost. However, looking at it from an efficiency perspective, its crucial role is to give an economic incentive to BRPs to avoid (or not avoid) being imbalanced. The imbalance settlement discussion is split up into three parts, each part answering an interrelated question:

1. *Pricing rule*: Should the imbalance settlement be determined by the average balancing energy costs made to solve the imbalances or should it reflect the marginal cost of the system?
2. *Balancing capacity cost allocation*: How should the costs for the reservation of balancing capacity be allocated? Should imbalance settlement prices rise if balancing capacity utilisation reaches a certain level to reflect scarcity?
3. *Single vs dual imbalance pricing*: Should positive and negative schedule deviations be charged the same price? Related to this, can market parties aggregate their imbalances over their portfolio or should they be held accountable at plant/demand facility level?

6.3.1 Pricing rule for imbalance charges

The price signals sent by the imbalance charge should be strong enough to incentivise BRPs to balance their injections and offtakes. As such, the actions of the TSO to solve imbalances in real-time and the volume of reserves that need to be procured are minimised. Chaves-Ávila et al. (2014); Hirth and Ziegenhagen (2015) and Littlechild (2015, 2007) all argue that that efficient resource allocation requires the imbalance price to represent the marginal cost of balancing and that imbalance settlements based on average costs may increase incentives for market parties to intentionally deviate from their schedule.

This discussion of whether the average cost for balancing energy or the marginal balancing energy cost should set the imbalance price cannot be decoupled from the settlement rule for balancing energy. Two cases can be distinguished:

- 1.) *Pay-as-bid for balancing energy*: In this case, BSPs who are activated receive the price of their bid. This means that the average balancing energy cost (average price paid to all BSPs) will be lower than

the cost of the marginal balancing action.⁹⁵ A choice can be made whether the imbalance price should equal the average balancing energy cost or the cost of the marginal action. In the former, a zero-sum situation is created. The latter results in a surplus which can be allocated to the TSO or other parties (e.g. divided among BRPs).

2.) *Marginal pricing of balancing energy*: In this case, BSPs who are activated all receive the price of the marginal bid. This means that the average balancing energy cost (price paid to all BSPs) equals the cost of the marginal balancing action. Therefore, in this case the answer is trivial; it does not matter whether the average or marginal cost of balancing energy sets the imbalance price as they are the same. As mentioned previously, marginal pricing of balancing energy is also put forward in the EBGL.⁹⁶

Box 7: The ‘Price Average Reference Volume (PAR)’ approach in GB (based on ACER and CEER (2016) Littlechild (2015, 2007) and Ofgem (2015))

In GB, a hybrid methodology is in place: the so-called chunky marginal concept is introduced to come to a cost in between the average and marginal cost. The reasoning goes as follows. As balancing energy may be activated for different purposes, and due to the heterogeneity of balancing energy bids activated (for example in terms of duration), it is not easy to determine the real marginal cost of balancing actions. As a result, some sort of ‘representative’ figure for the cost of balancing actions needs to be found.

As a solution, the imbalance price is set equal to the average cost of the most expensive X MWh of balancing purchases during a settlement period, defined as the Price Average Reference Volume (PAR)). As such, a sliding scale is obtained between at one end, applying the average cost, and at the other end, applying the marginal cost of balancing actions to set the imbalance price. The setting of PAR determines whether the imbalance price leans more towards the average or marginal cost.

Historically the PAR was set to 500 MWh. It was proposed to gradually reduce the average cost of the most expensive 500 MWh balancing actions to the most expensive 50MWh (PAR50) in November 2015, before reducing it to 1MWh (PAR1) in the winter of 2018.

Furthermore, in EBGL Art. 55 (4,5) it is specified that:

‘4. The imbalance price for negative imbalance shall not be less than, alternatively:

(a) the weighted average price for positive activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

5. The imbalance price for positive imbalance shall not be greater than, alternatively:

(a) the weighted average price for negative activated balancing energy from frequency restoration reserves and replacement reserves;

⁹⁵ Or equal in an extreme case.

⁹⁶ However, if all TSOs identify inefficiencies in the application of marginal pricing, they may request an amendment and propose an alternative pricing method if proven more efficient (Art. 30(5)).

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.’

6.3.2 Balancing capacity cost allocation

Before starting the discussion about how to allocate the cost of balancing capacity, it is important to have an insight on how significant this cost is relative to the balancing energy cost. In Figure 27 the overall balancing cost and its components over the national electricity consumption for the year 2015 are shown. Additionally, it is also shown what proportion of the balancing costs are covered by imbalance charges.

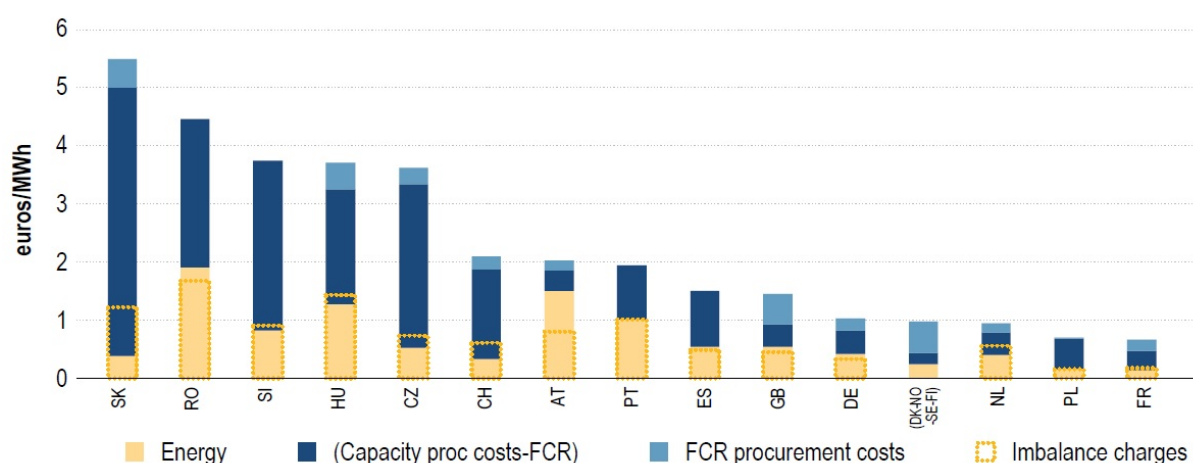


Figure 27: Overall cost of balancing (energy plus capacity) and imbalance charges over the electricity consumption per country in 2015 (ACER and CEER, 2016)⁹⁷

Three observations can be made from Figure 27:

- The total balancing costs over national electricity consumption are very heterogeneous.
- For almost all countries the balancing capacity cost is significantly higher than the balancing energy cost.
- Total imbalance charges are in most countries similar to balancing energy cost, but far from enough to cover the total cost of balancing.

In this section, we focus on observations 2 and 3, more precisely on how to allocate the balancing capacity cost which is shown to be a strong driver of overall balancing costs. ACER and CEER (2016) put forward two important solutions to lower the cost of balancing capacity. Firstly, the integration of balancing markets which would allow for the joint procurement and sharing of reserves.⁹⁸ And secondly, the maximum participation of all technologies in the provision of balancing capacity, including vRES, storage and DR. The EBGL seeks to support the realisation of both complementary solutions to lower the balancing capacity cost.

Traditionally, and still in place in most EU countries today, the balancing capacity procurement costs are socialised. Network users pay these through network charges, or these costs are allocated to BRPs

⁹⁷ 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.

⁹⁸ This is further elaborated upon in Section 7.2.2.

in proportion to their consumed or produced energy volumes (ACER and CEER, 2016). It can be argued that by socialising the cost of reserving balancing capacity the wrong signals are being sent to market parties.

First, by socialising capacity costs, the large generators (or e.g. a large HVDC interconnector) which actually motivate the scale of the reserves might be insufficiently charged for the costs they cause to the system. Neuhoﬀ et al. (2015a) describe this problem as: *‘this [the allocation the cost of balancing capacity procurement to those that cause the need for these reservations] does not imply that the costs of paying for availability of reserves should be allocated to the imbalance of the specific hour, e.g. by spreading the availability costs for the hour across the parties that are in imbalance in this hour. Otherwise, imbalance prices may be very high at times of low imbalance volumes (example Germany). Most availability costs for reserves are thus born by demand and intermittent generation that creates frequent but small-scale deviations rather than large generators that may cause large imbalances that motivated the scale of reserve provision, but are only infrequent in imbalance.’* Also Vandezande et al. (2010) state that the capacity costs for reserves should not be socialised, but borne by those BRPs that cause the need for reservation.

At the same time, BSPs who could provide flexibility at moments of stress (which are exactly the moments wherefore balancing capacity is procured) are not incentivised if prices are not high enough. The same holds for BRPs not being sufficiently incentivised to be balanced at those particular moments.

A solution, called Operating Reserve Demand Curves (ORDC), is brought forward in the literature (see e.g. Hogan (2013) and Papavasiliou and Smeers (2017)) and already implemented in some parts of the US (e.g. in Texas, see e.g. Levin and Botterud (2015)) and in GB (ACER and CEER, 2016). Please note that implementation in GB differs from that in Texas (and details matter), but the philosophy behind the approach is similar. The rationale behind ORDC is to introduce an incentive component when balancing reserves are depleted to a certain level, and the probability of the loss of load becomes non-negligible. This makes sense as by being imbalanced at moments of high system stress, there is not only an energy cost related to solving the imbalance itself but also an increased probability of loss of load. To put a price on this incentive component, the Value of Lost Load (VOLL) and the Loss of Load Probability (LOLP) mapped on the volume of available reserves need to be estimated. Determining a ‘correct’ VOLL is difficult and necessarily implies an administrative intervention, making this procedure more of a challenge to implement.

By applying ORDC, imbalance prices could rise higher than the marginal cost of delivering balancing energy. If only imbalance prices rise and not balancing energy prices (as in the GB implementation), the balancing capacity procurement costs could be (partly) recuperated. With rising imbalance prices BRPs are strongly incentivised to be balanced at moments of system stress. But, a decision could be made to let both the imbalance prices and the balancing energy prices rise at moments of system stress by applying ORDC (as in the US implementation). In this case, not only would BRPs be motivated to be balanced, but BSPs would also have a stronger incentive to be available in real-time at moments they

are needed the most.⁹⁹ In this case, a similar outcome could be achieved by not having balancing energy price caps. However, as stated by Hogan (2013), it would be very difficult if not impossible to distinguish scarcity prices from the exercise of market power. Closing the loop, both implementations, to varying degrees, could lower the need for high volumes of balancing capacity to be procured, leading to lower total balancing capacity costs to be recuperated.

Please note the difference between ORDC and a penalty added to the imbalance price, as also described in Vandezande et al. (2010). First, a penalty is typically applied to the imbalance price in one imbalance direction, not on both imbalance directions. Second, a penalty is in most cases triggered when a certain threshold of balancing energy is activated in real-time. Activation of high volumes of balancing energy does not necessarily imply a situation of system stress as there might be high volumes of reserves available.

Related to the allocation of balancing capacity procurement costs, in Art. 44(3) of the EBGL it is stated that:

‘Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing capacity (pursuant to Chapter 5 of this Title), administrative costs and other costs related to balancing.’¹⁰⁰ The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function. If TSOs choose another mechanism, they should justify this in the proposal. Such a proposal shall be subject to approval by the relevant regulatory authority.’

6.3.3 Single vs dual imbalance pricing

Imagine an imbalance settlement period wherein the system is short of power. In that case, the imbalance price is expected to be positive as it is related to the activated upward balancing power. Now, in that case, should a BRP which has a negative imbalance (short), thus contributing to the system imbalance, be charged an imbalance price equal to that which a positively imbalanced BRP (long), which is thus helping the system, receives?

In the case of single imbalance pricing, this is what happens in practice while with dual imbalance pricing, the short BRP would be charged a different imbalance price to that which the long BRP would receive. In EU countries today both single, dual and hybrid pricing is in place (ENTSO-E, 2017h). Single pricing is often favoured over a dual pricing in the academic literature (Chaves-Ávila and Fernandes, 2015; Hiroux and Saguan, 2010; Littlechild, 2007; Neuhoff et al., 2015a; Newbery, 2006). Under dual pricing, the reverse price (individual imbalances in the opposite direction of the system imbalance) is often linked or capped by a reference or day-ahead market price, while the imbalance in the direction of the system imbalance is linked to the cost of balancing energy.

⁹⁹ Or even stronger, this approach could (partly) solve the missing money problem as giving an additional incentive for flexible generation to be installed.

¹⁰⁰ Chapter 5 of this title (‘Settlement of balancing capacity’) refers to *EBGL Article 56: Procurement within a scheduling area*

1. Each TSO of a scheduling area using balancing capacity bids shall establish rules for the settlement of at least frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

2. Each TSO of a scheduling area using balancing capacity bids shall settle at least all procured frequency restoration reserves and replacement reserves pursuant to the requirements set out in Article 32.

Art. 32(2) of the EBGL is relevant to this matter. It states that single pricing should be applied. However, a TSO may propose to the NRA to apply dual pricing under certain conditions and with the necessary justification. More precisely:

'By one year after entry into force of this Regulation, all TSOs shall develop a proposal to further specify and harmonize at least:

....

(c) the use of single imbalance pricing for all imbalances pursuant to Article 55, which defines a single price for positive imbalances and negative imbalances for each imbalance price area within an imbalance settlement period; and

(d) the definition of conditions and methodology for applying dual imbalance pricing for all imbalances pursuant to Article 55, which defines one price for positive imbalances and one price for negative imbalances for each imbalance price area within an imbalance settlement period, encompassing:

(i) conditions on when a TSO may propose to its relevant regulatory authority in accordance with Article 37 of Directive 2009/72/EC the application of dual pricing and which justification must be provided;

(ii) the methodology for applying dual pricing.'

Many arguments in favour of single pricing are found in the academic literature. An important argument is the fact that dual imbalance pricing discriminates against smaller generation units where companies can aggregate imbalances within a portfolio (Neuhoff et al., 2015a). This is especially the case if there is no liquid intraday market to trade imbalances (Chaves-Ávila et al., 2014). Also, a single imbalance price would constitute a suitable liquid reference price. Further, the dual price imbalance design is reputed to be less cost-reflective than the single price design (Newbery, 2006). Littlechild (2007) explains it as follows: *'[with dual pricing] the reverse price (individual imbalances in the opposite direction of the system imbalance in a dual price system) has been 'deliberately delinked' from the System Operator's costs. It is difficult to see how this is consistent with the stated philosophy of setting imbalance prices to reflect the System Operator's costs. And by linking the imbalance prices with the short-term market prices the risk of distorting the traded market by introducing incentives to influence that market price in order to influence imbalance price is run.'*

Another important argument brought up by Littlechild (2007) in favour of single pricing is that under that mechanism both short and long BRPs participants can contribute to balancing the system, but the dual pricing encourages only one set of market participants to do so.¹⁰¹ This argument relates to Hirth and Ziegenhagen (2015) who see two types of balancing: active and passive balancing. When TSOs deploy balancing energy, they actively balance the system. However, when the imbalance price provides the right incentive to BRPs, these can 'passively' balance the system by purposely deviating from the schedule. This is also called self-balancing. Three preconditions are needed for effective

¹⁰¹ Littlechild (2007) states: *'the significant gap between system buy and sell price seems likely to have distorted decisions on how far each participant decides to balance its own position rather than use the facilities of the System Operator. Not surprisingly, many market participants seem to have taken the view that being short is to be avoided at almost all costs. This is unlikely to be efficient.'*

passive balancing: single pricing, a timely publication of the system imbalance and its price, and the legal ability for BRPs to respond to the price signal (which has not been the case for Germany in the past).¹⁰²

There are also arguments in favour of dual pricing over single pricing. Brijs et al. (2017) and Vandezande (2011) note that speculation of BRPs about the direction of the system imbalance would be avoided with dual pricing. In that same line, if BRPs do not passively balance themselves, it would be easier for the TSO to estimate real-time system imbalances and anticipate power flows. This is of particular importance when internal grid congestion is a frequent issue. An interesting point is made by Chaves-Ávila et al. (2014). In their paper, they mention the fact that a single pricing scheme for a whole country can lead to misleading imbalance prices in the context of internal congestion splitting the scheduling zone into two areas. In that case, market parties can be incentivised to worsen their local imbalance if the imbalance direction is opposite in the different areas. A similar remark is made by Brunekreeft (2015). He states that if the imbalance within one settlement period changes from positive to negative (or the other way around), for one of these imbalances, the imbalance price would be wrong and would set the wrong incentives. In fact, everything would go the other way around, and the system would destabilise. Chaves-Ávila et al. (2014) argue that a nodal or zonal pricing would solve the issue, but that this solution is hard to implement today because of technical and political reasons. A temporary solution would be to use a hybrid pricing rule, more precisely using single pricing when there is a unique direction of regulation and dual pricing when both upward and downward reserves are activated. Chaves-Ávila et al. (2014) conclude that such a scheme can result in a lower efficiency of cost allocation, but that it prevents adverse actions destabilising price signals. This is also the regulation put in place in the Dutch system today (Brunekreeft, 2015).

The last point, directly related to single or dual pricing is whether market parties should be responsible for their imbalances at plant/demand facility level or whether aggregation of their imbalances over their portfolio is allowed, defined as balancing groups by Neuhoff et al. (2016c). Today in Europe this rule is not harmonised (ENTSO-E, 2017h). Balance responsibility on an individual level is compatible with the single pricing, as mentioned before; the financial outcome when imbalances are accounted for individually or on an aggregated scale will not differ. On the contrary, if dual pricing is implemented aggregation will make a difference in the total cost, favouring large portfolios. Additionally, Neuhoff et al. (2016c) argue that balancing groups have a cost for the system as it lowers the liquidity in the balancing market by encouraging balancing within groups and could have the effect that the TSO over-contracts balancing capacity as it does not have a good oversight of balancing resources available in the system. The authors argue that the design of the imbalance price can only partially compensate for this effect and that the problem is aggravated if transmission capacity within a scheduling zone is scarce.

In Art. 54(3) of the EBGL it is left to the individual TSOs to decide whether aggregation of imbalances over a portfolio is allowed. More precisely, it is stated that *'each TSO shall calculate the final position of a balance responsible party using one of the following approaches:*

¹⁰² EBGL (Art. 12(3.a)) states that each TSO shall publish: *'Information on the current system imbalance of its scheduling area, as soon as possible but no later than 30 minutes after real-time.'*

(a) balance responsible party has one single final position equal to the sum of its external commercial trade schedules and internal commercial trade schedules;

(b) balance responsible party has two final positions: the first is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from generation, and the second is equal to the sum of its external commercial trade schedules and internal commercial trade schedules from consumption;'

6.4 The activation of balancing energy: two approaches

Two approaches to the activation of balancing energy are identified in the EU, reactive balancing and proactive balancing (Elia and TenneT, 2014; Haberg and Doorman, 2016; Pentilateral Energy Forum, 2016). The key difference between the two approaches is that with reactive balancing the TSO activates balancing energy to counteract imbalances in real-time, while with proactive balancing the TSO activates balancing energy before real-time based on forecasts of imbalances.¹⁰³ The activation strategy of balancing energy cannot be decoupled from the reliance of a TSO on BRPs to self-balance and thus the imbalance settlement mechanism. With a reactive approach, the TSO relies more heavily on the engagement of decentralised (proactive) market players in managing the system imbalance. Therefore, shorter imbalance settlement periods and single imbalance pricing fit well with this approach.

Conversely, the proactive approach relies more strongly on active balancing by the TSO and generally gives weaker incentives to the BRPs. The flexibility of the available generation mix, which is in its turn in most cases a function of the size of the system and its interconnectivity, has an influence on the applied activation strategy. A proactive approach is often believed to increase system security in the case of more isolated systems (with little flexible capacity) possibly combined with a high share of vRES generation resulting in unpredictable electricity flows. An overview of a selection of EU countries and their approach to the activation of balancing energy is shown in Figure 28. Additionally, in the same Figure, the relationship between BRP incentives and the activation strategy is displayed. It can be seen that there are also countries (e.g. Denmark) applying an approach in between reactive and proactive balancing.

¹⁰³ At least one hour before real-time is mentioned by Pentilateral Energy Forum (2016).

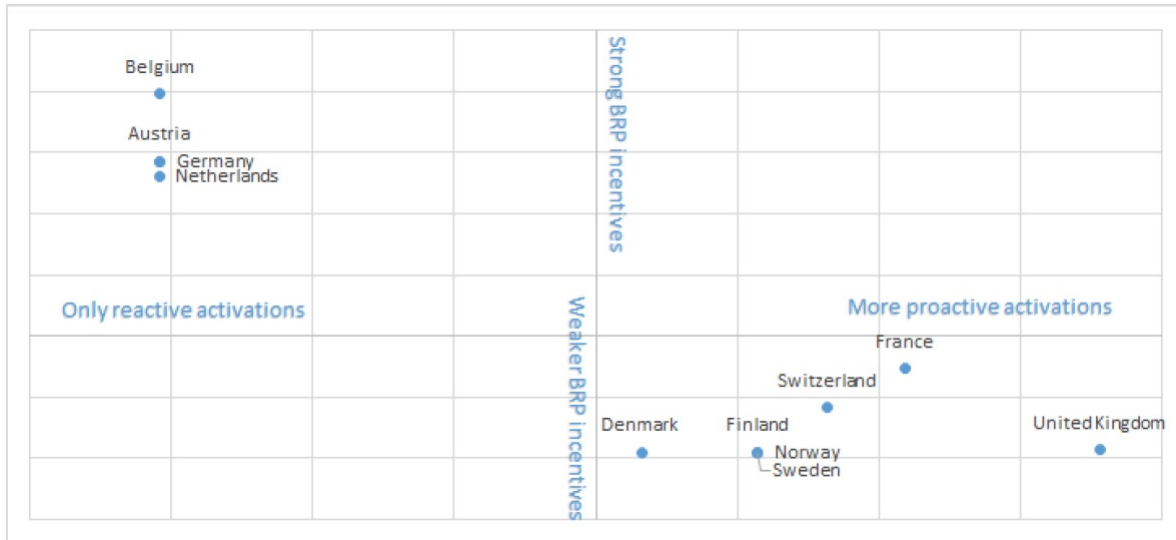


Figure 28: Classification of European balancing markets based on activation strategy in balancing energy and BRP incentives (Haberg and Doorman, 2016). Additionally, Portugal and Spain are identified as proactive by the Pentilateral Energy Forum (2016).

In a document by the Pentilateral Energy Forum (2016) the rationale behind both approaches is summarised as: *'The objective of the proactive approach is to minimize the overall balancing costs by reducing the average balancing energy price, whereas in the reactive approach, the objective is to minimize the overall balancing cost by reducing the volume of balancing energy.'* Another distinction is that TSOs applying the reactive approach generally do not procure RR, while TSOs applying a proactive approach do and can activate manual reserves (mFRR or RR) to intervene before real-time (Elia and TenneT, 2014).

It is important to add that the reactive approach relies on a liquid and well-functioning intraday market and intraday gate closure near real-time, making it possible for BRPs to trade their imbalances. As such, the need for the activation of large volumes of balancing energy in real-time is minimised. In contrast, it can be argued that a proactive approach distorts the functioning of the intraday market. Two issues can be identified. First, the resources that are procured for proactive balancing (RR) are not available anymore to trade in the intraday market, lowering supply in that market. Second, by minimising the real-time imbalance and as a consequence also the balancing prices and imbalance charges, BRPs have less incentive to trade in the intraday market to be balanced, thus reducing demand in that market. Actually, by applying proactive balance BRPs do not receive price signals indicating system stress. Instead, price signals are dampened by intervention before real-time. The cost of this real-time intervention then needs to be recuperated in other, less cost reflective ways.

The EBGL and SOGL do not explicitly favour one approach to the activation of balancing energy over the other. It seems that within these regulations both approaches are allowed, although 'very' proactive balancing seems to be restricted. There are several articles of importance with respect to this matter. Most importantly, in Art. 29(2,3) of the EBGL it is stated that:

'2. TSOs shall not activate balancing energy bids before the corresponding balancing energy gate closure time, except in the alert state or the emergency state when such activations help alleviate the severity of these system states and except when the bids serve purposes other than balancing pursuant to paragraph 3.'

3. By one year after the entry into force of this Regulation, all TSOs shall develop a proposal for a methodology for classifying the activation purposes of balancing energy bids. This methodology shall:

- (a) describe all possible purposes for the activation of balancing energy bids;
- (b) define classification criteria for each possible activation purpose.'

Looking back at Art. 24(1,2) of the EBGL, regarding the balancing energy GCT, it is stated that:

'1. As part of the proposals pursuant to Articles 19, 20 and 21, all TSOs shall harmonise the balancing energy gate closure time for standard products at the Union level, at least for each of the following processes:

- (a) replacement reserves;*
- (b) frequency restoration reserves with manual activation;*
- (c) frequency restoration reserves with automatic activation.*

2. Balancing energy gate closure times shall:

- (a) be as close as possible to real time;*
- (b) not be before the intraday cross-zonal gate closure time;*
- (c) ensure sufficient time for the necessary balancing processes.'*

Furthermore, in the CACM (Art. 59(3)), concerning the intraday cross-zonal GCT, it is stated:

'One intraday cross-zonal gate closure time shall be established for each market time unit for a given bidding zone border. It shall be at most one hour before the start of the relevant market time unit and shall take into account the relevant balancing processes in relation to operational security.'

These articles imply that the balancing GCT will be at most one hour before real-time and would mean that proactively activating balancing energy long (a couple of hours) before real-time will not be allowed unless in an alert on emergency state. However, on the other hand, procurement of RR and having in place a Reserve Replacement Process (RRP), compatible with the proactive balancing approach, is a right described in EBGL (Art. 19) and SOGL (Art. 140(2)). In Art. 144(1) of SOGL it is stated that:

'The control target of the RRP shall be to fulfil at least one of the following goals by activation of RR:

- (a) progressively restore the activated FRR;*
- (b) support FRR activation;*
- (c) for the GB and IE/Nl synchronous areas, to progressively restore the activated FCR and FRR.'*

Box 8: Self-dispatch vs central dispatch models

Several articles in the EBGL and the SOGL mention that (slightly) different provisions hold for self-dispatch or central dispatch systems, the two dispatch models applied in the EU. Self-dispatch models can be reactive or proactive in their activation of balancing energy. If a similar label should be put on central dispatch models, they can be categorised as extremely proactive in their balancing approach.

The self-dispatch model is the most common and defined *'as a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those*

facilities' (EBGL, Art. 2(17)). On the contrary, with a central dispatch model *'the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a TSO within the integrated scheduling process'* (EBGL, Art. 2(17)). An integrated scheduling process means that balancing, reserve procurement and congestion management are done concurrently (Marneris and Biskas, 2015).

In short, under the self-dispatch model different markets are organised for different purposes (balancing energy, balancing capacity and congestion management) and market parties with their economic incentives are more important, while under central dispatch an integrated process is executed with a much greater role for the TSO. Currently, the central dispatch model is in place in e.g. Greece, Hungary, Italy and Poland (Marneris and Biskas, 2015). Ireland is in a transition from a central dispatch to a self-dispatch model.

The self-dispatch model is more in line with the European Target model (see also ACER (2015b) and Gorecki (2013)) and is seen as 'default' in the EBGL as can be deduced from Art. 14(2):

'Each TSO shall apply a self-dispatching model for determining generation schedules and consumption schedules. TSOs that apply a central dispatching model at the time of the entry into force of this Regulation shall notify to the relevant regulatory authority in accordance with Article 37 of Directive 2009/72/EC in order to continue to apply a central dispatching model for determining generation schedules and consumption schedules. The relevant regulatory authority shall verify whether the tasks and responsibilities of the TSO are consistent with the definition in Article 2(18).'

Therefore, the working of the balancing mechanism described in this Chapter and the next Chapter refers to the self-dispatch model. Otherwise, it is explicitly stated.

7. Integrating balancing markets

Great efficiency gains and an increase in security of supply can be achieved by integrating balancing markets. For example, see the report by Mott MacDonald (2013) in which it is estimated that the theoretical benefit of the full integration of balancing markets with hypothetical scenarios of the European system in 2030 is up to 3 billion € per year, or the study by Artelys et al. (2016) in which it is shown that most monetary gains can be made by joint dimensioning and procurement of reserves (open for DR and RES) at EU level. However, balancing mechanisms are complex and different national approaches have grown organically to best fit local needs. As a result, it is not straightforward to integrate this segment of the electricity market sequence. An important difference between the integration of DA and ID markets and balancing market is highlighted by Neuhoff and Richstein (2016b). They state that for DA and ID markets the focus was mainly on a harmonisation of products, timelines and transmission capacity allocation, while with balancing one important challenge is added, namely the harmonisation of operational paradigms. In other words, in itself the alignment of markets is not enough – certain relevant elements of system operation must also be aligned.

The two important network codes in this regard are the EBGL and SOGL. The EBGL described the principles, market rules and proposals which need to be followed, implemented or developed to allow balancing markets to integrate. In parallel to the development of these rather ‘top-down’ regulations, different balancing pilots have been launched since 2013. Balancing pilots are voluntary initiatives which aim to gain bottom-up experience for the implementation of different aspects of the integration of European balancing markets. In Figure 29 an overview of the different balancing pilots in Europe is given. Balancing pilots are dynamic projects and their active members can evolve as can be seen from the Figure.

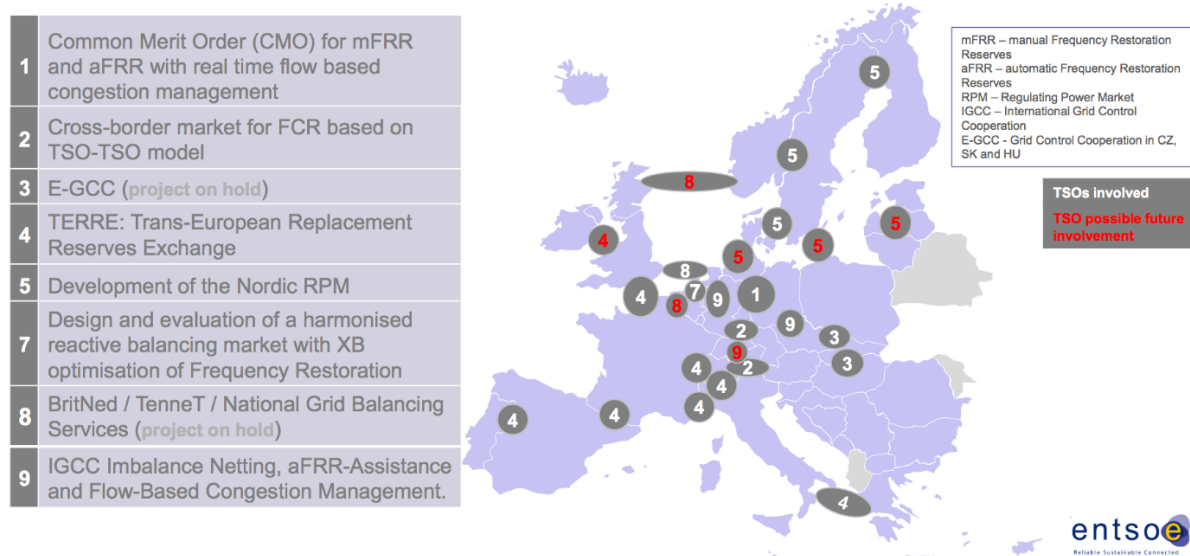


Figure 29: Overview of the balancing pilot projects (ENTSO-E, 2017i)

This chapter is split into two sections. First, a discussion is held on what market design blocks or operational paradigms need to be harmonised to allow the efficient integration of balancing markets. There seems to be no consensus for the moment. Second, four complementary ways of cross-zonal cooperation in balancing are described: imbalance netting, the exchange of balancing energy, the exchange of balancing capacity and sharing of reserves. That section also deals with cross-zonal transmission capacity allocation for balancing purposes.

7.1 How far should harmonisation go to allow for integration?

In earlier drafts of the EBGL, e.g. the version 3.0 published on the 30th of August 2014, a concept called Coordinated Balancing Areas (CoBAs) was mentioned.¹⁰⁴ In that version of the EBGL, CoBAs are defined as *‘a cooperation with respect to the Exchange of Balancing Services, Sharing of Reserves or operating the Imbalance Netting Process between two or more TSOs.’* The main idea behind CoBAs was a phased approach toward the full integration of balancing markets. First, regional initiatives (as with the balancing pilots), allowing for more flexibility in design, would emerge which would then slowly be merged. ACER (2015c) also confirmed that a regional implementation is an unavoidable interim step to single EU-wide integration. However, CoBAs were removed in the final version of the EBGL (approved by the MSs on 16 March 2017), and the focus was laid more strongly on the (single) European Target Model. However, the line of thought behind CoBAs has not been fully discarded, and regional initiatives are still deemed the way forward as stated by TenneT et al. (2016).

Box 9: Two regional balancing initiatives – TERRE and EXPLORE

Two regional balancing initiatives often referred to are TERRE and EXPLORE. TERRE moved from being a pilot to an implementation project for the European platform for the exchange of replacement reserves (EBGL, Art. 19). EXPLORE is not an official balancing pilot but a joint initiative of four TSOs interested in more balancing cooperation. In July 2017, the PICASSO project (Platform for the International Coordination of the Automatic frequency restoration process and Stable System Operation) was initiated.¹⁰⁵ The PICASSO project builds further on the work done in EXPLORE and is the implementation project for the European platform for the exchange of aFRR (EBGL, Art. 21).

TERRE stands for ‘Trans European Replacement Reserves Exchange’ and has 8 active partners: two TSOs in Great Britain, the TSOs from France, Spain, Portugal, Italy, Switzerland and Greece. The TSOs from Ireland and Northern Ireland are observers. ENTSO-E (2017j) described the objective of TERRE as: *‘setting up and operating a multi-TSO platform capable of gathering all the offers for Replacement Reserves (RR) and to optimise the allocation of RR across the systems of the different TSOs involved. It is moving towards cross-national exchange of RR.’* It is no coincidence that all TSOs involved in the project apply a rather proactive approach to the activation of balancing energy. Neuhoﬀ and Richstein (2016b) add that the TERRE countries provide room for the continuation of national procedures as the operational paradigms between these countries, although all rather proactive, still significantly differs.

EXPLORE stands for ‘European X-border Project for Long-term Real-time balancing Electricity market design’ and is an initiative of the TSOs of four countries: Austria, Belgium, Germany and the Netherlands. The objective of the EXPLORE study is to investigate how to exchange most optimally Frequency Restoration Reserves (FRR) while taking into account interactions with other balancing processes and the spot market. All countries participating in this project apply a reactive approach to the activation of balancing energy and, in contrast to the TERRE countries, show more commonalities in their approach to the balancing mechanism as also confirmed by Neuhoﬀ and Richstein (2016).

¹⁰⁴ Link:

[https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20EB/140806_NCEB_Resubmission to ACER v.03.PDF](https://www.entsoe.eu/Documents/Network%20codes%20documents/NC%20EB/140806_NCEB_Resubmission_to_ACER_v.03.PDF) consulted on 21/12/2017.

¹⁰⁵ The website of the Picasso project: https://electricity.network-codes.eu/network_codes/eb/picasso/ consulted on 21/12/2017.

In a document by the Pentilateral Energy Forum (2016), it is remarked that ACER and ENTSO-E hold different views on the degree of harmonisation needed across regional initiatives. ACER reasons that a sufficient degree of harmonisation is needed in order to avoid getting stuck with incompatible regions, while it is stated in that document that ENTSO-E is of the opinion that regional balancing initiatives can start without complete harmonisation. It can be said that the final version of the EBGL leans more towards ACER's view.

Standardised balancing products and a harmonised balancing energy gate closure time (GCT) are the two dimensions whose harmonisation both parties agree is absolutely necessary for integration. The EBGL outlines that standard balancing products need to be defined in Art. 25. However, as also described in the previous Chapter, if requested by a TSO and justified, temporarily specific balancing products might be in place in parallel with standard products (Art. 26(1)). The EBGL also states that these standardised balancing energy products for mFRR, aFRR and RR need to be exchanged on European trading platforms (EBGL, Art. 19, 20 and 21). Regarding the balancing energy GCT, Art. 24(1) of the EBGL firmly states the GCT for standardised products should be harmonised for at least mFRR, aFRR and RR processes.

Two no-regret options needed for the integration of balancing markets as stated by Neuhoﬀ and Richstein (2016), and also agreed upon by ACER (2015c), are the harmonisation of the imbalance settlement period (ISP) and the agreement on the pricing rule in balancing energy markets. Regarding the former and as already mentioned in the previous chapter, the EBGL states clearly that the ISP should be 15 minutes in all control areas (EBGL, Art.53(1)).¹⁰⁶ Art. 53(2, 3) of the EBGL states that an exemption can be requested by all TSOs of a synchronous area. In that case the relevant NRAs have to approve. Or, the relevant NRAs of the synchronous area can decide to exempt themselves. In both cases the relevant NRAs have to conduct a CBA (at least every 3 years) in cooperation with ACER to show whether it is reasonable not to harmonise the ISP with other synchronous areas and/or within their own synchronous area.

Also, the pricing rule in balancing energy markets was already discussed in the previous chapter and is determined in the EBGL. In Art. 30(1.a) of the EBGL it is stated that marginal pricing should be applied. TSOs might propose an amendment or alternative to this rule if they can identify inefficiencies in the application of this methodology (EBGL, Art. 30(5)).

In addition to the four mentioned dimensions of balancing markets, ACER (2015c) argues that there is a need to go further to avoid divergent regional designs. Additional dimensions identified are principles for (activation) algorithms and TSO-TSO settlement rules.¹⁰⁷ In the document by the Pentilateral Energy Forum (2016) the need to harmonise the activation purposes of balancing energy is added to the view of ACER.

7.2 Inter-TSO cooperation in balancing

Four complementary forms of coordinated balancing are identified in the EBGL and SOGL. In the following, they are described in pairs. First, imbalance netting and the exchange of balancing energy

¹⁰⁶ It is no secret that not all MSs agree with this view. Also, a CBA performed for ENTSO-E by Frontier Economics (2016) is not in favour of such full harmonisation.

¹⁰⁷ TSO-TSO settlement rules are discussed in the next section of the chapter.

are bundled as they more directly affect the balancing energy market. Then, the exchange of balancing capacity and sharing of reserves are jointly discussed. These forms of coordinated balancing have a more direct impact on the balancing capacity market. The exchange of balancing capacity and sharing of reserves adds a layer of difficulty as cross-zonal transmission capacity must be reserved or anticipated to serve these purposes. In contrast, for imbalance netting and the exchange of balancing energy, cross-zonal capacity must be available as these processes take place in real-time.

Box 10: ‘The German Paradox’ – more renewables but less and cheaper reserves?

Generally, with an increased share of vRES in the system the reserve requirements would intuitively be expected to increase as well. But this is not necessarily the case. While in Germany the vRES capacity has tripled since 2008, reserve requirements had been reduced by 15%, and costs by 50% by 2014. (Hirth and Ziegenhagen, 2015). This indicates that other factors can be quantitatively more important than vRES in determining the reserve requirement.

Ocker and Ehrhart (2017) investigate this paradox in their paper and attribute the reduction in reserve requirement, next to better forecasting techniques of vRES generation, to two factors:

International and national cooperation: from 2009 to 2010 the four German TSOs introduced a common balancing market.¹⁰⁸ As a result, counteracting activations of balancing energy in different balancing areas could be avoided and fewer reserves needed to be procured, leading to significant savings (see also Haucap et al. (2014)). Additionally, the International Grid Control Cooperation (IGCC) was founded, and as a consequence significant amounts of balancing energy was saved.¹⁰⁹

Adaptations to the German energy market design: a strong increase in intraday trading was witnessed from 2006-2014. Intraday trade leads to a reduced need for balancing. Additionally, it is argued that the introduction of the intraday action with 15-minute products in December 2014 helped to allow more precise scheduling of vRES and other generation technologies.

7.2.1 Lower volumes of cheaper balancing energy: imbalance netting and the exchange of balancing energy

Imbalance netting is defined in Article 3(128) of the SOGL as ‘a process agreed between TSOs that allows avoiding the simultaneous activation of FRR in opposite directions, taking into account the respective FRCEs as well as the activated FRR and by correcting the input of the involved FRPs accordingly.’ Put simply, if for example, two neighbouring LFC Areas have an opposite system imbalance at a point in time, the TSOs can agree to exchange the imbalance, and thus avoid the activation of counteracting balancing energy (FRR in this case) in both LFC Areas. This process leads to an overall reduction in the total volume of activated balancing energy and thus a cost reduction.¹¹⁰ ACER and CEER (2016) report that imbalance netting continued to be the most successfully applied tool to exchange balancing services in 2015, e.g. in the Netherlands imbalance netting avoided almost 50% of the balancing needs for that year.

¹⁰⁸ The project, called the German Grid Control Cooperation (GCC), consists of 4 modules: 1) Prevent counteracting reserve activation; 2) Common dimensioning of reserves; 3) Common procurement of FRR; 4) Cost-optimised activation of reserves. For more information, please consult Regelleistung.net (2017).

¹⁰⁹ The IGCC is further developed in the next Section.

¹¹⁰ There could be (rare) situations where the savings triggered by the activation of downward reserves (fuel cost savings) are larger than the cost of activating upwards reserves.

Art. 22(1) of the EBGL outlines that a proposal for the implementation framework for a European Platform for imbalance netting shall be developed. In Art. 22(5) it is further stated that: *'by one year after the approval of the proposal for the implementation framework for a European platform for the imbalance netting process, all TSOs performing the automatic frequency restoration process pursuant to Part IV of Commission Regulation (EU) 2017/000 [SO] shall implement and make operational the European platform for the imbalance netting process. They shall use the European platform to perform the imbalance netting process, at least for the Continental Europe synchronous area.'* ENTSO-E (2017k) describes that TSOs have gained experience with imbalance netting through pilot projects including 'International Grid Control Cooperation' (IGCC), 'e-GCC' and the 'Imbalance Netting Cooperation' (INC). It was later agreed the IGCC would be used as the starting point for the implementation of the European process.¹¹¹ It is important to add that the EBGL also outlined that common settlement rules for imbalance netting shall be developed by all TSOs in Art. 50(1.d). For IGCC the volumes of exchange energy of each IGCC member are settled by calculating the opportunity costs, reflecting the value of netted imbalances (see IGCC Settlement Principles (ENTSO-E, 2017k)) for the rules and Verpoorten et al. (2016) for a case study).

A second way to lower overall balancing cost is by the exchange of balancing energy across scheduling areas. The exchange of balancing energy is defined in Article 2(24) of the EBGL as *'the activation of balancing energy bids for the delivery of balancing energy to a TSO in a different scheduling area than the one in which the activated balancing service provider is connected.'* Two models are possible when exchanging balancing energy: TSO-TSO or the TSO-BSP model. In the TSO-TSO model, the balancing service provider provides balancing services to the TSO it is connected with, which then provides these balancing services to the TSO requesting the balancing energy. In the TSO-BSP model, the BSP provides balancing services directly to the contracting TSO, which then provides these balancing services to the requesting TSO. The contracting TSO is defined as *'the TSO that has contractual arrangements for balancing services with a BSP in another scheduling area'* (EBGL, Art. 2(44)).

The EBGL clearly states that the TSO-TSO model should be preferred. More precisely, Art. 19(2), 20(2) and 21(2) state that a European platform for RR, mFRR and aFRR needs to be developed which shall apply a multi-lateral TSO-TSO model with common merit order lists to exchange all balancing energy bids from all standard products. Exceptions from the TSO-TSO model are possible. Namely, two or more TSOs may on their initiative or at the request of their relevant regulatory authorities develop a proposal for the temporary application of the TSO-BSP model (EBGL, Art. 35 (1)). Also, current practices applying a TSO-BSP model are allowed in cases where the connecting TSO has not implemented a certain product process, for instance, the Reserve Replacement Process, to allow cross-zonal exchange of this product (EBGL Art. 35 (6)). The TSO-TSO model with common merit order list can lead to savings in the procurement of balancing energy as resources can be more efficiently allocated. Figure 30 illustrates the workings of a common merit order list.

¹¹¹ IGCC finds its origin in the cooperation of balancing services by the four German TSOs. Currently IGCC involves 11 TSOs from 8 countries. These are the TSOs from Austria, Belgium, Switzerland, Czech Republic, Germany, Denmark, France and the Netherlands (ENTSO-E, 2017k).

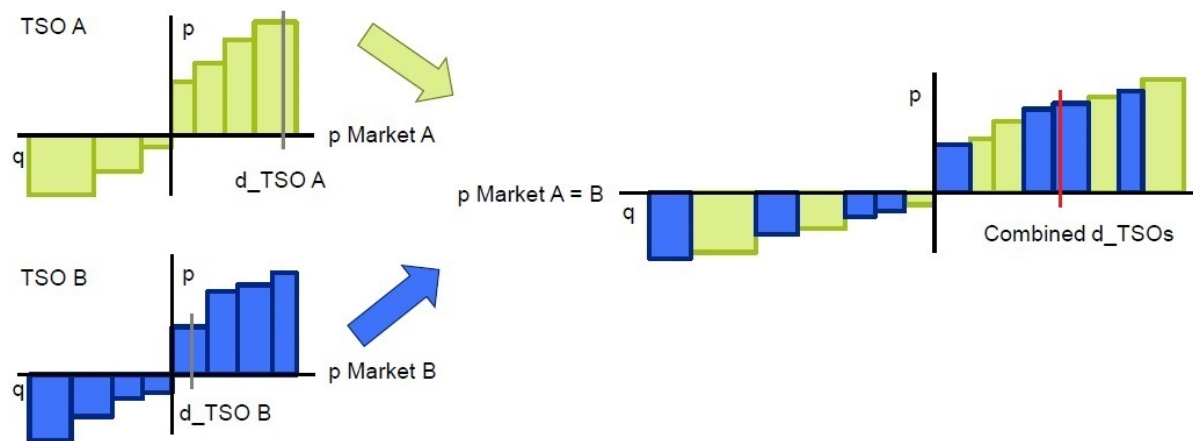


Figure 30: Illustration of the efficiency gains with a common merit order list for the activation of balancing energy under no congestion. ‘p’: price, ‘q’: quantity and ‘d’: demand (Elia et al., 2013).

Also, the EBGL outlines in Art. 50(1.a-c) that common settlement rules shall be developed by all TSOs in the case of the exchange of balancing energy. Two remarks about the exchange of balancing energy need to be added. First, the total balancing volume a TSO may request for activation from the common merit order list is limited by its own contribution of balancing energy bids to the list (for more details, see EBGL Art. 29(12)). Exceptions to this rule can be proposed by TSOs, provided that all other TSOs are informed (EBGL, Art. 29(13)). Second, a TSO can declare a balancing energy bid submitted to the activation function of the common merit order list unavailable for the activation by other TSOs only in case of internal congestion or due to operational constraints within the connecting TSO’s scheduling area (EBGL, Art. 29(14)).

In order to conduct imbalance netting or the exchange of balancing energy, available transmission capacity between scheduling areas or LFC Areas is a prerequisite.¹¹² In relation to this, Art. 36(1) requires that all TSOs shall use the available cross-zonal capacity after the cross-zonal intraday gate closure for the exchange of balancing energy or for operating the imbalance netting process. Two situations can exist, assuming there is spare capacity in both directions between two LFC Areas:

- *The imbalances in both areas are opposing:* First, imbalance netting will take place. Then, if the imbalance in one of the areas persists and the transmission line is not congested, the exchange of balancing energy can take place.
- *The imbalances in both areas are in the same direction:* No imbalance netting will take place. The exchange of balancing energy can take place.

A methodology per Capacity Calculation Region (CCR) will be developed to calculate the available cross-zonal capacity within the balancing time frame (EBGL, Art 37(3)). It is not mentioned in the EBGL

¹¹² An exemption to this statement holds for the exchange and operation of FCR (EBGL, Art. 38(4)). FCR can be exchanged using the reliability margin, calculated as described by CACM, Art. 22. This exemption does not hold if the interconnector is a DC line.

whether cross-zonal capacity can be reserved specifically for imbalance netting or the exchange of balancing energy.¹¹³

7.2.2 More efficient reserve procurement and sizing: exchange of reserves and reserves sharing

Next to imbalance netting and the exchange of balancing energy, the exchange of reserves and reserve sharing are also outlined in the EBGL as important to lower overall balancing procurement costs.

The exchange of balancing capacity is defined in Art. 2(25) of the EBGL as *'the provision of balancing capacity to a TSO in a different scheduling area than the one in which the procured BSP is connected.'* An example is a project for cross-zonal exchange of FCR capacity which started in late 2015 and involved the German, Austrian, Dutch and Swiss TSOs. ACER and CEER (2016) report that the exchange of balancing capacity allowed a reduction of approximately 14% in the overall balancing capacity procurement costs for FCR in 2015 when comparing with 2014 for these four countries recorded.

The same two models for the exchange of balancing capacity are possible as with the exchange of balancing energy: TSO-TSO and the TSO-BSP model. Also, in this case, the EBGL states that the exchange shall always be performed based on a TSO-TSO model unless the same exceptions as with the exchange of balancing energy hold (EBGL, Art. 33(2)). As all TSOs engaged in exchanging balancing capacity submit all balancing capacity bids from standard products to a common capacity procurement optimisation function (EBGL, Art. 33(3)), a more efficient allocation of resources will result. Overall balancing capacity reservation costs can be lowered, and BSPs can benefit from access to an enlarged market without new pre-qualification procedures or contracts.

However, as remarked by Doorman and Van Der Veen (2013), it might be more difficult to convince TSOs to exchange balancing capacity than to exchange balancing energy. Namely, a TSO with low-cost balancing resources may see an increase in its balancing procurement cost when sharing these resources with areas with higher cost resources. In the case of balancing energy, potential cost increase for a TSO will be passed on to BRPs causing the imbalances. In most cases, this will be a zero sum for the TSO as discussed before. However, in the case of reserve capacity, these costs are often included in the grid tariffs, and increasing them might prove to be more difficult. This reasoning could serve as an additional argument to include balancing capacity cost in imbalance prices.

It can be said that sharing of reserves goes one step further than the exchange of balancing capacity. Namely, with reserve sharing more than one TSO takes the same reserve capacity (FCR, FRR or RR) into account to fulfil its respective reserve requirements (SOGL, Article 3(97)).¹¹⁴ Sharing of reserves can lead to lower overall volumes of balancing capacity, which is not the case with the exchange of balancing capacity in the strict sense. However, to make sharing of reserves feasible, difficult estimates need to be made about the probability that TSOs would need the same balancing resource at the same moment. A very important example of sharing of reserves, which is already in place, is the joint dimensioning of FCR. As also discussed by Van den Bergh et al. (2017), FCR is dimensioned to cover the

¹¹³ However, as discussed in the next subsection, cross-zonal transmission capacity can be reserved for the exchange of balancing capacity or for the sharing of reserves. And thus, indirectly also for balancing energy exchange.

¹¹⁴ By definition this balancing capacity is cross-zonal for all TSOs involved except for the connecting TSO.

worst-case event (e.g. tripping of the largest generator unit). However, the probability that a worst-case event happens in several EU countries is very low. Therefore, FCR is dimensioned at the scale of the synchronous area with a key determining how much each control area should contribute. This arrangement obviously leads to significant savings for all countries.

Unlike imbalance netting and the exchange of balancing energy, the exchange of balancing capacity and sharing of reserves are voluntary initiatives between two or more TSOs (EBGL, Art. 33(1) and 38(1)). However, a balancing report shall be published at least every two years by each TSO wherein the opportunities for the exchange of balancing capacity and sharing of reserves should be analysed. Additionally, an explanation and justification for the procurement of balancing capacity without the exchange of balancing capacity or sharing of reserves should be given (EBGL, Art.60(2.e- f)).

In order to exchange balancing capacity or share reserves, the availability of transmission capacity in real-time between scheduling areas needs to be anticipated. Article 36(2.c) and more precisely Article 38(5) of the EBGL describe that cross-zonal capacity for the exchange of balancing capacity or sharing of reserves can be allocated. Cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves shall be used exclusively for FRR and for RR (EBGL, Article 38(4)). The reserved capacity shall be limited depending on the way the reserved capacity is calculated (Article 40 (1.d), 41(2) and 42(2)). It should be added that all TSOs exchanging balancing capacity or sharing of reserves shall regularly assess whether the cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is still needed for that purpose as it means that this capacity is no longer offered to wholesale markets (Article 38(8)).

Capacity allocation for the exchange of balancing capacity or sharing of reserves is a stochastic problem as described by Van den Bergh et al. (2017). What is meant by this is at the time the transmission capacity is allocated, the state of the system and thus the need for the activation of balancing energy in a certain direction is uncertain, as is the remaining interconnection capacity. This renders it difficult to estimate the optimal volume and direction of the transmission capacity to be reserved. In the EBGL three methods to obtain estimates for the optimal cross-zonal capacity for the purpose of the exchange of balancing capacity or sharing of reserves are enumerated: an approach based on economic efficiency analysis, a market-based approach and a co-optimisation approach.

The three approaches can be described as follows:

- *Approach based on economic efficiency analysis:* a method based on a comparison of the forecasted market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, and the forecasted market value of cross-zonal capacity for the exchange of energy (EBGL, Art. 42 (3)).¹¹⁵ Cross-zonal capacity is reserved before the transmission capacity auction for the exchange of energy takes place. This method, if in place, applies for the exchange of balancing capacity or sharing of reserves with a contracting period of more than one day and where the contracting is done more than one week in advance of the provision of the balancing capacity (EBGL, Art. 42(1)).

¹¹⁵ 'The forecasted market value of cross-zonal capacity for the exchange of energy between bidding zones shall be calculated based on the expected differences in market prices of the day-ahead and, where relevant and possible, intraday markets between bidding zones.' (EBGL, Art. 39(5))

- *Market-based approach*: a method based on a comparison of the actual market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves and the forecasted market value of cross-zonal capacity for the exchange of energy, or on a comparison of the forecasted market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves, and the actual market value of cross-zonal capacity for the exchange of energy (EBGL, Art. 41(3)).¹¹⁶ Cross-zonal capacity can be reserved just before or just after allocation for the exchange of energy. This method, if in place, applies for the exchange of balancing capacity or sharing of reserves with a contracting period of not more than one day and where the contracting is done not more than one day in advance of the provision of the balancing capacity (EBGL, Art. 41(1)).
- *Co-optimisation approach*: a method based on a comparison of the actual market value of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves and the actual market value of cross-zonal capacity for the exchange of energy (EBGL, Art. 40(2)). Allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves is done simultaneously with the capacity allocation for the exchange of energy. This method shall apply for the exchange of balancing capacity or sharing of reserves with a contracting period of not more than one day and where the contracting is done not more than one day in advance of the provision of the balancing capacity (EBGL, Art. 40(1)).

A summary of the three approaches is given in Table 3; it can be seen that the co-optimisation approach is the most advanced method, integrating best cross-zonal transmission capacity allocation for the exchange of balancing capacity and sharing of reserves with the capacity allocation for the exchange of energy.

	Based on a comparison of		Timing calculation vs timing of the allocation for the exchange of energy	Method shall apply to	
	Market value of the exchange of energy	Market value of the exchange of balancing capacity or sharing of reserves		Contracting period reserves	Time lag between contracting and delivery of reserves
<i>Economic efficiency analysis</i>	Forecasted	Forecasted	Before	> 1 day	> 1 week
<i>Market-based approach</i>	Forecasted/Actual	Actual/Forecasted	Just before/after	<= 1 day	<= 1 day
<i>Co-optimisation approach</i>	Actual	Actual	Simultaneous	<= 1 day	<= 1 day

Table 3: Summary of the three approaches for cross-zonal capacity calculation for the exchange of balancing capacity or sharing of reserves.

It can be derived from the EBGL that the preferred approach is the co-optimised allocation process. Namely, for an approach based on economic efficiency analysis and a market-based approach, a

¹¹⁶ Art. 39(4) of the EBGL describes that ‘the actual market value of cross-zonal capacity for the sharing of reserves shall be calculated based on the avoided costs of procuring balancing capacity.’

Art. 39(2) of the EBGL describes that ‘the actual market value of cross-zonal capacity for the exchange of energy shall be calculated based on the bids of market participants in the day-ahead markets, and take into account, where relevant and possible, expected bids of market participants in the intraday markets.’

Art. 39(3) of the EBGL describes that ‘the actual market value of cross-zonal capacity for the exchange of balancing capacity shall be calculated based on balancing capacity bids submitted to the capacity procurement optimisation function.’

harmonised methodology may be proposed by all TSOs (Article 41(1) and 42(1)); while for a co-optimised approach a harmonised methodology shall be proposed by all TSOs (Article 40(1)). The latter method is the one best in line with the idea to optimally integrate capacity allocation over time frames and also with the provision to procure balancing capacity on a short-term basis (EBGL, Art. 32(2.b)).

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