**UNIVERSIDAD PONTIFICIA COMILLAS DE MADRID**
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)
Instituto de Investigación Tecnológica

# ADAPTING EUROPEAN MARKET ARRANGEMENTS TO FACILITATE THE CONTRIBUTION OF RENEWABLE GENERATORS TO ELECTRICITY BALANCING

Tesis para la obtención del grado de Doctor

Directores:
Prof. Dr. D. Pablo Frías Marín
Prof. Dr. D. Javier Reneses Guillén

Autor:
Lda. Camila Formozo Fernandes

Madrid 2017

# ABSTRACT

Intermittent renewable generation is increasingly displacing conventional generation units, i.e. traditional suppliers of balancing services, from the daily electricity dispatch. As a consequence, there is a growing need that renewable generators also contribute to electricity balancing so that system operational security is guaranteed at all times. Nevertheless, current European market designs limits the handling of renewable production intermittency through efficient intraday trading and, in several cases, prevent renewable power producers from participating in active and passive electricity balancing. In this respect, the European Commission, together with ACER and ENTSO-E, has developed guidelines for the harmonization of national electricity markets, aiming at eliminating cross-border barriers and facilitating the integration of massive amounts of renewable generation. Although these guidelines establish general principles for the future design of the European electricity market, there are several open issues regarding the most adequate arrangements leading to an efficient integration of renewable production in electricity markets. In this context, this thesis critically analyzes European market arrangements affecting electricity balancing, identifying relevant barriers and providing recommendations for the design of competitive and efficient intraday and balancing markets.

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# ACRONYMS

| | |
|---|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| aFRR | Automatic Frequency Restoration Reserve |
| BRP | Balance Responsible Parties |
| BSP | Balancing Service Provider |
| CACM | Capacity Allocation and Congestion Management |
| CEER | Council of European Energy Regulators |
| CRMs | Capacity Remuneration Mechanisms |
| DA | Day-Ahead |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| FACTS | Flexible AC Transmission System |
| FCR | Frequency Containment Reserve |
| ID | Intraday |
| ISP | Imbalance Settlement Period |
| LIP | Local Implementation Project |
| mFRR | Manual Frequency Restoration Reserve |
| MO | Market Operator |
| RR | Replacement Reserve |
| SO | System Operator |
| XBID | Cross-border Intraday |

# NOMENCLATURE

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| | |
|---|---|
| $BRP$ | Balance responsible party |
| $BSP$ | Balancing service provider |
| $cu$ | Consumption unit |
| $gu$ | Generation unit |
| $h$ | Hour |
| $nt$ | Network tariff |
| $p$ | Period |
| $RA$ | Regulation area |
| $vl$ | Voltage level |

## Parameters

| | |
|---|---|
| $AP_h^{up}$ , $AP_h^{dw}$ | Weighted average prices of activated upward and downward balancing energy from aFRR, mFRR, and RR |
| $BS_{BSP,h}$ | Revenue right or payment obligation assigned to a BSP for the provision of upward or downward balancing energy |
| $dev_h^{loss}$ | Difference between effectively measured transmission and distribution network losses and total estimated losses |
| $dev_h^{rtcm}$ | Imbalance caused by real-time congestion management |
| $dev_h^{syst}$ | System imbalance |
| $dev_{BRP,h}$ | Imbalance calculated for a BRP |
| $dev_{BRP,h}^{cg}$ | Aggregated imbalance of conventional generation units within a same BRP and not incorporated in a regulation area |
| $dev_{BRP,h}^{cu}$ | Aggregated imbalance of consumption units within a same BRP |
| $dev_{BRP,h}^{rg}$ | Aggregated imbalance of technology-specific renewable generation units within a same BRP |
| $dev_{RA,h}$ | Aggregated imbalance of a regulation area |
| $dev_{cu,h}$ | Imbalance of consumption a consumption unit |

| | |
|---|---|
| $dev_{gu,h}$ | Imbalance of consumption a generation unit |
| $Ebal_{bsp,h}$ | Balancing energy provided by a BSP |
| $E_{cu,h}$ | Energy consumed by a consumption unit (without including network losses) |
| $E_{cu,vl,nt,h}$ | Energy consumption measured at the consumption bus |
| $E_{gu,h}$ | Energy produced by a generation unit |
| $eAFRR_{RA,h}^{dw}$ | Downward aFRR energy provided by a regulation area |
| $eAFRR_{RA,h}^{up}$ | Upward aFRR energy provided by a regulation area |
| $eMFRR_{BSP,h}$ | mFRR energy provided by aBSP |
| $eRTCM_h$ | Net amount of redispatched generation |
| $IP_h$ | Imbalance price |
| $IP_h^+$ , $IP_h^-$ | Imbalance prices applied to long (+) and short (-) BRPs |
| $IS_h^{loss}$ | Payment obligation or revenue right associated to the imbalances resulting from the difference between real and estimated network losses ($dev_h^{loss}$) |
| $IS_{BRP,h}$ | Payment obligation or revenue right resulting from the settlement of a BRP's imbalance |
| $Lcoef_{vl,nt,p}$ | Estimated losses' coefficient applied to customers connected to the voltage level $vl$ and settled according to a network tariff $nt$, for period p |
| $Loss_h$ | Measured transmission and distribution network losses |
| $Lrcoef_{cu,vl,nt,h}$ | Real hourly losses' coeficient (calculated expost) |
| $MS_{cu,h}$ | Final (ID) market schedule of a consumption unit |
| $MS_{gu,h}$ | Final (ID) market schedule of a generation unit |
| $OS_{BSP,h}^{eMFRR}$ | Activation of mFRR by the SO from a BSP |
| $OS_{cu,h}$ | Order of consumption reduction assigned to a consumption unit with an interruptible load contract |
| $OS_{gu,h}$ | Upward or downward energy dispatches allocated by the SO to a generation unit up to 15 minutes before real-time for system balancing and/or congestion management purposes |

| | |
|---|---|
| $P_h^{DA}$ | Day-ahead market price |
| $P_h^{Ebal}$ | Price of balancing energy |
| $P_h^{eAFRRdw}$, $P_h^{eMFRRdw}$, $P_h^{eRRdw}$ | Marginal prices of activated downward balancing energy from aFRR, mFRR, and RR, respectively. |
| $P_h^{eAFRRup}$, $P_h^{eMFRRup}$, $P_h^{eRRup}$ | Marginal prices of activated upward balancing energy from aFRR, mFRR, and RR, respectively |
| $PO_{BSP,h}^{eMFRR}$ | Financial penalties for non-compliance with upward or downward mFRR energy allocated by the SO to the deviating BSP |
| $PO_{BSP,h}^{eRR}$ | Financial penalties for non-compliance with upward or downward RR energy allocated by the SO to the deviating BSP |

# Chapter 1: Introduction

This chapter provides a brief background on the chosen research topic. Furthermore, the scope and objectives of the analyses carried out in this thesis are defined. Finally, the outline of this document is also described.

## 1.1. Background

Climate change, competitiveness and security of supply concerns resulted in ambitious **targets** in the EU to reduce CO2 emissions, increase the share of renewable energy, and improve energy efficiency by 20% in 2020 (European Commission, 2009). Furthermore, the EU is committed to reducing greenhouse gas emissions by 80-95% below 1990 levels by 2050. The electricity sector will play a key role in achieving these targets. The EU expects an increase in the share of low carbon technologies in the electricity mix from approximately 45% in 2011 to 60% in 2020, 75-80% in 2030, and nearly 100% in 2050. Out of the 100% target in 2050, 50-55% would come from renewable energy sources (European Commission, 2012).

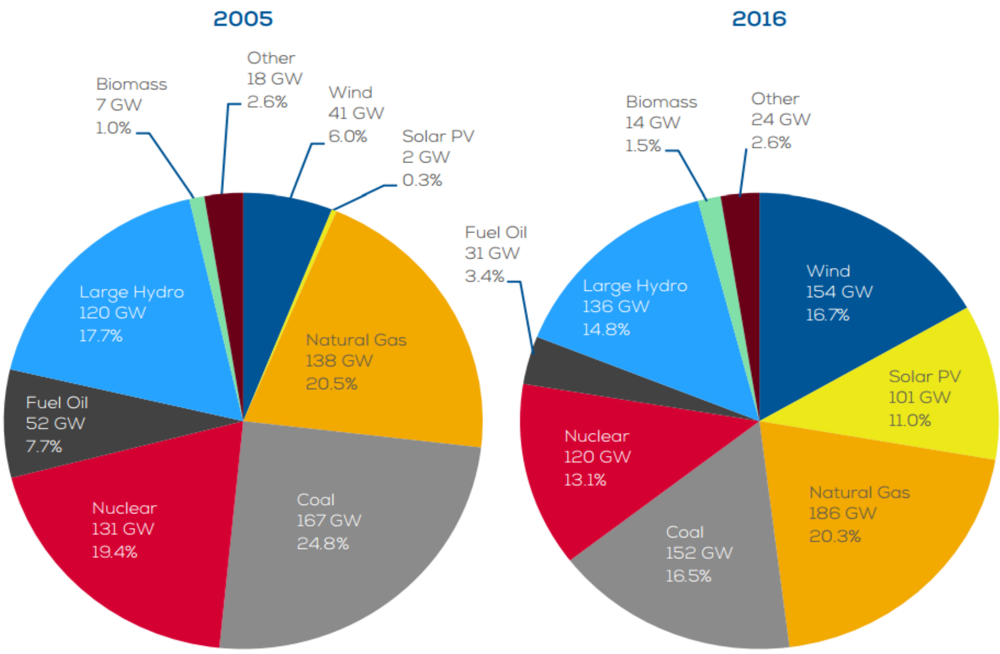



**Figure 1.1: Total installed power capacity in Europe in 2005 and 2016. Source: Wind Europe (2017)**

As a result of these policy goals, **renewable generation**, in particular wind and solar power, has significantly increased in Europe over the last decade and will keep growing within the next years. The share of wind power in total installed power capacity has increased from 6% in 2005 to 16.7% in 2016, overtaking coal as the second largest source of power capacity in the EU, as shown in Figure 1.1. Over the same period wind and solar power together increased their share from approximately 6% to almost 28% of total power capacity.

Increasing amounts of intermittent renewable generation imposes great challenges to the planning and operation of power systems. In order to integrate increasing shares of renewable production, significant national and cross-border **network investments** are necessary, especially if large-scale onshore and offshore wind parks in Northern Europe and large solar power facilities in Southern Europe and Northern Africa are developed (Boie et al., 2014; Fernandes et al., 2013). Moreover, **flexible technologies and mechanisms** are required to cope with renewable generation intermittency, such as Flexible AC Transmission Systems (FACTS), storage, electric vehicles and demand-side management (Fernandes et al., 2013, 2012).

In this sense, one of the main challenges imposed by **renewable energy intermittency** on power system operation refers to the maintenance of the balance between generation and demand at all times (i.e. **electricity balancing**). **Electricity balancing** refers to the role of the System Operator (SO) in ensuring the balance between generation and demand continuously. Electricity balancing involves two main pillars, **active balancing** and **passive balancing** (Chaves-Ávila et al., 2014; Fernandes et al., 2016; Hirth and Ziegenhagen, 2015).

The former refers to the activation of **balancing service providers** (BSPs), i.e. agents which pass qualification tests required for the provision of balancing services. Balancing services is a general term used to describe reserves related to the load-frequency control process, which is performed by the SO in order to maintain the balance between generation and demand in real-time and the power system frequency within a predefined range. In Europe, load-frequency control typically involves three levels of control that operate within different time frames: primary, secondary and tertiary control. To guarantee the adequate provision of reserves related to the frequency control process (i.e. primary, secondary and tertiary reserves), and depending on the power system balancing needs, SOs may define different balancing products. In general, these products can be divided into two main categories:

1. Balancing capacity, which refers to power capacity reserved in advance and kept available to the SO.
2. Balancing energy, which refers to the variation of production/consumption in response to a request from the SO for real-time balancing purposes.

These products can be further divided into two other categories:

i. Upward balancing capacity/balancing energy: balancing capacity/energy procured to compensate a negative system imbalance (i.e. production < consumption).

ii. Downward balancing capacity/balancing energy: balancing capacity/energy procured to compensate a positive system imbalance (i.e. production > consumption).

Passive balancing is related to the concept of balance responsibility, which defines the financial responsibility of market participants for production/consumption deviations in respect to their market schedules, and to the provision of adequate incentives for them to support the system balance. In this sense, market participants are referred to as **balance responsible parties** (BRPs).

Finally, the intraday market also plays a very important role in electricity balancing. The intraday market is held after the gate-closure of the day-ahead market and allows market agents to adjust previous market schedules not only to account for unexpected unit outages or better consumption/production forecasts but also to change their positions (for instance, to account for the commitment of capacity in other markets). In this sense, the intraday market provides market participants with an opportunity to handle unintended imbalances before balancing actions are needed in real-time.

In this respect, several studies have reported an increase in the SO's balancing needs, in particular a higher deployment of balancing energy, related to the integration of intermittent generation such as wind and solar power (Dena, 2010; Gil et al., 2010; Holttinen et al., 2011). The effect of intermittent renewable production on balancing needs depends on a combination of factors, such as the interactions between load and resource availability, resource variability and production forecast errors, and **regulatory/market arrangements, i.e. market rules** (Holttinen et al., 2011).

Regarding the latter, until recently, low-risk **support schemes** (e.g. feed-in tariff) have kept new renewable technologies aside from electricity markets in Europe (Hiroux and Saguan, 2010). In fact, according to CEER (2017), in the period 2014-2015 feed-in tariff schemes still were the most prevalent form of renewable energy support used Europe. Generally, those schemes provides renewable power producers with priority dispatch and exemption from paying balancing costs (i.e. costs related to the procurement of balancing services). Consequently, these generators had an incentive to sell all their available production in the day-ahead and intraday markets, **regardless**

**of the system balancing needs and economic efficiency**. For this reason several countries have adapted their support schemes in order to facilitate a higher and more efficient integration of intermittent renewable generation (CEER, 2017).

As for **market arrangements**, their influence on the impact of renewable production on balancing needs is mainly related to the discrepancies between the power forecasted at the last market gate-closure and real-time production. Since the intraday timeframe represents the last gate-closure for energy trading before balancing actions are required, **intraday markets** plays a very relevant role in facilitating the integration of intermittent generation (Borggrefe and Neuhoff, 2011; Weber, 2010).

Furthermore, concerns regarding the increasing penetration of renewable generation and the continuous displacement of conventional generation units – i.e. traditional suppliers of balancing services – from the daily electricity dispatch have been calling attention to the need for adaptation of **balancing arrangements** to the participation intermittent power producers and other potential suppliers in electricity balancing (Hirth and Ziegenhagen, 2015; Rivier, 2010; Saiz et al., 2012; Vandezande et al., 2010).

Therefore, an adequate design of intraday and balancing market arrangements is essential for an efficient integration of intermittent renewable production into power systems (Chaves-Ávila and Fernandes, 2014; Fernandes et al., 2016). In this context, the European Commission, together with the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E), has developed **guidelines for the harmonization of national electricity markets**, aiming at eliminating cross-border barriers and facilitating the integration of massive amounts of renewable generation. Although these guidelines establish general principles for the design of the future European Electricity Market, there are several open issues regarding the most adequate arrangements leading to an efficient integration of renewable production in electricity markets.

## 1.2. Scope and objectives of the thesis

According to (ACER, 2014), the core elements that are needed in order to achieve an efficient European balancing market, while taking into account security of supply constraints, are related to: (i) a consistent framework to foster **competition among BSPs**, (ii) **adequate incentives on BRPs** to balance to support the system balance in real-time, and (iii) **efficiency in balancing actions** taken by SOs. These elements are closely related to flexible balancing market designs, which foster competition among BSPs and market efficiency; cost-reflective imbalance settlement arrangements, which provide incentives BRPs to support the system balance in real-time; and the existence of liquid intraday markets, which contributes to electricity balancing efficiency.

Taking into account the principles established in the guidelines set by the European Commission and the integration of massive amounts of renewable generation, the **main objective of this thesis** is to analyze current market arrangements affecting electricity balancing and to propose recommendations for European policy markets on the design of the future European balancing market.

This general objective can be broken down into the following specific objectives:

I. To define **electricity balancing** under the context of significant penetration of renewable generation and provide a complete background on **current European market arrangements** affecting the system balancing.

II. To perform an in-depth study on **imbalance settlement arrangements** in order to identify those leading to the calculation of cost-reflective imbalance prices and providing incentives for adequate passive balancing.

III. To carry out a detailed analysis on **balancing market design options** in order to identify arrangements facilitating the entrance of new potential balancing services' suppliers, in particular renewable producers.

IV. To analyze intraday market design options in order to identify solutions leading to higher trading opportunities facilitating the balance of intermittent production through intraday trading.

In order to pursue these objectives, theoretical and empirical analyses are carried out. Due to the existence of similar arrangements in other European countries and the availability of plenty of public data, most empirical analyses are based on **Spanish market** data. Furthermore, the Spanish case is a very relevant example in this research field since it has successfully integrated, so far, a significant amount of intermittent renewable production (25% of electricity demand in 2016 was covered by wind and solar power), in particular taking into account its limited interconnection capacity with Europe. This success is related, from a technical point of view, to the adaption of grid codes and technical requirements regarding to the connection of renewable installations to the power grid; and, from an economic point of view, to the constant evolution of regulatory schemes and incentives towards market integration. In this respect, in 2016 renewable generators started participating actively in balancing market as providers of balancing services.

In this sense, further and more efficient integration of renewable production will depend on the existence of market arrangements that allow these producers to support the system balance by trading intraday markets and participating in active and passive electricity balancing. Furthermore, lessons from the Spanish experience can serve as example for European policy makers.

## 1.3. Outline of the document

In order to address the previous objectives, this document is organized into six chapters. Besides this introductory chapter, the thesis comprises four self-contained chapters (Chapters 2, 3, 4 and 5), which are described below:

**Chapter 2** provides a complete understanding of electricity balancing and the corresponding market design options. Furthermore, it presents the European Target Model on the Internal Electricity Market and the current status of development of the Guideline on Electricity Balancing.

**Chapter 3** identifies adequate imbalance settlement arrangements leading to the calculation of cost-reflective imbalance prices. Cost-reflective imbalance prices incentivize effective passive balancing, which in turn facilitates the contribution from renewable generators to electricity balancing. Numerical examples and empirical analyses using data from the Spanish market are carried out to support the discussion.

**Chapter 4** discusses alternative arrangements for the design balancing markets aiming at identifying those facilitating the contribution of renewable producers to active balancing. In this chapter, empirical data regarding Spanish market outcomes are also used to support the discussion. Based on these analyses, recommendations for the improvement of European balancing market arrangements are proposed.

**Chapter 5** analyzes intraday market design options, taking into account the proposals currently under discussion by the ENTSO-E and national/regional market operators for the European Target Model, in order to identify best-practices and derive policy recommendations for an efficient integration of renewable generation in European power systems.

Finally, **Chapter 6** presents the major conclusions drawn from the work presented in the previous chapters, as well as a summary of the original contributions of the thesis and the identified future research lines.

# Chapter 2: Electricity balancing and European market arrangements

As explained in Chapter 1, the main goal of thesis to provide recommendations for policy makers on the future design of European balancing mechanisms, including intraday trading, which must facilitate the contribution of renewable power producers and other potential providers to electricity balancing, thus enabling an efficient integration of clean intermittent generation in Europe. To this aim, this chapter provides a complete understanding of electricity balancing and analyses corresponding market design options. Furthermore, it presents the European Target Model on the Internal Electricity Market and the current status of development of the Guideline on Electricity Balancing. This chapter sets the basis for the analyses to be carried out in Chapters 3, 4 and 5 and it is divided into four main sections:

I. First, a brief overview of the current organization of European electricity markets is provided.

II. After that, electricity balancing concepts are defined.

III. Then, market design options related to electricity balancing are briefly discussed.

IV. Finally, the European Target Model on the Internal Electricity Market is introduced and the current status of the Guideline Electricity Balancing is commented on.

## 2.1. Organization of European electricity markets

Until the late 1980's electricity was typically supplied by vertically integrated power companies who were the ultimate responsible for the quality and security of electricity delivery. For this service, these companies received a regulated remuneration based on their investment and operation costs. With the liberalization of the electricity sector, which aimed at introducing competition as precondition for an efficient energy supply, electricity started being traded in markets managed by the **market operator** – MO – while the responsibility for guaranteeing quality and security of supply was transferred to the **system operator** – SO (Soler, 2001).

The organization of current **European electricity markets** can be explained by the definition of different "products" needed in order to guarantee an efficient and secure electricity supply, which requires the continuous balance between generation and demand. Batlle and Rodilla (2010) decouple security of electricity supply into four major components from a time-dimension perspective:

- Very long term: strategic expansion policy. This component is mainly related to the availability of energy resources – diversification of technology generation mix and fuel provision – and adequate (transmission) infrastructure.
- Long term: adequacy. This component is related to the availability of enough generation capacity to supply electricity demand in the long-term.
- Mid to short term: firmness. This is related to the efficient delivery of electricity by existing facilities, which depends on the adequate management of primary resource provision (such as gas and oil supply contracts), hydro-thermal coordination, maintenance scheduling of nuclear power plants, etc.
- Very short term: operational security. This is related to the ability of the power system to support unexpected disturbances due to generation/network elements outages and/or variations of demand and renewable production during real-time operation.

Strategic expansion policy is decided by policy makers and it is generally tackled by regulated mechanisms, whenever these are needed to reach a specific policy objective, such as support schemes for renewable generation or fixed prices for units powered by domestic fuel. In Europe, adequacy is typically guaranteed by capacity remuneration mechanisms (CRMs), which aim at providing direct incentives to market agents to invest in generation capacity[1]. As an alternative, some power systems rely on energy-only markets, which are based on the principle that, in the absence of market failures, investment and operation costs of power plants should be recovered exclusively through market prices (Browne et al., 2015).

Firmness can be associated with the product "energy", which is negotiated either in markets organized by the MO or through bilateral contracts. Contracts such as **futures or forwards** traded in organized markets or bilaterally over the counter, with either physical or financial settlement, allow for hedging against price uncertainties which characterize spot markets. The duration of these contracts may vary from days up to years (Redl et al., 2009). The MO also operates the day-ahead and intraday markets. The **day-ahead market** is the market where qualified consumers and producers buy and sell electricity for the 24 hours of the following day, i.e. the operation day. After the gate-closure of the day-ahead market, agents can adjust previous market schedules, not only to account for unexpected unit outages or better consumption/production forecasts but also to change their positions (for instance, to account for the commitment of capacity in other markets), in the **intraday market**.

Finally, operational security is guaranteed by the SO through congestion management and electricity balancing. **Congestion management** is performed by the SO whenever energy market schedules do not comply with network security criteria. In general, when grid constraints are detected, the SO uses bids from (constrained-off) generators to reduce (or stop) production and bids from (constrained-on) units to increase (or start) production (van Blijswijk and de Vries, 2012). **Electricity balancing** refers to the role of SOs in ensuring the balance between generation and demand continuously (discussed in detail in Section 2.2).

Figure 2.1 presents the typical sequence of European electricity markets. Forward contracts can be negotiated for a period of years, months, weeks or days. The day-ahead market is held on the day before the operation day. Intraday trading is possible from after the gate-closure of the day-ahead market until shortly before real-time, depending on the market design (see subsection 2.1.1). In general, congestions are managed by the SO once energy schedules are modified – i.e. after the closures of the day-ahead and intraday markets – and during real-time operation. Finally,

[1]ACER (2013) provides an overview of the main CRM designs and discusses market distortions that may be caused by these types of mechanisms.

balancing actions are typically taken after the gate-closure of the intraday market and during real-time operation.

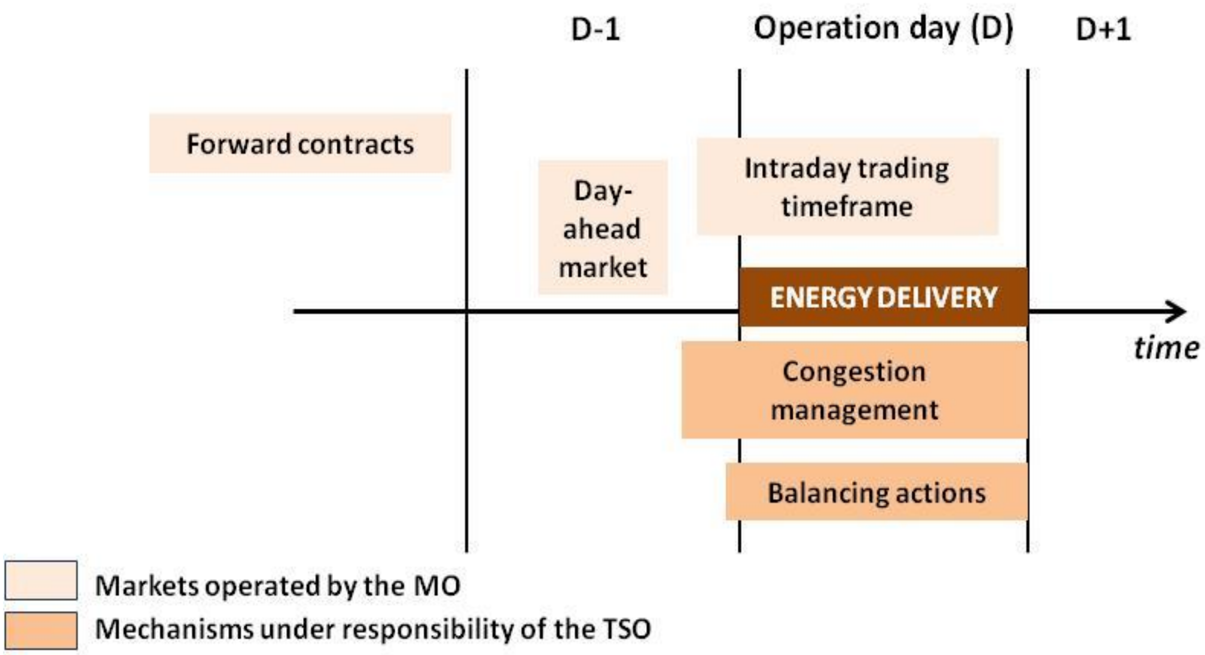



**Figure 2.1: Typical sequence of electricity markets. Source: own elaboration.**

Due to interactions between intraday trading and balancing actions and between the latter and congestion management, intraday markets and congestion management are further described in subsections 2.1.1 and 2.1.2, respectively.

### 2.1.1. **Intraday markets**

Currently, two main intraday market designs are used in Europe: continuous and discrete intraday trading (Weber, 2010). Under **continuous intraday trading** market participants are able to access bids from other market participants in a continuous manner. The continuous intraday market platform opens after the gate-closure of the day-ahead market and closes shortly before real-time operation (from one hour up to 15 minutes before real-time, as shown in Figure 2.2). Under this market design, buy and sell bids can be selected as soon as they become available (i.e. bids are matched continuously) and up to the market's gate-closure. Trade is done on a first-come first-served principle where the highest buy price and the lowest sell price get served first. Prices are set according to the sell bid price (i.e. pay-as-bid pricing). Continuous trading is the market design used in the majority of European countries and it is the target model for the European intraday market established by the Guideline on Capacity Allocation and Congestion Management (European Commission, 2015).

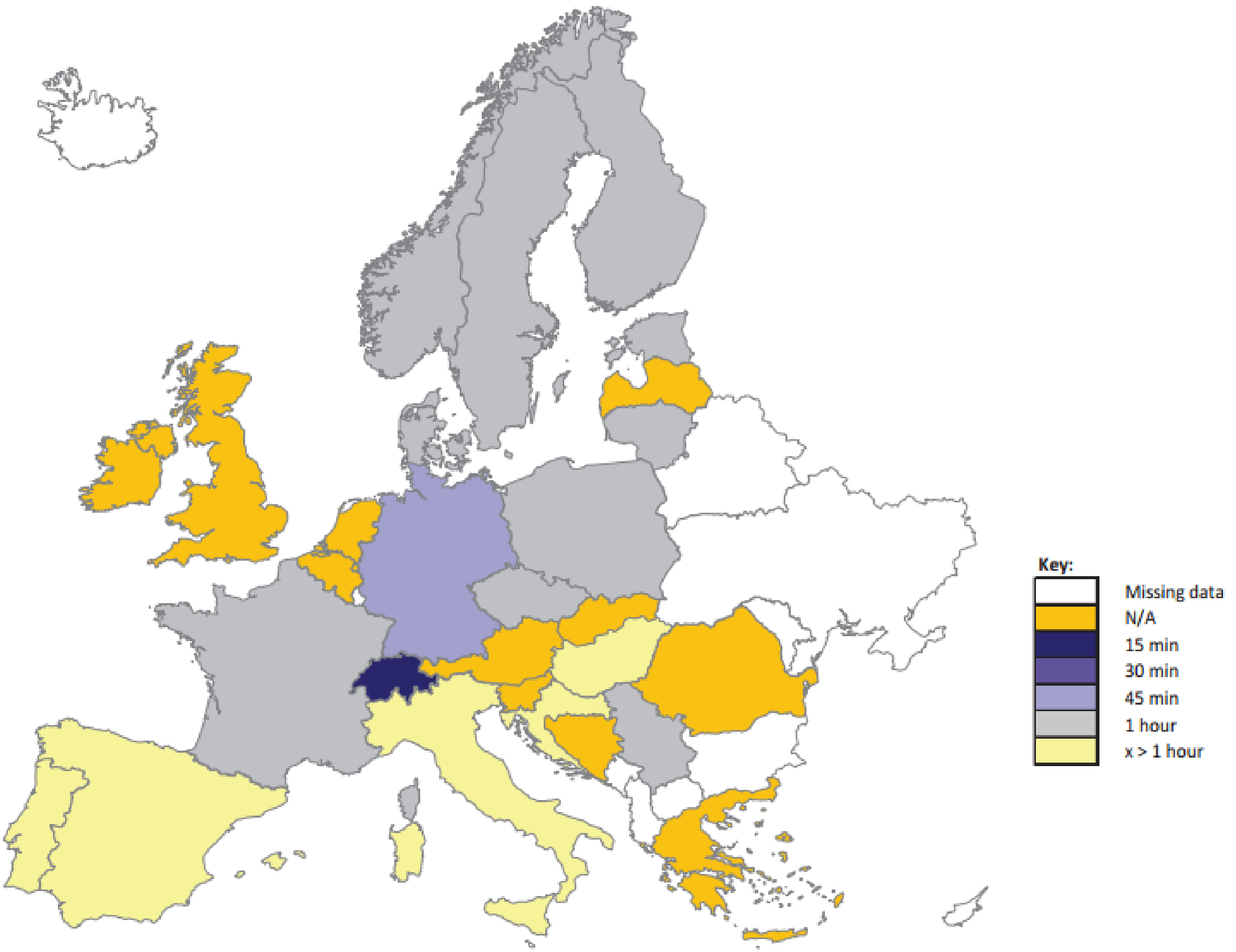



**Figure 2.2: Intraday market gate-closure lead-times. Source: ENTSO-E (2015).**

Intraday trading also takes place in **discrete intraday auctions.** This intraday market design is currently used in the Iberian Peninsula (Portugal and Spain) and Italy. The intraday market of Portugal and Spain consists of seven intraday auctions while the Italian one comprises six auctions. Each one of these sessions has a specific energy scheduling horizon – i.e. number of delivery periods for which energy is traded. Under this market design, bids are collected between the auction gate-opening and gate-closure times and the most competitive ones are matched together after the auction is closed. Depending on the delivery hour, the lead-times of the Iberian intraday market varies between 3.25 and 7.25 hours, while the Italian intraday market lead-times varies between 2.25 and 9.5 hours. In these intraday markets, prices are set at the marginal market price for each trading period.

In theory, continuous intraday markets provide a transparent trading platform for market agents to clear their open positions as soon as they occur since bids can be introduced and seen by all participants in a continuous manner. This, together with gate-closures closer to energy delivery time, would allow market agents – especially renewable generators – to reduce significantly imbalance costs. On the other hand, trades in continuous markets are in general dispersed over the whole trading period, which reduces the liquidity of the market. In this respect, liquidity is generally it is understood as the easiness of trading a particular asset for which different measurement concepts have been proposed (Goyenko et al., 2009). Weber (2010) points out that the easiness of trading is an increasing function of the number of market participants and trades; consequently, a typically used indicator for liquidity in financial and energy markets is the volume of trades. Hereinafter, the term liquidity is applied to refer mainly to market trading volumes.

Despite the longer lead-times of discrete intraday markets, discrete auctions centralizes energy trading at specific points in time, increasing market liquidity and allowing higher volumes of energy to be traded. Figure 2.3 presents intraday traded volumes as a percentage of electricity demand in EU markets during the period 2011-2015.

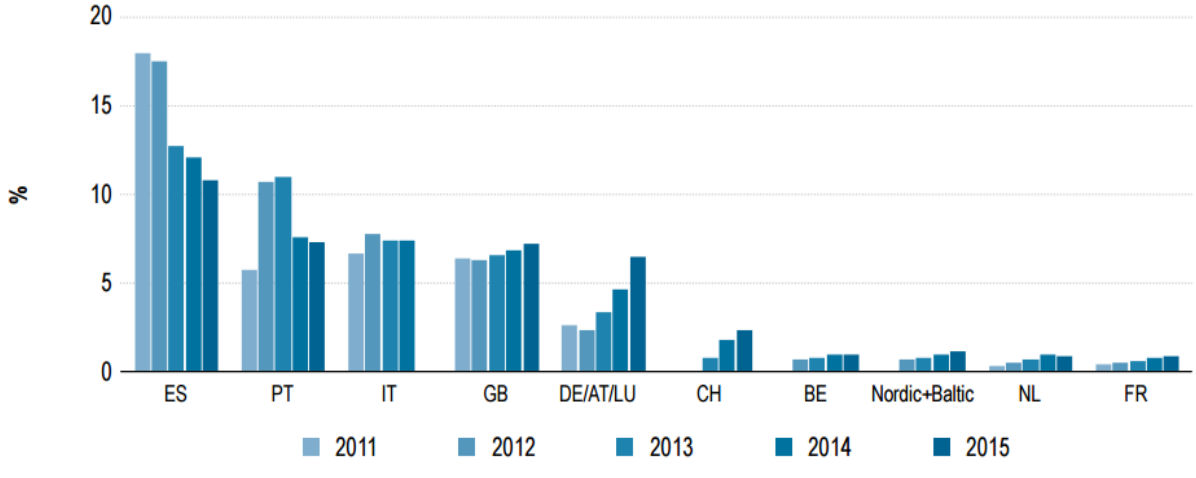



**Figure 2.3: Intraday traded volumes as a percentage of electricity demand in EU markets – 2011–2015 (%). Source: ACER and CEER (2016)**

It can be observed that, apart from the Great Britain and the German-Austrian markets, continuous intraday trading present much lower liquidity levels in comparison to discrete intraday markets implemented in Spain, Portugal and Italy. Regarding the Great Britain and the German markets, it is worth pointing out that volumes traded in the day-ahead market represent approximately 20% and 40% of electricity consumption in these countries, respectively, while in Spain this share is around 75%.

Liquid intraday markets are especially relevant in power systems with high penetration of intermittent generation since these producers are subjected to larger energy imbalances when compared to conventional generators[2].

The influence of intraday trading on electricity balancing is related to the fact that the intraday trading timeframe represents the last gate-closure for energy trade before balancing actions are required. In the presence of adequate liquidity levels and gate-closure times close to delivery, intraday markets play an essential role in reducing imbalances and, consequently, the activation of (more expensive) balancing resources. Due to the strong relationship between intraday trading and electricity balancing, **intraday market design options** are further discussed in Chapter 5.

### 2.1.2. **Congestion management**

Since nodal prices are not applied in Europe, network congestions occurring within bidding zones – i.e. geographical areas within which market participants are able to exchange energy without transmission capacity allocation – is managed by the SO through generation redispatch. **Generation redispatch** is a remedial action by which the SO modifies generation and/or consumption units schedules in order to change transmission power flows and relieve network congestions. As previously explained, when grid constraints are detected, the SO requests some generators (or certain consumers) to start or increase production (or reduce consumption), and some other generators to stop or reduce production (or increase consumption), in order to maintain network security (ACER and CEER, 2014).

[2]A detailed analysis of the participation of renewable producers in the Spanish intraday market is performed by Chaves-Ávila and Fernandes (2014).

In general, after the gate-closure of the day-ahead market, SOs collect bids from generators and/or consumption units for solving network constraints and select the least expensive bids from constrained-on generators and accepts bids from constrained-off generators who are willing to pay more to reduce production. During real-time operation, SOs typically activate balancing energy bids to solve congestions (ENTSO-E, 2015). As it will be discussed in Section 2.2.2, activated balancing energy has a direct impact on the computation of imbalance prices. Consequently, balancing energy bids activated for/related to congestion management purposes may have important implications on balancing mechanisms. **Interactions between congestion management and balancing mechanisms** are further discussed in Chapter 3.

## 2.2. Electricity balancing

The European Network of Transmission System Operators for Electricity (ENTSO-E) defines electricity balancing as all actions and processes, in all timeframes, through which SOs ensure the balance between generation and demand in a continuous way in order to maintain the system frequency within a predefined stability range (ENTSO-E, 2014a). Electricity balancing involves two main pillars, **active balancing** and **passive balancing** (Chaves-Ávila et al., 2014; Fernandes et al., 2016; Hirth and Ziegenhagen, 2015). The former refers to the activation of **balancing service providers** (BSPs) by the SO for balancing purposes. The latter is related to the concept of balance responsibility, which defines the financial responsibility of market agents – i.e. **balance responsible parties** (BRPs) – for production/consumption deviations in respect to their market schedules, and to the provision of adequate incentives for those agents to support the system balance. Notice that **intraday trading** can be directly related to passive balancing since this is the intraday trading timeframe is last gate-closure for schedules adjustments before balancing actions are taken in real/time.

### 2.2.1. Active balancing

The processes by which SOs maintain the system frequency within a predefined range is commonly referred as **load-frequency control**. In Europe, these processes related to load-frequency control are defined by the Network Code on Load-Frequency Control & Reserves – NC LCFR – (ENTSO-E, 2013a). These processes are summarized below and illustrated in Figure 2.4.

- Primary Control (Frequency Containment Process): this process aims at stabilizing the system frequency at a stationary value after a disturbance (e.g. large generation or load outages) by a joint action of primary reserve available within a synchronous area[3]. Primary control can be performed by synchronized generators equipped with a speed governor and by demand through the connection/disconnection of loads at given frequency levels. Primary reserve is activated within a few seconds after the disturbance has occurred and must be fully operational within the required full activation time, which varies between 10 to 30 seconds, depending on requirements of each synchronous area. Following the definitions set in the NC LFCR, hereinafter primary reserve will be referred as **Frequency Containment Reserve** (**FCR**).

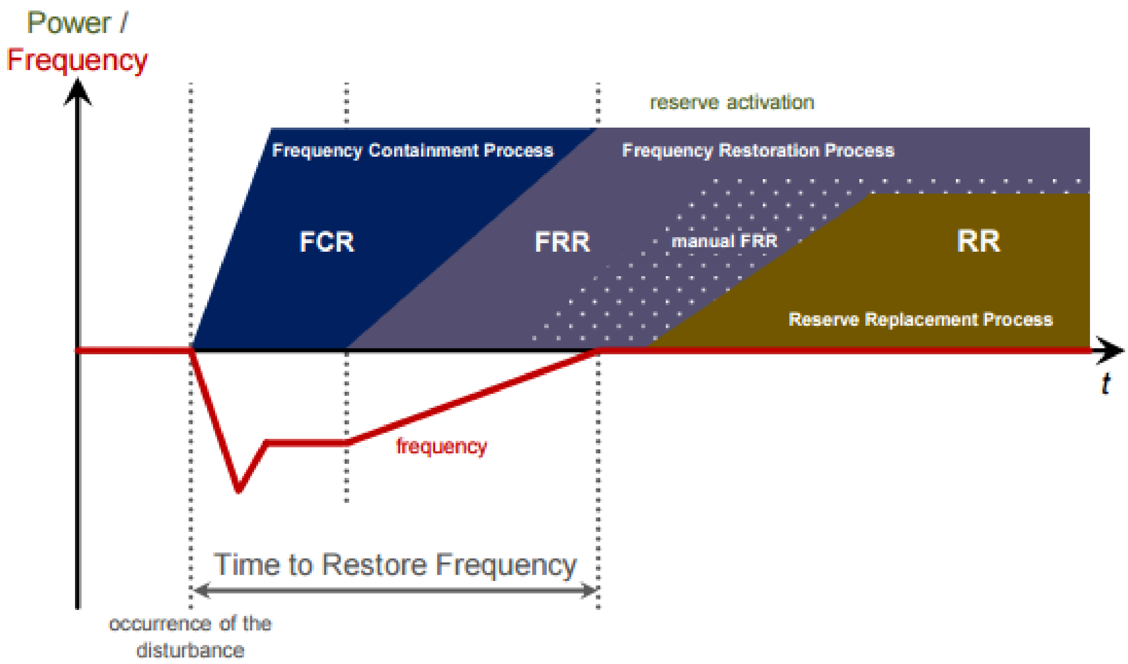



**Figure 2.4: Load-Frequency control processes in Europe. Source: ENTSO-E (2013b)**

- Secondary Control (Frequency Restoration Process): this process aims at bringing back the system frequency to its nominal value and replacing the activated FCR through the activation of secondary reserve. In general, secondary reserve is activated by an automatic generation control which modifies active power set points of generation

[3]The ENTSO-E is composed by five permanent regional groups (RG) each one corresponding to a synchronous area: RG Continental Europe (RG CE), RG Nordic, RG Baltic, RG UK, and RG Ireland.

and/or controllable load units. Secondary reserve is typically activated within 30 seconds after the contingency event and must be fully operational within 15 minutes. Following the definitions set in the NC LFCR, hereinafter secondary reserve will be referred as **automatic Frequency Restoration Reserve** (**aFRR**).

- Tertiary control (Reserve Replacement Process): this process refers to the activation of Tertiary Reserve to replace and/or support the activation of aFRR, preparing the system to deal with large imbalances and/or sustained demand/renewable generation variation. Tertiary control is manually activated and must be fully available within 15 minutes of activation. According to ENTSO-E (2013b), tertiary control can be divided between **directly activated tertiary control** – i.e. tertiary reserve which can be activated within any time within the delivery period – and **scheduled activated tertiary control** – i.e. tertiary reserve which is activated in relation to a pre-defined delivery period or delivery horizon (one or more delivery periods). The former is related to the Frequency Restoration Process and the latter with the Reserve Replacement process. According to the definitions set in the NC LFCR, those reserves will be referred as **manual Frequency Restoration Reserve** (**mFRR**) and **Replacement Reserve** (**RR**), respectively.

Reserves used for load-frequency control purposes – i.e. FCR, FRR, and RR – are commonly referred as balancing services. Depending on the (balancing) needs of each power system, SOs may define different **balancing products** related to those services. In order to guarantee the adequate provision of balancing services, SOs typically procure balancing products through specific markets, commonly referred as **balancing markets**[4]. Depending on market arrangements, not all of the above mentioned products are procured separately (further discussed in Section 2.3.1.1. In general, balancing products can be divided into two main categories:

1. **Balancing capacity**, which refers to power capacity reserved in advance and kept available to the SO (i.e. not committed in other markets) for its use when deviations between generation and demand occur during real-time operation.

[4]Notice that, apart from balancing markets, other methods of procuring balancing products are still used in some European countries and/or for certain balancing services. Examples of these are compulsory provision and bilateral contracts. In the former case, all BSPs are obliged to provide a certain balancing product for which they received a regulated remuneration or are not remunerated. In the latter case, SOs negotiate directly with BSPs the quantity, the quality and the price of the product to be provided. Surveys on these type of procurement schemes can be found in ENTSO-E (2014b) and Rebours et al. (2007).

2. **Balancing energy**, which refers to the actual variation of production/consumption aimed at reestablishing the balance between generation and demand during real-time operation.

These products can be subdivided into two further categories:

i. **Upward/positive** balancing energy (or capacity): product procured to compensate (or safeguard the system against) a negative imbalance (i.e. lack of generation or excess of consumption). In both cases of "capacity" and "energy", BSPs sell upward products to the SO.
ii. **Downward/negative** balancing energy (or capacity): product procured to compensate (or safeguard the system against) a positive imbalance (i.e. generation surplus or reduced consumption). In the case of the product "capacity", BSPs sell downward balancing capacity to the SO and, in the case of the product "energy", BSPs buy energy from the SO.

Although the reservation of balancing capacity may be required for real-time balancing purposes, SOs procure balancing capacity in order to safeguard system operational security, guaranteeing the provision of sufficient balancing energy during real-time operation in case large imbalances and/or contingencies (e.g. large generation outage) occur during real-time. Consequently, balancing capacity cannot be directly related to (actual) real-time imbalances. In fact, during most of the time, contracted balancing capacity is not fully deployed. On the other hand, balancing energy can be directly attributed to balancing actions. In this respect, Grande et al. (2008) define **active balancing** as "*changes in production or consumption on a request from the SO to activate their bid in the balance market*".

Despite this, balancing capacity and balancing energy products are jointly procured in several European countries. The fact that balancing capacity is typically procured far ahead of real-time imposes a strong barrier to the contribution of renewable generation and other new market players in active balancing. Furthermore, balancing markets in general have been designed based on the characteristics of traditional suppliers of balancing services, i.e. conventional generators, limiting the participation of other potential suppliers in these markets. In this respect, Section 2.3.1 briefly introduces balancing market design options, which are further analyzed in Chapter 4.

### 2.2.2. **Passive balancing**

In order to keep balancing resources available, SOs incur in **balancing costs**. These costs are related to the settlement of BSPs, which typically involves a **capacity payment** (in €/MW), corresponding to the reservation of balancing capacity, and an **energy component** (in €/MWh) corresponding to the delivery of balancing energy during real-time operation.

Regarding the former, BSPs providing balancing capacity receive the balancing capacity price regardless its activation during real-time operation; as for the energy component, BSPs providing upward balancing energy receive the corresponding price from the SO and BSPs providing downward balancing energy pay the corresponding price to the SO. Notice that, in several power systems, BSPs may bid negative prices for the provision of (downward) balancing energy. If the downward balancing energy price is negative, the direction of the payment flow changes (i.e. BSPs providing downward balancing energy receive the corresponding price from the SO).

While the payments associated to the provision of balancing energy depend on duration of imbalances (i.e. the period of balancing energy delivery), payments associated to the provision of balancing capacity are made beforehand and for a time period far exceeding the duration of imbalances (Vandezande et al., 2010). As previously mentioned, SOs generally dimension balancing capacity needs based on security criteria – e.g. risk of a large generator or load outage. For this reason, balancing capacity costs cannot be directly attributed to real-time imbalances (and to imbalanced BRPs) and are typically socialized among consumers through regulated tariffs (ENTSO-E, 2015)[5]. On the other hand, balancing energy costs are allocated to imbalanced BRPs through the **imbalance price**.

In this respect, agents with negative imbalances (**short BRPs**) – i.e. units whose actual production (consumption) levels are lower (higher) than market schedules – pay the imbalance price since they "buy" energy in the balancing market. On the other hand, agents with positive imbalances (**long BRPs**) – i.e. units whose actual production (consumption) levels are higher (lower) than market schedules – receive the imbalance price since they "sell" energy in balancing market. Notice that when the imbalance price is negative (due to negative balancing energy prices),

[5]Haring et al. (2015) propose a separate scheme to allocate costs related to balancing capacity to BRPs.

the direction of flows of payment changes (i.e. long BRPs pay the imbalance price to the SO and short BRPs receive the imbalance price from the SO).

The imbalance price applied to BRPs that aggravate the system imbalance depends on the **system balance state**: if the system is short – i.e. if the net amount of deployed balancing energy is positive – the imbalance price is computed based on the price of upward balancing energy; if the system is long – i.e. if the net amount of deployed balancing energy is negative – the imbalance price is computed based on the price of downward balancing energy. Depending on pricing arrangements, BRPs that reduce the system imbalance are settled either at the same price applied to BRPs aggravating the system imbalance or at the wholesale market price (typically, the day-ahead market price).

Since, in general, upward balancing energy prices are higher than wholesale market prices and downward balancing energy prices are lower than wholesale prices[6], **BRPs aggravating** the system imbalance are financially penalized for their imbalances; **BRPs reducing** the system imbalance are either financially neutral (in respect to the wholesale market price) or financially rewarded for their imbalances, depending on the imbalance pricing system adopted (further discussed in Chapter 3).

In general, the aim of the **imbalance settlement** – which defines the rules for the calculation and application of imbalance prices – is to provide incentives for BRPs to trade efficiently at the forward stage to balance their positions as much as possible up to the intraday trading timeframe – i.e. self-balancing[7]. Typically, two main arrangements are used in order to reinforce self-balancing: i) legal obligation on BRPs to follow their market schedules; and ii) no information regarding the system balance state is provided in real-time.

Incentives for self-balancing were set in context under which imbalances between generation and demand were mainly related to load forecast errors and, to a lower degree, to power system equipment failure. During the last years, however, an additional source of imbalances has been increasing the need for balancing actions: intermittent renewable production forecast errors.

[6]In power systems where thermal power plants participate in balancing services provision, typically, prices of upward balancing energy are higher than DA market prices and prices of downward balancing energy are lower than DA market prices (Vandezande et al., 2010).
[7]In this respect, BRPs will strive for balanced positions as long as the costs of self-balancing are lower than the expected costs of being out of balance (i.e. imbalance price).

In this context, the concept of **passive balancing** – defined by Grande et al. (2008) as "*the contribution to system balancing without having been requested by the SO*" –emerges as an alternative way of supporting the system balance.

According to this definition, passive balancing includes two main concepts: i) BRPs minimizing imbalances by trading up the last market gate-closure (self-balancing) and ii) BRPs supporting the system balance by deviating in the opposite direction of the system overall imbalance. Although the latter concept is not new – Beune and Nobel (2001) relates imbalances in the opposite direction of the system imbalance to passive contribution to electricity balancing – the idea of incentivizing BRPs to voluntarily reduce the system imbalance was first introduced by the Dutch SO in the late 2000s by sharing real-time information regarding the system balance state and balance energy prices with market participants (TENNET, 2011)[8].

In this respect, apart from real-time information regarding the system balance state and imbalance prices, a main condition to passive balancing is the existence of **cost-reflective imbalance prices**; without cost-reflective imbalance prices, BRPs may have distorted incentives and worsen the system imbalance. Imbalance price cost-reflectiveness depends on the definition of adequate **imbalance settlement arrangements** – i.e. definition of system overall imbalance, imbalance settlement period and imbalance pricing. These arrangements are briefly described in 2.3.2 and discussed in detail in Chapter 3.

## 2.3. **Balancing arrangements**

Balancing arrangements establish market-based management of the role of the SO in ensuring electricity balancing (ENTSO-E, 2014a). These arrangements are related to the **procurement of balancing products** – balancing capacity and balancing energy – and to the **imbalance settlement**.

Balancing arrangements have been first defined with the liberalization of the electricity sector since, prior to the liberalization, vertically integrated companies were the responsible for ensuring security of supply. By that time, power systems were composed mainly of conventional

[8]By 2005, the Dutch SO started publishing activated volumes of balancing energy every minute and by 2010 it included price information.

"controllable" generators and renewable production intermittency was not a relevant issue. Consequently, balancing arrangements have been designed based on the technical characteristics of those generators and, due to structural differences of power systems, based on specific balancing needs (Rebours et al., 2007).

Due to the intrinsic characteristics of renewable generation, such as variability and limited predictability, current balancing arrangements may limit renewable power producers and other potential providers, such as demand response, from contributing to electricity balancing, limiting efficiency in balancing markets and the integration of renewable production (Fernandes et al., 2016). In the following subsections balancing arrangements are briefly discussed.

### 2.3.1. **Balancing market arrangements**

As explained in Section 2.2.1, in order to guarantee the adequate provision of balancing services – i.e. FCR, aFRR, mFRR, and RR – SOs may define balancing capacity and/or balancing energy products to be procured in balancing markets. The definition of balancing products and corresponding market arrangements is mainly related to the technical characteristics of the balancing service they refer to and to the costs incurred by BSPs when providing each product.

In this respect, **balancing capacity provision costs** are related mainly to the cost incurred by BSPs when operating below or above their optimum output levels. For instance, BSPs may incur an opportunity cost when providing upward capacity (e.g. opportunity cost of not selling power in the day-ahead market instead) or have an economic loss for selling power as a price taker in order to provide upward and/or downward capacity. **Balancing energy provision costs** refer to the costs incurred by BSPs due to variations in production/consumption levels.

According to a detailed analysis performed by Soler (2001) on the costs of the provision of balancing services, due to the fast response time of the frequency containment process, generation units can provide FCR capacity even when they are operating at a level close to their maximum output. Furthermore, the joint application of this control within ENTSO-E's synchronous areas, together with the fast replacement of FCR with FRR, makes the utilization of FCR to be much reduced in comparison to other types of reserves – i.e. FRR and RR. Consequently, mechanisms for the procurement of FCR products are less developed. For instance, in countries such as Portugal and Spain the provision of FCR is mandatory and non-remunerated; in France, provision of FCR capacity is mandatory and BSPs are settled according a regulated remuneration; finally, countries such as Belgium, Germany or the Netherlands procure FCR capacity through organized markets. However, in none of these countries FCR activation is remunerated or used in the calculation of imbalances and imbalance prices.

Regarding FRR, the fast response time of the frequency restoration process, together with the longer deployment time of aFRR when compared to FCR, requires that synchronized aFRR capacity is reserved and kept available to the SO in case balancing actions are needed during real-time operation. For this reason, in most European countries aFRR balancing capacity is procured through organized markets. In general, aFRR balancing energy procurement is associated to balancing capacity contracts – i.e. there is no specific market for the procurement of aFRR energy and only BSPs with contracts for the provision of aFRR balancing capacity are activated in real-time.

Finally, due to the slower activation time of the reserve replacement process, in some countries – for instance, Portugal and Italy – mFRR and/or RR capacity is not remunerated. In Spain, until recently, there was no specific market for the procurement of these types of mFRR and/or RR capacity. On the other hand, most European countries have specific markets for the procurement of mFRR and/or RR balancing energy.

#### 2.3.1.1. **Procurement of balancing products**

Balancing capacity and balancing energy products can be procured either jointly or separately. If **separated markets** exist for the **procurement of balancing capacity** and for the **activation of balancing energy**, BSPs can choose to participate in the capacity market and, if awarded a contract, they must offer at least the whole amount of the committed capacity to the "activation" (i.e. balancing energy) market. These BSPs are entitled to a capacity payment and, if activated in the energy market, are also settled according to the energy price (see Section 2.2.1). Notice that under this market arrangement, BSPs with a contract for the provision of balancing capacity have the obligation to offer balancing energy in the "activation" market. BSPs without a contract for the provision of balancing capacity can also send bids to the energy market. In real-time, the cheapest balancing resources are activated.

Conversely, **joint procurement of balancing capacity and balancing energy** refers to a market design where only BSPs with a contract for the provision of balancing capacity provide balancing energy. One of the main drawbacks of the latter design is that balancing capacity is typically procured far ahead of real-time operation, which may prevent providers such as renewable generators to participate in active balancing, undermining competition in balancing markets. Another important disadvantage of joint procurement of capacity and energy products is related to the fact that balancing capacity provision costs and balancing energy provision costs can differ greatly for different BSPs. This means that BSPs that face lower capacity costs and, consequently, are committed in the capacity market, may incur in higher balancing energy provision costs than other potential suppliers which were not awarded a capacity contract and, consequently, cannot be activated in real-time. Therefore, this arrangement may lead to inefficient market outcomes.

Regarding the capacity products, **joint procurement of upward and downward balancing capacity** refers to an arrangement according to which BSPs must present a single bid for the provision of both products – i.e. BSPs cannot provide only upward or only downward capacity. In this case, upward and downward balancing capacity is typically bought by the SO at the same price – i.e. BSPs receive the same capacity payment for one MW of balancing capacity provided regardless if it refers to upward capacity or downward capacity. Similarly to what happens to balancing capacity and balancing energy products, upward capacity provision costs and downward capacity provision costs may vary greatly for different BSPs.

#### 2.3.1.2. Market gate-closure

The market gate-closure refers to the time at which bids for a certain product are no longer accepted. If balancing capacity and balancing energy are jointly procured, there is a single gate-closure for products related to a specific balancing service – i.e. the gate-closure for balancing capacity bids; if balancing capacity and balancing energy are procured separately, there are two gate-closures related to a certain balancing service – the **gate-closure for balancing capacity** bids and the **gate-closure for balancing energy** bids.

As previously mentioned, balancing capacity is procured by SOs in order to ensure that operational security is continuously guaranteed. This, together with the fact that most power systems rely, at some extent, on inflexible generation capacity for which operation decisions have to be taken at least several hours ahead of real-time, results in the definition of early gate-closures (in respect to delivery) for balancing capacity bids. Therefore, depending on the characteristics of the power system and on the definition of balancing capacity and balancing energy products, gate-closures for balancing energy vary from one hour before real-time up to one year in advance. **Early gate-closures can undermine competition in balancing markets**, since they prevent or limit the participation of renewable producers and other potential providers in active balancing.

#### 2.3.1.3. **Pricing of balancing products**

The price of balancing products should provide adequate signals for BSPs to efficiently invest in balancing capacity and provide balancing services. Since imbalance prices are directly related to balancing energy prices, the latter also influence BRPs' (efficient) decisions. In general, the settlement of balancing energy provision is based either on **pay-as-bid pricing –** i.e. BSPs are settled according to their price offer – or on pay-as-cleared pricing – i.e. all BSPs are settled according to the market **marginal price**. In this respect, some European countries such as Germany and Belgium combine pay-as-bid pricing for balancing energy with average imbalance prices aiming at providing less volatile prices. Nevertheless, pay-as-bid pricing provides incentives to market parties to submit bids as close as possible to the expected marginal price, which is a disadvantage for small players that do not have the same possibilities to forecast prices. Therefore, it may act as an entry barrier and undermine competition in balancing markets. Notice that pay-as-bid pricing may also lead to an inefficient market clearing due to the strategic behaviour of the agents. On the other hand, marginal prices lead to a more efficient allocation of resources since it reflects (balancing) energy scarcity, providing more efficient signals to market parties.

Another relevant issue related to the pricing of balancing energy is the existence of **price limits –** i.e. imposition of minimum/maximum price levels – which may prevent balancing energy prices from reflecting balancing costs under certain system operation conditions. For instance, **negative prices** reflect system conditions during super off-peak hours when the cost of downward balancing energy provision by thermal power plants operating very close to their minimum output values can be very high. The inexistence of negative energy prices prevents (balancing energy and imbalance) prices from reflecting balancing costs during these situations which may result in distorted incentives to market parties.

### 2.3.2. **Imbalance settlement arrangements**

As previously mentioned, a main condition for effective passive balancing is that imbalance prices are cost-reflective – i.e. they should reflect as much as possible the **real-time value of (balancing) energy**. Arrangements influencing cost-reflectiveness of imbalance prices include: i) the definition of system overall imbalance; ii) the imbalance settlement period; and iii) imbalance pricing. These topics are briefly discussed in the following subsections.

#### 2.3.2.1. Definition of system overall imbalance

The general principle of the imbalance settlement is that all injections and withdrawals must be covered by balancing responsibility (ACER, 2012). In this respect, an imbalance can be defined as the difference between the final position of a certain BRP – i.e. its final generation/consumption schedule – and the volume of energy actually injected/withdrawn by this BRP over the settlement period. The system overall imbalance is determined by the net amount of balancing energy deployed over the settlement period[9]. In principle, the net volume of balancing energy activated within a settlement period should equal the net sum of BRPs imbalances computed for the same period. However, as previously explained, balancing energy can be deployed for purposes other than balancing (e.g. congestion management). If balancing energy activated for purposes other than balancing influences balancing energy prices, imbalance prices may be distorted.

#### 2.3.2.2. The imbalance settlement period

The imbalance settlement period refers to the period of time for which imbalances are calculated and determines the maximum difference between actual and average imbalances (Beune and Nobel, 2001), as shown in Figure 2.5.

[9]It is worth mentioning that the Dutch SO defines the possibility of a “dual” system imbalance state when both upward and downward balancing resources are activated within a single settlement period. This is further discussed in Chapter 3.

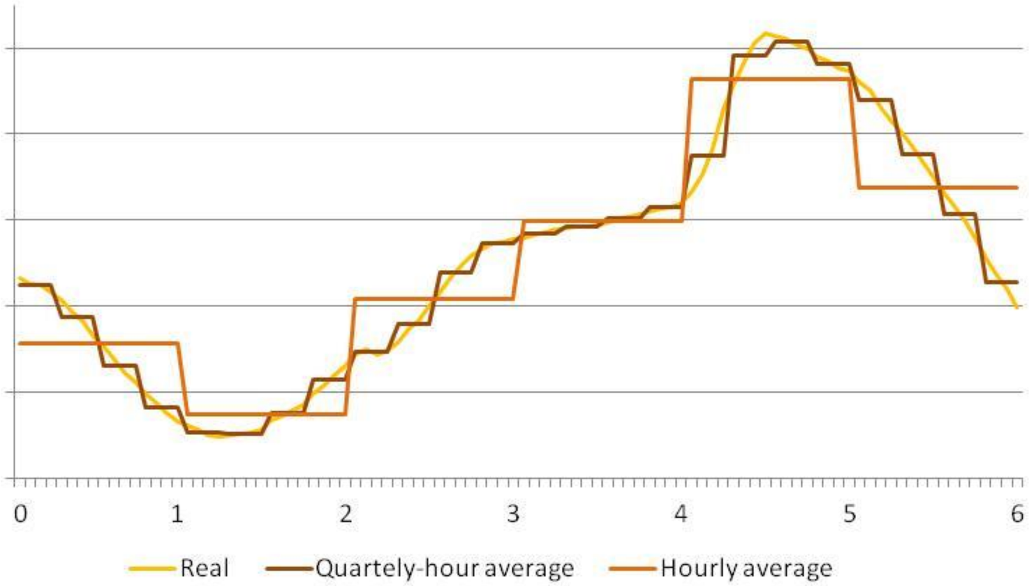



**Figure 2.5: Example of real, quarterly-hour and hourly average absolute imbalances**

As it can be observed in the figure, the longer the settlement period is, the higher is the difference between average and actual imbalances. Since the balance state and, consequently, imbalance prices depend on the net amount of balancing energy deployed within the settlement period, the longer the settlement period is the more imbalance prices will deviate from real-time (balancing) energy costs.

#### 2.3.2.3. Imbalance pricing

Imbalances are settled according to either a single imbalance price system – such as in Belgium, Germany and the Netherlands – or a dual pricing system – such as in Spain and the Nordic countries. Under a **single-price** system, the same imbalance price is applied to BRPs with short and long positions; this price corresponds either to the average or to the marginal price of balancing energy deployed within the settlement period. Under a **dual-price** system, different imbalance prices are applied to BRPs with short and long positions: while BRPs that aggravate the system imbalance are settled at the average or marginal price of deployed balancing energy, BRPs that reduce the system imbalance are typically settled at the day-ahead market price. In general, single pricing provides stronger incentives for passive balancing since BRPs contributing to system balancing are rewarded for passively balancing the system, as explained in Section 2.2.2.

## 2.4. The European Target Model on Electricity

The Target Model aims at eliminating cross-border barriers for the integration of European electricity markets and its implementation is equivalent to the completion of the **Internal Electricity Market** (ENTSO-E, 2014b). The model is the blueprint for regional integration and is currently being implemented bottom-up through **regional market coupling** projects and top-down through the establishment of common regulation by the European Commission based on the **Framework Guidelines**[10] and **Network Codes**[11] developed by the Agency for the Cooperation of Energy Regulators (ACER) and ENTSO-E, respectively.

The Framework Guidelines envisage the harmonization of European market designs, establishing common principles for the development of: (i) a single day-ahead market coupling with implicit auctions of cross-border capacity; (ii) a single intraday market coupling with continuous implicit allocation of cross-border capacity; (iii) a single European platform for allocating long-term transmission capacity rights; (iv) a flow-based capacity allocation method in highly meshed networks; and (v) common merit-order lists for the cross-border exchange of balancing energy from FRR and RR. Based on these guidelines, ENTSO-E developed several network codes to be implemented in all European countries within the near future.

Regarding **electricity balancing**, ACER's framework guidelines establish that SOs shall balance the system pursuing the following **objectives**: (i) to safeguard operational security; (ii) to foster competition in balancing markets; (iii) to facilitate wider participation of renewable generators and demand response in electricity balancing; (iv) to increase social welfare; and (v) to promote cross-border balancing exchanges. As previously explained, this thesis focuses on market arrangements facilitating the **participation of renewable generators in electricity balancing**. Apart from being an objective itself, the participation of renewable agents in electricity balancing contributes to the achievement of other goals of the European Target Model on Electricity Balancing, such as increasing competition and efficiency in balancing mechanisms. In this respect, some of main the guidelines set ACER include:

- Imbalance settlement: the imbalance settlement should be designed in such a way that imbalance prices reflect the real-time price of energy, so that BRPs are

[10] http://www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/default.aspx
[11] https://www.entsoe.eu/major-projects/network-code-development/Pages/default.aspx

incentivized to be in balance during real-time and, if allowed within the terms and conditions related to balancing, to respond adequately to the information close to real-time on the system imbalance and imbalance price.

- Procurement of balancing energy: the price of balancing energy should not be predetermined by a contract for balancing capacity provision. Apart from this, BSPs should be allowed to place and/or update their bids as close to real-time as possible and at least up to one hour before real-time.
- Procurement of balancing capacity: upward and downward balancing capacity should be procured separately and balancing capacity should be contracted as much as possible in the short term in order to facilitate the participation of new entrants, such as renewable generators.

In respect to these guidelines, the following provisions are established in the **Guideline on Electricity Balancing**, approved on the 16th of March of 2017 by Member States and expected to be published as Regulation by the European Commission by the end of 2017[12]:

i) Imbalance settlement:
   a. In three years after the entry into force of the Guideline, the imbalance settlement period should be 15 minutes. Regarding this requirement, a joint request of exemption made by the SOs of a synchronous area is allowed. It is worth mentioning that in its package of measures published on the 3oth of November of 2016, the European Commission proposes the year of 2025 as a deadline for the adoption of the 15-minute imbalance settlement period.
   b. Imbalance prices can be set according to either a single or a dual pricing system.
   c. Information regarding the activation of balancing resources shall not be published later than 30 minutes after real-time.

ii) Balancing energy:
   a. The price of balancing energy bids shall not be predetermined in a contract for balancing capacity.
   b. The gate-closure for balancing energy products shall not be before the gate-closure of the intraday cross-zonal gate closure time, which is established by

[12] https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/Pages/default.aspx

the Guideline on Capacity Allocation and Congestion Management at one hour before real-time.

iii) Balancing capacity:

a. Upward and downward products should, in principle, be procured separately. Nevertheless, a SO may combine the procurement the procurement of upward and downward capacity bids if it demonstrates that this arrangement would lead to higher economic efficiency.

Despite these provisions, it is not clear how the future European Balancing Market will look like. After the entry into force of the Regulation on Electricity Balancing, based on the principles set in it, European SOs will have to work on the definition of harmonized market arrangements. In this respect, it is worth pointing out that although the Regulation on Capacity Allocation and Congestion Management establishes that the European Intraday Market will be based on continuous trading (European Commission, 2015), the final design is current under discussion among SOs and market operators (ENTSO-E, 2016).

In this context, this thesis aims at enlightening the discussion on the design of the future European Balancing Market taking into account the integration of increasing amounts of intermittent renewable generation. For this purpose, Chapter 3 analyzes imbalance settlement designs and provides recommendations on arrangements leading to cost-reflective imbalance prices. Chapter 4 discusses the design of markets for the procurement of balancing products and proposes recommendations for the improvement of competition and efficiency in those markets. Finally, due to the importance of intraday markets to electricity balancing and to the integration of renewable generation, Chapter 5 contributes to the current discussion on the design of the European Intraday Market.

## 2.5. Conclusions

The secure operation of power systems depends on the continuous balance between generation and demand. SOs can balance the system by activating BSPs (active balancing) and by sending efficient market signals for BRPs to support the system balance (passive balancing). Arrangements related to active balancing were developed in a context in which power systems were dominated by conventional power plants – traditional suppliers of balancing services.

Furthermore, arrangements related to passive balancing were designed aiming at BRPs' self-balancing.

The increasing penetration of renewable generation may impose relevant challenges to electricity balancing since it affects both active balancing (by displacing the traditional balancing resources from the daily electricity dispatch) and passive balancing (for renewable generators, self-balancing can be more costly than incurring imbalance costs). In this context, balancing arrangements need to be adapted in order to facilitate the participation of renewable generators in active and passive balancing.

This chapter defines electricity balancing and provides a critical of current European balancing arrangements, pointing out those that may limit or facilitate the participation of renewable generators in balancing mechanisms and serves as a basis for the analyses carried out in Chapter 3, 4 and 5.

# Chapter 3: Arrangements for effective passive balancing

It was argued on Chapter 2 that passive balancing facilitates the participation of renewable in electricity balancing which in turn contributes the optimization of the procurement of balancing products. However, incentives for market players to effectively contribute to passive balancing depend on the existence of cost-reflective imbalance prices. Therefore, the aim of this chapter is to identify adequate imbalance settlement arrangements that lead to the calculation of cost-reflective imbalance prices. Due to the existence of similar arrangements in other European countries and the availability of plenty of public data, empirical analyses using data from the Spanish market are carried out to support the discussion. The Spanish case is a very interesting example since the country has experienced significant penetration of renewable generation. Moreover, it has recently modified its regulatory framework in order to allow the participation of renewable producers in balancing markets. Chapter 3 is divided into three main sections:

I. First, cost-reflective imbalance settlement arrangements are discussed from a theoretical point of view. Numerical examples are used to support the discussion.
II. After that, the Spanish imbalance settlement design is described.
III. Finally, analyses using real data from the Spanish market are carried out in order to identify distortions associated to the presence of inadequate arrangements and to propose recommendations for design options leading to cost-reflective imbalance prices.

## 3.1. Cost-reflective imbalance settlement arrangements

As explained in Section 2.3.1.3, **marginal prices provide efficient signals** to market agents since they reflect market scarcity. Therefore, higher efficiency is achieved in balancing markets when prices of balancing products and imbalances are based on marginal pricing. Furthermore, in order to provide efficient market signals to BRPs, imbalance prices must be **cost-reflective**, i.e. they must correctly pass on (real-time) balancing costs to responsible market parties. Notice that, regardless the agents capacity payments should be allocated to, they should not be passed on through imbalance prices since balancing capacity cannot be directly related to actual (real-time) imbalances, as discussed in Section 2.2[13].

When **imbalance prices are cost-reflective** *payments and revenues resulting from the settlement of balancing energy between the SO and BSPs and payments and revenues resulting from the settlement imbalances between the SO and BRPs are balanced.*

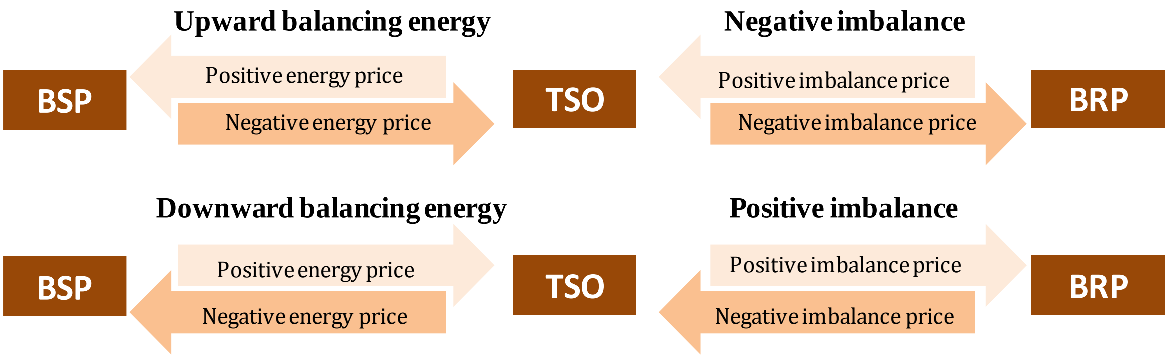



**Figure 3.1: Settlement of balancing energy and imbalances – payment flows**

Figure 3.1 represents payment flows between BRPs and the SO and between the SO and BSPs. The following subsections discuss imbalance settlement arrangements leading to cost-reflective imbalance prices.

### 3.1.1. Imbalance pricing

As explained in Section 2.3.2.3, there are two main systems for settling imbalances: **single**

[13]In this respect, ACER recommends that the imbalance price must not be used to recover costs other than balancing energy costs, although it recognizes the right of SOs to establish separate settlement mechanisms to allocate balancing capacity costs to imbalanced BRPs (ACER, 2015).

**pricing** and **dual pricing**. Table 3.1 shows typical imbalance prices applied to imbalanced BRPs under single and dual pricing systems. $P_{dw}$ and $P_{up}$ correspond to the prices of downward and upward balancing energy activated within a settlement period, respectively; and $P_{DA}$ refers to the day-ahead market price corresponding to the same settlement period. Positive and negative values indicate the sign of imbalances: if imbalance prices are positive, long BRPs receive the imbalance price and short BRPs pay the imbalance price; if imbalance prices are negative, long BRPs pay the imbalance price and short BRPs receive the imbalance price (see Figure 3.1).

**Table 3.1: Imbalance prices under single and dual pricing systems**

| | | System imbalance | |
|---|---|---|---|
| | | Long (positive) | Short (negative) |
| Single-price system | Long BRPs | $+ P_{dw}$ | $+ P_{up}$ |
| | Short BRPs | $- P_{dw}$ | $- P_{up}$ |
| Dual-price system | Long BRPs | $+ P_{dw}$ | $+ P_{DA}$ |
| | Short BRPs | $- P_{DA}$ | $- P_{up}$ |

It can be observed in Table 3.1 that, regardless the pricing system, the imbalance price applied to BRPs that aggravate the system imbalance is based on the price of balancing energy activated to manage the system imbalance: when the system is short, the imbalance price applied to shot BRPs is based on the price of upward balancing energy used; when the system is long, the imbalance price applied to long BRPs is based on the price of downward balancing energy.

The **main difference** between single and dual pricing systems is related to the imbalance price applied to BRPs that reduce the system imbalance: under single pricing, BRPs that deviate in the opposite direction of the system balance are settled as BSPs. In this case, when the system is long, short BRPs are treated as BSPs providing downward balancing energy and are settled according to the downward balancing energy price; when the system is short, long BRPs are treated as BSPs providing upward balancing energy and are settled according to the upward balancing energy price. On the other hand, under dual pricing, BRPs are treated as if they had perfectly forecasted their production/consumption in the day-ahead timeframe. In this case, when the system is long, short BRPs are settled at the day-ahead market price and, when the system is short, long BRPs are settled at the day-ahead market price.

In order to illustrate the difference between single and dual imbalance pricing, an example (**Example 1**) is provided in Table 3.2 and Table 3.3. The following assumptions are considered:

- The system has three BRPs: $BRP_1$ has an absolute imbalance of 30 MWh aggravating the system imbalance; $BRP_2$ has an absolute imbalance of 20 MWh reducing the system imbalance; $BRP_3$ is balanced and is also a BSP providing 10 MWh of downward or upward balancing energy (depending on the system imbalance) to keep the system balanced. Here, it is important to emphasize that all BSPs are BRPs since all market participants are subjected to balancing responsibility[14], but not all BRPs are BSPs (in order to be a BSP and provide balancing services market participants must pass technical qualifications tests).
- Two settlement periods (SP) are analyzed: over $SP_1$, the system is long and $BRP_1$ is long, $BRP_2$ is short, and $BRP_3$ provides downward balancing energy; over SP2, the system is short and $BRP_1$ is short, $BRP_2$ is long, and $BRP_3$ provides upward balancing energy.
- For simplification purposes, intraday trading is not considered.
- The following prices are considered: $P_{DA}$ = 55 €/MWh; $P_{up}$ = 60 €/MWh; $P_{dw}$ = 40 €/MWh.
- It is considered that $P_{up}$ and $P_{dw}$ correspond to the marginal prices of upward and downward balancing energy, respectively, and the imbalance price is set by the marginal price of balancing energy activated to balance the system.

Table 3.2 presents the settlement of imbalances of $BRP_1$ and $BRP_2$ according to single and dual pricing systems the settlement of balancing energy provided by $BRP_3$, and the net income resulting from the settlement of imbalances and balancing energy. A **positive settlement** refers to a revenue right that must be paid by the SO to the BRP and a **negative settlement** refers to a payment obligation imposed on the BRP by the SO. Finally, a positive **net income** implies a transfer of money from market participants to the SO while a negative net income implies a transfer of money from the SO to market participants.

[14] There might be exemptions from balancing responsibility. For instance small renewable generators in some countries do not bear balancing costs.

If marginal pricing is applied and arrangements related to the settlement period and imbalance calculation are properly defined, single pricing would result in a null net income for the SO, **dual pricing would imply a transfer of money** from market participants to the SO. This "extra" revenue is typically used to reduce electricity tariffs, which, in practice, means a transfer of income from smaller BRPs/BRPs subjected to higher imbalances – such as wind and other intermittent renewable generators – to average users since the latter can benefit from larger balancing portfolios (Chaves-Ávila et al., 2014; Hiroux and Saguan, 2010; Vandezande et al., 2010).

**Table 3.2: Example 1 – Settlement of imbalances and balancing energy under single and dual pricing systems**

| | $SP_1$: system is long | | $SP_2$: system is short | |
|---|---|---|---|---|
| | Single-price | Dual-price | Single-price | Dual-price |
| $BRP_1$ | $30\times40 = 1{,}200$ | $30\times40 = 1{,}200$ | $-30\times60 = -1{,}800$ | $-30\times60 = -1{,}800$ |
| $BRP_2$ | $-20\times40 = -800$ | $-20\times55 = -1{,}100$ | $20\times60 = 1{,}200$ | $20\times55 = 1{,}100$ |
| $BRP_3$ | $-10\times40 = -400$ | $-10\times40 = -400$ | $10\times60 = 600$ | $10\times60 = 600$ |
| Net income | **0** | **300** | **0** | **100** |

Table 3.3 shows the net positions of $BRP_1$ and $BRP_2$ compared to the case in which they do not deviate from their market schedules and the net position of $BRP_3$ in comparison to the case in which it does not provide balancing energy. It can be observed that, under both imbalance pricing schemes, the BRP which aggravates the system imbalance (represented by $BRP_1$) is financially penalized for its imbalance, while the BRP which provides balancing energy to the system (represented by $BRP_3$) is rewarded the difference between the price of selling balancing energy and the day-ahead market price. On the other hand, the situation of the BRP which contributes to reduce the system imbalance (represented by $BRP_2$) changes according to the imbalance price design: under single imbalance pricing, the BRP is rewarded the difference between the price of balancing energy and the day-ahead market price, while under dual imbalance pricing, its net position does not change in respect to the situation in which the BRP does not deviate from its day-ahead market schedule[15].

[15]Notice that, in the example, intraday trade is not considered. In case BRPs that contribute to reduce the system imbalance trade in the intraday market, their situation under a dual pricing system will depend on the difference between the day-ahead and intraday market prices.

**Table 3.3: Example 1 – Financial position of BRPs participating in balancing mechanisms in respect to day-ahead market price**

| | $SP_1$: system is long | | $SP_2$: system is short | |
|---|---|---|---|---|
| | Single-price | Dual-price | Single-price | Dual-price |
| $BRP_1$ | $30\times(40-55)$ $=-450$ | $30\times(40-55)$ $=-450$ | $-30\times(60-55)$ $=-150$ | $-30\times(60-55)$ $=-150$ |
| $BRP_2$ | $-20\times(40-55)$ $=300$ | $-20\times(55-55)=0$ | $20\times(60-55)=100$ | $20\times(55-55)=0$ |
| $BRP_3$ | $-10\times(40-55)$ $=150$ | $-10\times(40-55)$ $=150$ | $10\times(60-55)=50$ | $10\times(60-55)=50$ |

Notice that **single imbalance pricing** provides stronger incentives for **passive balancing** since both types of BRPs (i.e. short and long) perceive the efficient signal provided by the (marginal) price of balancing energy, which reflects the system state (and the costs incurred by the SO) in real-time. In this case, when BRPs support the system balance, they are financially compensated.

On the other hand, **dual imbalance pricing** provides incentives for **self-balancing** (i.e. BRPs trying to avoid being penalized) only, which can be very costly for renewable producers and, in this case, ineffective. Furthermore, in cases in which renewable producers could contribute to reduce the system imbalance instead of pursuing self-balancing, they do not have economic incentives to do so. A clear example of this is a situation in which the system is long due to very high renewable production. In such cases, downward balancing prices (and the corresponding imbalance price) could fall below zero (for instance when online thermal generation becomes very inflexible). In this case and according to Table 3.2, if single imbalance price is applied, renewable producers would have an incentive to reduce their production and receive the imbalance price for short BRPs[16]. On the other hand, if a dual system is applied, short BRPs would have to pay the imbalance price, which, in this case, is not based on the price of balancing energy.

Apart from providing stronger incentives for passive balancing, **single imbalance pricing confers a level playing field** for small BRPs since it eliminates the effect of imbalance netting within large BRPs. In order to illustrate this, **Example 2**, shown in Table 3.4 and Table 3.5,

[16] As previously discussed, when the imbalance price is negative short BRPs receive the imbalance price and long BRPs pay the imbalance price.

compares the imbalance costs faced by a single unit when it is integrated into a large BRP and the costs incurred by this same unit when it is not integrated into a large BRP. For comparison purposes, imbalance costs are calculated according to single and dual pricing systems.

**Table 3.4: Example 2 – Imbalance netting within a large BRP**

| | $BRP_1$ | | | $BRP_2$ | | System imbalance | $P_{DA}$ | $P_{dev}$ |
|---|---|---|---|---|---|---|---|---|
| | Unit 1 | Unit 2 | Total $BRP_1$ | Unit 3 | Total $BRP_2$ | | | |
| SP1 | 2 | 10 | 12 | 2 | 2 | 14 | 40 | 35 |
| SP2 | 20 | 5 | 25 | 20 | 20 | 45 | 49 | 29 |
| SP3 | -26 | 17 | -9 | -26 | -26 | -35 | 31 | 52 |
| SP4 | -19 | 21 | 2 | -19 | -19 | -17 | 45 | 48 |
| SP5 | 27 | 20 | 47 | 27 | 27 | 74 | 36 | 22 |

Table 3.4 presents the imbalances of $BRP_1$ and $BRP_2$, the imbalance price applied to BRPs aggravating the system imbalance ($P_{dev}$) and the day-ahead market price ($P_{DA}$) over five settlement periods. $BRP_1$ represents a large BRP composed of units 1 and 2 and $BRP_2$ represents a small BRP composed of unit 3. For the purpose of this example, it is considered that Unit 1 ($BRP_1$) and Unit 3 ($BRP_2$) face the same imbalances and that these deviations aggravate the system imbalance in all of the settlement periods of the example.

Table 3.5 compares the settlement of the large BRP ($BRP_1$) and the individual settlements of its units according to single and dual pricing systems. It can be observed in Table 3.5 that, under a dual pricing system, overall imbalance costs of $BRP_1$ amount to 1,407 €. However, individual imbalance costs of units 1 and 2 add up to 1,821 €. In this case, imbalance netting within $BRP_1$ decreases the overall imbalance costs allocated to this BRP, reducing also imbalance costs faced by units within the BRP[17].

On the other hand, under single pricing, overall imbalance costs of $BRP_1$ amount to 1,401 €, which the exact sum of imbalance costs allocated to Unit 1 (1,391 €) and Unit 2 (10 €). In this case, each unit faces its actual imbalance costs, providing stronger incentives for passive balancing. It is also important to notice that overall imbalance costs under single imbalance price

[17]For instance, a way of allocating imbalance costs among units within a BRP is by distributing these costs according to their absolute imbalances.

are lower than those faced by BRPs under a dual pricing system. As previously explained, under single pricing, when a BRP contributes to reduce the system imbalance it is financially compensated as if it was a BSP.

**Table 3.5: Example 2 – Settlement of large BRPs under single and dual imbalance pricing**

| | BRP1 | | Unit 1 | | Unit 2 | |
|---|---|---|---|---|---|---|
| | Single-price | Dual-price | Single-price | Dual-price | Single-price | Dual-price |
| SP1 | $12\times(35-40) = -60$ | $12\times(35-40) = -60$ | $2\times(35-40) = -10$ | $2\times(35-40) = -10$ | $10\times(35-40) = -50$ | $10\times(35-40) = -50$ |
| SP2 | $25\times(29-49) = -500$ | $25\times(29-49) = -500$ | $20\times(29-49) = -400$ | $20\times(29-49) = -400$ | $50\times(29-49) = -100$ | $50\times(29-49) = -100$ |
| SP3 | $-9 \times(52-31) = -189$ | $-9 \times(52-31) = -189$ | $-26 \times(52-31) = -546$ | $-26 \times(52-31) = -546$ | $17\times(52-31) = 357$ | $17\times(31-31) = 0$ |
| SP4 | $2\times(48-45) = 6$ | $2\times(45-45) = 0$ | $-19 \times(48-45) = -57$ | $-19 \times(48-45) = -57$ | $21\times(48-45) = 63$ | $21\times(45-45) = 0$ |
| SP5 | $47\times(22-36) = -658$ | $47\times(22-36) = -658$ | $27\times(22-36) = -378$ | $27\times(22-36) = -378$ | $20\times(22-36) = -280$ | $20\times(22-36) = -280$ |
| Total | $\mathbf{-1,401}$ | $\mathbf{-1,407}$ | $\mathbf{-1,391}$ | $\mathbf{-1,391}$ | $\mathbf{-10}$ | $\mathbf{-430}$ |

In conclusion, **single imbalance pricing** presents at least two import advantages compared to dual pricing systems: first, it gives a **fairer treatment for small BRPs** since it avoids transfers of money from these market participants to larger BRPs and prevents the latter from benefiting from imbalance netting; second, it provides **efficient market signals** to all BRPs.

It is important to point out though that in the absence of adequate arrangements related to the settlement period and the computation of the system overall imbalance, imbalance prices, in particular when a single system is used, may provide distorted market signals to BRPs and incentivize the latter to worsen the system imbalance. This will be discussed in the following subsections.

### 3.1.2. **Settlement period**

As mentioned in Section 2.3.2.2, **long settlement periods** can limit in a significant way the cost-reflective allocation of real-time balancing costs to imbalanced BRPs since BRPs that are balanced over a long settlement period may have been out of balance several times within the settlement period. Furthermore, it is more likely that balancing energy bids in opposite directions (i.e. upwards and downwards) are activated within long settlement periods. Both situations hinder effective allocation of imbalance costs.

**Table 3.6: Example 3 – Imbalances within 15-minute periods (MWh)**

| | **BRP1** | | | **BRP2** | | | **System imbalance** | **Ebal** |
|---|---|---|---|---|---|---|---|---|
| | Schedule | Production | Imbalance | Schedule | Production | Imbalance | | |
| 00:00 - 00:15 | 25 | 40 | 15 | 35 | 30 | −5 | 10 | −10 |
| 00:15 - 00:30 | 25 | 35 | 10 | 35 | 20 | −15 | −5 | 5 |
| 00:30 - 00:45 | 25 | 20 | −5 | 35 | 30 | −5 | −10 | 10 |
| 00:45 - 01:00 | 25 | 5 | −20 | 35 | 40 | 5 | −15 | 15 |

In order to illustrate this, a case example of a system with two BRPs (**Example 3**) is provided in Table 3.6, where "Schedule" refers to the BRP market schedule; "Production" refers to the actual/measured production of the corresponding BRP; "Imbalance" refers to the difference between the BRP actual production and its market schedule over 15-minute intervals; and $Ebal$ corresponds to the net balancing energy activated to balance the system within the 15-minute intervals. Negative values of $Ebal$ indicates the activation of downward balancing to compensate a net positive imbalance while positive values indicates the activation of upward balancing to compensate a net negative imbalance.

The settlement of deployed balancing energy and imbalances presented in Example 3 is analyzed under three case-scenarios: in case A, the settlement period is 15 minutes; in case B, the settlement period is 30 minutes; in case C the settlement period is one hour. For the sake of simplicity, the following assumptions are taken into account:

- Imbalances are settled according to a single pricing system and the imbalance price ($P_{dev}$) is equal to the marginal price of (net) balancing energy ($P_{Ebal}$) activated within the settlement period.

- Table 3.7 presents balancing energy bid curves considered in Example 3. In this respect, it is worth emphasizing that the price of downward balancing energy is the price at which the SO sells balancing energy to the BSP; therefore, the SO will accept first the downward balancing energy bids with the highest prices. It is also important to point out that BSPs may face different costs when providing balancing services (further discussed in Chapter 4). In this example, $BSP_1$ presents the cheapest offer for upward balancing energy and the most expensive offer for downward balancing energy.

**Table 3.7: Example 3 – Balancing energy bid curves**

| | Upward $Ebal$ (MWh) | $P^{up}$(€/MWh) | | Downward $Ebal$ (MWh) | $P^{dw}$ (€/MWh) |
|---|---|---|---|---|---|
| $BSP_1$ | 5 | **58** | $BSP_3$ | 5 | **42** |
| $BSP_2$ | 5 | **60** | $BSP_2$ | 5 | **40** |
| $BSP_3$ | 5 | **62** | $BSP_4$ | 5 | **38** |
| $BSP_4$ | 5 | **65** | $BSP_1$ | 5 | **35** |

A. <u>15-minute settlement period</u>

Table 3.8 shows the settlement of imbalances and balancing energy considering a settlement period of 15 minutes. Over **settlement period 1**, the system imbalance is 10 MWh long (sum of the imbalances of $BRP_1$ and $BRP_2$). To compensate this imbalance, the SO activates 5 MWh of downward balancing energy from $BSP_3$ and 5 MWh of balancing energy from $BSP_2$. Therefore, the marginal price of downward balancing energy, which determines the imbalance price, is 40 €/MWh. This means that all BSPs providing downward balancing energy and all BRPs are settled at 40 €/MWh.

Over **settlement period 2**, the system imbalance is 5 MWh short, which is compensated by the activation of 5 MWh of upward balancing energy from $BSP_1$. In this case, the marginal price of upward balancing energy and, consequently, the imbalance price, is 58 €/MWh.

Over **settlement period 3**, the system is 10 MWh short and the imbalance price is the marginal of upward balancing energy price corresponding to the activation of $BSP_1$ and $BSP_2$, which is equal to 60 €/MWh.

Finally, over **settlement period 4** the system is 15 MWh short and the imbalance price is the marginal price of upward balancing energy corresponding to the activation of $BSP_1$, $BSP_2$ and $BSP_3$, which is equal to 62 €/MWh.

**Table 3.8: Example 3 – Settlement of imbalances and balancing energy for 15-minute settlement periods**

| SP | | Settlement of $BSP_1$ | Settlement of $BSP_2$ | Settlement of $BSP_3$ | Settlement of $BRP_1$ | Settlement of $BRP_2$ | Net income |
|---|---|---|---|---|---|---|---|
| 1 | 00:00-00:15 | - | $-5\times40 = -200$ | $-5\times40 = -200$ | $15\times40 = 600$ | $-5\times40 = -200$ | 0 |
| 2 | 00:15-00:30 | $5\times58 = 290$ | - | - | $10\times58 = 580$ | $-15\times58 = -870$ | 0 |
| 3 | 00:30-00:45 | $5\times60 = 300$ | $5\times60 = 300$ | - | $-5\times60 = -300$ | $-5\times60 = -300$ | 0 |
| 4 | 00:45-01:00 | $5\times62 = 310$ | $5\times62 = 310$ | $5\times62 = 310$ | $-20\times62 = -1{,}240$ | $5\times62 = 310$ | 0 |
| **Total** | **00:00-01:00** | **900** | **410** | **110** | **−360** | **−1,060** | **0** |

Over **the whole hour** (00:00-01:00), the SO incurs in net balancing costs of 1,420 € related to the activation of balancing energy: 900 € paid to $BSP_1$, 410 € paid to $BSP_2$, and 110 € paid to $BSP_3$. These costs are allocated to $BRP_1$ and to $BRP_1$ according to their 15-minute imbalances. In this case, and considering that within each 15-minute interval balancing energy is activated in a single direction (i.e. upwards or downwards), payments and revenues resulting from the settlement of imbalances and balancing energy are balanced over each settlement period.

B. 30-minute settlement period

When the settlement period is increased to 30 minutes, the system imbalance state (i.e. long or short) over a settlement period is given by the net balancing energy activated within two consecutive 15-minute periods. BRPs' imbalances are also determined by their net imbalance over 30-minute intervals. Table 3.9 shows the settlement of imbalances and balancing energy considering 30-minute settlement periods.

Over **settlement period 1**, $BRP_1$ is 25 MWh long and $BRP_2$ is 20 MWh short; consequently, the system is 5 MWh long. Within this period, the SO activated 5 MWh of downward balancing energy from $BSP_2$, 5 MWh of downward balancing energy from $BSP_3$, and

5 MWh of upward balancing energy from $BSP_1$. As previously explained, the imbalance price is determined by the price of the net balancing energy activated to compensate the system imbalance. In this case, the imbalance price is the (marginal) price of downward balancing energy, which is 40 €/MWh (price set by the marginal BSP, i.e. $BSP_2$). Therefore, downward balancing energy and imbalances over period 1 are settled at 40 €/MWh. On the other hand, upward balancing energy provided by $BSP_1$ is settled at 58 €/MWh (marginal price of activated upward balancing energy).

It is important to highlight that the rationale used in Case B is the same as the one applied in Case A. The differences between the two cases refer to the allocation of costs and revenues and to the net income resulting from the settlement of balancing energy and imbalances.

**Table 3.9: Example 3 - Settlement of imbalances and balancing energy for 30-minute settlement periods**

| SP | | Settlement of $BSP_1$ | Settlement of $BSP_2$ | Settlement of $BSP_3$ | Settlement of $BRP_1$ | Settlement of $BRP_2$ | Net income |
|---|---|---|---|---|---|---|---|
| 1 | 00:00-00:30 | $5\times58=290$ | $-5\times40=-200$ | $-5\times40=-200$ | $25\times40=1{,}000$ | $-20\times40=-800$ | $-90$ |
| 2 | 00:30-01:00 | $10\times62=620$ | $10\times62=620$ | $5\times62=310$ | $-25\times62=-1{,}550$ | $0\times62=0$ | $0$ |
| **Total** | **00:00-01:00** | **910** | **420** | **110** | **−550** | **−800** | **−90** |

It can be observed in Table 3.9 that the settlement of BSPs over the whole **period 00:00-00:30** does not change in Case B with respect to Case A. On the other hand, revenue rights and payment obligations allocated to $BRP_1$ and $BRP_2$ over the same period are reduced in Case B in comparison to Case A. Regarding the settlement of $BRP_1$, this can be explained by the fact that in case A this BRP contributes to reduce the system imbalance over the period 00:15-00:30 and it is settled accordingly. In Case B, $BRP_1$ is penalized for aggravating the system imbalance over the whole the settlement period (i.e. 00:00-00:30). Consequently, its revenue rights are reduced in Case B.

As for $BRP_2$, while in Case A it aggravates the system imbalance over the period 00:15-00:30 and it is penalized accordingly, in Case B it contributes to reduce the system imbalance over the whole period 00:00-00:30. Therefore, its payment obligations are reduced from Case A to Case B.

Finally, over period 1, the settlement of balance energy and imbalances results in a negative **net income** of 90 €, which is explained by the fact that the imbalance price, which is determined by the net amount of balancing energy deployed over the whole settlement period does not reflect the (upward) balancing costs incurred during the period 00:15-00:30. In this respect, it is worth mentioning that part of these costs could be recovered if dual imbalance pricing is implemented. This is explained by the "extra" revenue resulting from the transfer of money from BRPs contributing to reduce the system imbalance to the SO (explained in Section 3.1.1). Nevertheless, as previously discussed, dual imbalance pricing imposes higher penalizations on smaller agents and limits incentives for passive balancing.

Over the **period 00:30-01:00**, total balancing costs incurred by the SO increase in Case B with respect Case A. This is due to the fact that in Case B the marginal price of upward balancing energy over the period is set at 62 €/MWh (marginal price for the whole 30-minute settlement period) while in case A the marginal price of upward balancing energy over the period 00:30-00:45 is set at 60 €/MWh. The **allocation of balancing costs** to $BRP_1$ and $BRP_2$ also changes in comparison to Case A: despite $BRP_2$ being out of balance during the last two 15-minute intervals, over the period 00:30-01:00 this BRP is balanced and, consequently, does not face balancing costs in Case B. These costs are fully allocated to $BRP_1$ instead.

C. <u>Hourly settlement period</u>

Table 3.10 presents the settlement of imbalances and balancing energy considering an hourly settlement period. As it can be observed in the table, the settlement of all market participants is modified with respect to Case A.

**Table 3.10: Example 3 - Settlement of imbalances and balancing energy an hourly settlement period**

| SP | | Settlement of $BSP_1$ | Settlement of $BSP_2$ | Settlement of $BSP_3$ | Settlement of $BRP_1$ | Settlement of $BRP_2$ | Net income |
|---|---|---|---|---|---|---|---|
| 1 | 00:00-01:00 | $15\times62 = 930$ | $5\times62 = 310$ | - | - | $-20\times62 = -1{,}240$ | 0 |
| **Total** | **00:00-01:00** | **930** | **310** | **-** | **-** | $\mathbf{-1{,}240}$ | **0** |

First, the **settlement of BSPs** is affected by the change in balancing energy marginal prices. For instance, the 15 MWh of upward balancing energy provided by $BSP_1$ is settled in Case C at

62 €/MWh, which is the marginal price of upward balancing energy over the hourly settlement period, while in Case A it is settled at an weighted average price of 60 €/MWh. The settlement of BSPs is also affected by the calculation of net volumes of balancing energy provided by each BSP: for instance, during the period 00:00-01:00, $BSP_3$ provides 5 MWh of downward balancing energy and 5 MWh of upward energy; however, over the whole hour, the net position of this BSP is not modified. Consequently, the BSP is not entitled to any revenue right or payment obligation. A similar situation is observed in the case of $BSP_2$: during the studied period the BSP provides 5 MWh of downward energy and 10 MWh of upward energy; therefore, over the hourly settlement period it provides 5 MWh of (net) upward balancing energy).

Furthermore, over the hourly settlement period, $BRP_1$ is balanced; consequently no balancing costs are attributed to this BRP but they are all allocated to $BRP_2$ instead. In summary, although total balancing costs in Case C (1,240 €) do not change with respect to Case A, the **distribution of revenue rights and payment obligations** among market participants is modified.

Based on these results, it can be concluded that **long settlement periods** leads to a **poor allocation of balancing costs** to imbalanced BRPs, apart from, in some cases, increasing these costs, as observed in Case B. Furthermore, the use of long settlement periods may result in **distorted imbalance prices**. For instance, while in Case A the imbalance price for the first 15-minute intervals reflects the need for downward and upward balancing energy, respectively, in Cases B and C, it reflects only the need for downward energy in the first case and for upward energy in the latter. Consequently, the shorter the imbalance settlement period is the better imbalance prices will reflect real-time balancing costs.

### 3.1.3. **System imbalance calculation**

The general principle of the imbalance settlement is that **all injections and withdrawals must be covered by balancing responsibility** (ACER, 2012). In this sense, an imbalance can be defined as the difference between the final generation/consumption schedule of a certain BRP and the volume of energy actually produced/consumed by this BRP over a settlement period (ENTSO-E, 2014a).

As shown in Table 3.1, imbalance prices depend on the system imbalance direction (i.e. long or short), which in turn is determined by the net volume balancing energy activated within the settlement period. If balancing energy is activated only to compensate imbalances covered by

BRPs, the system imbalance will be equal to net sum of BRPs' imbalances for each settlement period. In this case, imbalance prices would reflect the costs incurred by the SO to balance the system in real-time. On the other hand, if balancing energy is activated for purposes other than balancing and/or to compensate imbalances not caused by BRPs imbalance prices will most likely be distorted.

In this respect, several SOs (for instance, the Portuguese, the Spanish and the French ones, among others) activate balancing energy bids for managing network constraints. If these bids are taken into account in the imbalance settlement – i.e. if balancing energy prices are affected by the activation of balancing bids for congestion management purposes – imbalance prices are distorted. Another type congestion management interference with imbalance prices is the activation of out-of-merit balancing energy bids due to the presence of network congestions, which may excessively penalize BRPs, as discussed by Vandezande (2011). In this respect, the current version of the Network Code on Electricity Balancing (ENTSO-E, 2014a) establishes that balancing energy bids activated for purposes other than balancing shall not determine the imbalance price.

Grid constraints may also **interfere with imbalance prices** when actions taken by the SO to manage network congestions generate imbalances. For instance, in Spain, the day-ahead congestion management procedure consists of two steps: in the first step, the SO redispatches generation/consumption units to manage grid constraints considering operational security criteria; in the second step, the SO redispatches units in order to reestablish the balance between generation and demand whenever the redispatch performed in the first step produces an imbalance. Nevertheless, if grid constraints are identified in real-time, only the first step is carried out; any imbalance produced by real-time generation redispatch is dealt with as any other generation-demand imbalance, i.e. with the activation of balancing energy. This type of imbalance is neither caused nor should be covered by BRPs (in this sense, imbalances caused and/or covered by BRPs refer, in this thesis, to imbalances resulting from BRPs' consumption/production deviations in respect to their market schedules). However, it affects activation volumes and prices of balancing energy and, consequently, alters imbalance prices.

Table 3.11 provides an example (**Example 4**) of imbalances of a system with two BRPs ($BRP_1$ and $BRP_2$). It is assumed that, for some settlement periods, imbalances not caused/covered by BRPs are produced. It can be observed in the table that imbalances of $BRP_1$ and $BRP_2$ are the same in settlement periods 1, 3, 5 and 7 and in settlement periods 2, 4, 6 and 8.

Over settlement periods 1 and 2 the amount of activated balancing energy is not affected by imbalances not covered by BRPs; over settlement periods 3 and 4, imbalances not covered by BRPs reduce the need of downward and upward balancing energy, respectively; over settlement periods 5 and 6, imbalances not covered by BRPs increase the need of downward and upward balancing energy, respectively; finally, over settlement periods 7 and 8, imbalances not covered by BRPs not only modify the amount of activated balancing energy but they also change the system imbalance direction.

**Table 3.11: Example 4 - Interference of imbalances not covered by BRPs with the system overall imbalance**

| | Imbalance BRP1 | Imbalance BRP2 | Imbalance not covered by BRPs | $Ebal$ |
|---|---|---|---|---|
| 1 | $40$ | $-20$ | $0$ | $\mathbf{-20}$ |
| 2 | $-40$ | $20$ | $0$ | $\mathbf{20}$ |
| 3 | $40$ | $-20$ | $-10$ | $\mathbf{-10}$ |
| 4 | $-40$ | $20$ | $10$ | $\mathbf{10}$ |
| 5 | $40$ | $-20$ | $10$ | $\mathbf{-30}$ |
| 6 | $-40$ | $20$ | $-10$ | $\mathbf{30}$ |
| 7 | $40$ | $-20$ | $-30$ | $\mathbf{10}$ |
| 8 | $-40$ | $20$ | $-30$ | $\mathbf{-10}$ |

**Imbalance prices** corresponding to settlement periods 3, 4, 5 and 6 may be **distorted** if less expensive (cases 3 and 4) or more expensive (cases 5 and 6) balancing energy bids are activated due to imbalances not covered by BRPs. Imbalance prices corresponding to periods 7 and 8 will always be distorted since the direction of the system imbalance is changed.

Table 3.12 presents typical bid curves for upward and downward balancing energy, which are used in Example 4 to calculate imbalance prices corresponding to the imbalances presented in Table 3.11. It is assumed that single imbalance pricing is applied and the imbalance price corresponds to the marginal price of activated balancing energy.

Table 3.13 presents imbalance prices ($P_{dev}$) corresponding to imbalances and balancing energy prices presented in Table 3.11 and Table 3.12, respectively, the settlement of BRPs and balancing energy, and the net income resulting from the settlement. It can be observed in the table that when all imbalances are covered by BRPs, imbalance prices reflects the real-time cost of balancing energy and the net income resulting from the settlement is zero (when single pricing is applied). On the other hand, if imbalances not covered by BRPs are produced, imbalance prices deviate from cost-reflective prices; as a consequence, the net income resulting from the settlement of imbalances and balancing energy is different from zero.

**Table 3.12: Example 4 - Balancing energy bid curves**

| | Upward $Ebal$ (MWh) | $P_{up}$ (€/MWh) | Downward $Ebal$ | $P_{dw}$ (€/MWh) |
|---|---|---|---|---|
| $BSP_1$ | 10 | **60** | 10 | **45** |
| $BSP_2$ | 10 | **65** | 10 | **40** |
| $BSP_3$ | 10 | **70** | 10 | **35** |

**Imbalances not covered by BRPs** may not only affect cost-reflectiveness of imbalance prices but also distort these prices. For instance, imbalance prices of settlement periods 7 and 8 are inverted in respect with periods 1 and 2. Under a context in which passive balancing is incentivized and (close to) real-time information regarding imbalance prices is provided to market participants, BRPs may have (distorted) incentives to increase production in period 7 and decrease production in period 8, increasing the system imbalance in both cases. In brief, **only balancing energy activated with the purpose of managing imbalances** caused and covered by BRPs should be taken into account in the imbalance settlement, otherwise imbalance prices may be distorted and lead BRPs to increase the system imbalance.

**Table 3.13: Example 4 - Settlement of balancing energy and imbalances applying single imbalance pricing and net income resulting from the settlement**

| | $P_{dev}$ | Imbalance BRP1 | Imbalance BRP2 | Imbalance not covered by BRPs | $Ebal$ |
|---|---|---|---|---|---|
| 1 | 40 | $40 \times 40 = 1{,}600$ | $-200 \times 40 = -800$ | $-200 \times 40 = -800$ | $\mathbf{0}$ |
| 2 | 60 | $-40 \times 60 = -2{,}400$ | $200 \times 60 = 1{,}200$ | $200 \times 60 = 1{,}200$ | $\mathbf{0}$ |
| 3 | 45 | $40 \times 45 = 1{,}800$ | $-200 \times 45 = -900$ | $-100 \times 45 = -450$ | $\mathbf{-4,500}$ |
| 4 | 55 | $-40 \times 55 = -2{,}200$ | $200 \times 55 = 1{,}100$ | $100 \times 55 = 550$ | $\mathbf{5,500}$ |
| 5 | 35 | $40 \times 35 = 1{,}400$ | $-200 \times 35 = -700$ | $-300 \times 35 = -1{,}050$ | $\mathbf{3,500}$ |
| 6 | 65 | $-40 \times 65 = -2{,}600$ | $200 \times 65 = 1{,}300$ | $300 \times 65 = 1{,}950$ | $\mathbf{-6,500}$ |
| 7 | 60 | $40 \times 60 = 2{,}400$ | $-200 \times 60 = -1{,}200$ | $100 \times 60 = 600$ | $\mathbf{-18,000}$ |
| 8 | 40 | $-40 \times 40 = -1{,}600$ | $200 \times 40 = 800$ | $-100 \times 40 = -400$ | $\mathbf{12,000}$ |

In this section, numerical examples were used to support discussion on alternative imbalance settlement arrangements, helping to identify those facilitating or preventing the computation of cost-reflective imbalance prices that incentivizes effective passive balancing. In the following sections, Spanish market design and its outcomes will be analyzed in detail since similar arrangements can be found in other European countries. Furthermore, as an isolated power system with significant penetration of renewable generation, the Spanish case can serve as an interesting example of how inadequate market arrangements can limit an efficient integration of renewable generation.

## 3.2. European imbalance settlement arrangements: a closer look into the Spanish design

As previously discussed in Chapter 2, European market arrangements vary greatly from one country to another. This section briefly compares imbalance settlement arrangements found in selected European countries, as they represent the most relevant designs currently applied in Europe. Spanish arrangements are further described as the basis for the analyses carried out in Section 3.3.

Table 3.14 shows the main imbalance arrangements of Spain, France, the Netherlands, Germany and Denmark. It can be observed in the table that in countries like Spain, France and Denmark a dual price system is used, while the German SOs apply a single price system. It is worth mentioning that dual price is used to settle imbalances of generation units while a single price system is applied to consumption units. In the Netherlands, a dual price system is applied when upward and downward reserves are activated to balance the system within a single settlement period. The Dutch system is briefly explained in Section 3.3.2.

Regarding France, in April 2017 a new imbalance price system will be applied. According to this new system, the main component of the imbalance price used to settle short and long positions will be based on the price of net (upward or downward) balancing energy used to balance the system, which would characterize it as a single imbalance price system (see Section 3.1.1). However, a coefficient “k” is added to/subtracted from the price applied to short/long BRPs in such a way that different prices are applied to different positions[18]. The objective of applying this coefficient is to balance the payments and revenues resulting from the settlement of balancing energy between the SO and BSPs and from the settlement of imbalances between the SO and BRPs. In practice, in France a dual system will still be applied, although BRPs contributing to reduce the system imbalance will no longer be settled at a price based the day-ahead market price.

**Table 3.14: Examples of European imbalance settlement arrangements**

| | **Imbalance price system** | **Imbalance settlement period** | **Publication of** | | |
|---|---|---|---|---|---|
| | | | **Activated bal. energy** | **Bal. energy price** | **Imbalance price** |
| ES | Dual | 1 hour | Few min. after activation (mFRR & RR only) | Few min after activation (mFRR & RR only) | D+1 |
| FR | Dual | 30 minutes | Few min. after activation | Few min after the ISP | Few min after the ISP |
| NL | Single | 15 minutes | Few min. after activation | Few min after activation | D+1 |
| DE | Single | 15 minutes | <15 min after the ISP | Not published | After delivery month |
| DK | Dual for generation | 1 hour | <2 hours after the ISP | <2 hours after the ISP | <2 hours after the ISP |

It can also be seen in the table that imbalance settlement periods range from 15 minutes up to one hour. It is worth mentioning that the SOs of the five selected countries use balancing energy bids to manage congestions during real-time operation. It is also interesting to observe that several SOs are starting to publish (close to) real-time information regarding the activation of balancing energy bids and imbalance prices. This is one of the requirements established in the **Guideline on Electricity Balance** recently approved by European Member States (version of the 16th of March), i.e. that SOs must publish information on the system balance state as soon as possible and no later than 30 minutes after real-time. In this context, if imbalances are properly calculated (and imbalance price reflect balancing energy costs), BRPs will have adequate incentives to support the system balance in real-time; on the contrary, if these are not properly computed BRPs may have distorted incentives and increase the system imbalance.

[18]For more information on the French imbalance price system, see: http://clients.rte-france.com/lang/an/clients_consommateurs/services_clients/dispositif_prix.jsp.

Regarding the provisions established in the Guideline on Electricity Balance, the use of either a **dual price or a single price system** is allowed. In respect to the settlement period, the Guideline establishes that three years after the entry into force of this regulation (expected by the end of 2017), all SOs in Europe shall apply the imbalance settlement period of 15 minutes, although it allows for a joint request of exemption by the SOs of a synchronous area. In this regard, the European Commission proposes in its package of measures launched the 30th of November 2016 (Winter Package) that all SOs change their control area's **settlement period to 15 minutes by 2025**.

Finally, it is also required in the Guideline that SOs 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.

In brief, current European imbalance settlement arrangements are far from been harmonized. Furthermore, nowadays it is not clear which will be the model followed in Europe. The following sections describe and analyze market arrangements in Spain, aiming at shedding light on the discussion of the future design of European balancing market.

### 3.2.1. **Procurement and settlement of balancing energy**

In order to guarantee the balance between demand and generation in real-time, the Spanish SO procures balancing products related to automatic and manual frequency restoration reserves (aFRR and mFRR, respectively) through balancing markets. It is worth mentioning that frequency containment reserve (FCR) is also used in Spain, although it is neither remunerated nor taken into account in the imbalance settlement. The Spanish SO also uses replacement reserve (RR) to deal with larger imbalances between generation and demand. As it can be observed in Table 3.15, which defines balancing services used in Spain, the RR currently used by the Spanish SO have slower maximum activation and longer maximum deployment times than the RR defined in the TERRE project (Trans European Replacement Reserves Exchange), which are equal to 30 minutes and one hour, respectively (CNMC et al., 2016).

Table 3.16 characterizes balancing markets in Spain. In total, there are four markets dedicated to the procurement of different balancing products: the aFRR market, where joint upward and downward aFRR capacity (commonly referred as regulation band) is procured; the mFRR market, where upward and downward mFRR energy are separately procured; the RR market, where upward and downward RR energy are separately procured; and the RR upward capacity market, where upward RR capacity is procured. These markets are described in (Fernandes et al., 2016) and are further discussed in Chapter 4.

**Table 3.15: Definition of balancing services used in Spain**

| Type of reserve | Maximum response time | Maximum deployment time | Definition |
|---|---|---|---|
| FCR | ≤ 30 sec up to 15 min | 15 min | Reserve activated in response to system frequency changes: action of generation units' speed regulators |
| aFRR | ≤ 100 sec up to 15 min | 15 min | Reserve automatically activated to restore the system frequency: automatic variation of generation output |
| mFRR | ≤ 15 min up to 2 hours | 2 hours | Reserve manually activated to restore activated aFRR: variation of generation output and/or pumped storage consumption |
| RR | ≤ 15min up to 3 hours | 4 hours | Online reserve used to manage hourly imbalances larger than 300 MW occurring between two ID market sessions: variation of generation output and/or pumped storage consumption |

As in most European countries and as recommended by ACER, in Spain, only balancing energy prices are considered in the calculation of imbalance prices; costs related to the payment of balancing capacity are socialized among consumers (ENTSO-E, 2015). Regarding payments related to the provision of balancing energy, while mFRR and RR energy are settled at the respective market marginal prices, the (marginal) price of aFRR energy is determined by the (upward/downward) mFRR market bid ladder, taking into account the aFRR energy deployed beyond the activated mFRR.

Accordingly, the settlement of providers of balancing energy is summarized in Equation 3.1 where $BS_{BSP,h}$ represent either a revenue right or a payment obligation assigned to provider "$bsp$" for the provision of upward or downward balancing energy ($Ebal$) within hour "$h$"; and $P_h^{Ebal}$ represents the marginal price of the corresponding product. Since negative prices are not allowed in Spain, the provision of downward (or negative) balancing energy will always result in a payment obligation and the provision of upward balancing energy will always result in a revenue right to corresponding providers.

$$BS_{bsp,h} = Ebal_{bsp,h} \times P_h^{Ebal} \quad (3.1)$$

**Table 3.16: Balancing markets in Spain**

| Product | Capacity settlement | Energy settlement |
|---|---|---|
| aFRR capacity band | Market marginal price (€/MW) | Determined by the mFRR energy bid ladder (€/MWh) |
| mFRR energy | - | Upward or downward energy marginal price (€/MWh) |
| RR energy | - | Upward or downward energy marginal price (€/MWh) |
| RR upward capacity | Market marginal price (€/MW) | Depends on market of activation (€/MWh) |

## 3.2.2. Imbalance settlement mechanism

### 3.2.2.1. Imbalances covered by BRPs

As mentioned in Section 2.2, balance responsibility defines the financial responsibility of BRPs for their production/consumption deviations in respect to corresponding market schedules. In Spain, BRPs include owners of generation units, i.e. generation companies; retailers; direct consumers, i.e. consumers that buy energy directly in the market; and market representatives, i.e. third-parties that represent generation or consumption units in the market (Chaves-Ávila and Fernandes, 2014). Although BRPs can present aggregated offers to the day-ahead and intraday markets, individual generation and consumption units are the basic element for the calculation of energy imbalances. Therefore, all BRPs are required to send individual (production/consumption) market schedules to the SO. In this sense, a single consumption unit is defined for the aggregation of all consumption units within a same BRP (i.e. retailer or direct consumer) and a single renewable generation unit can be composed of several installations of a same technology (e.g. wind, thermal solar, solar PV, etc.) under responsibility of a same BRP (i.e. generation company or market representative). Notice that generation and consumption units cannot be aggregated within a same BRP.

Individual imbalances of generation and consumption units are computed for hourly settlement periods according to Equations 3.2 and 3.3, respectively, where $dev_{gu,h}$ and $dev_{cu,h}$ represent hourly imbalances of generation unit "$gu$" and consumption unit "$cu$"; $E_{gu,h}$ and $E_{cu,h}$ correspond to the energy actually produced and consumed by units "$gu$" and "$cu$", respectively; $MS_{gu,h}$ and $MS_{cu,h}$ represent the ID market schedules of units "$gu$" and "$cu$"; $OS_{gu,h}$ corresponds to upward/downward energy dispatches allocated by the SO to unit "$gu$" up to 15 minutes before real-time for system balancing and/or congestion management purposes[19]; $OS_{cu,h}$ refers to an order of consumption reduction assigned to "$cu$" associated to interruptible load contracts[20]. It is worth mentioning that $E_{cu,h}$ and $MS_{cu,h}$ always take negative values. Therefore, if $|E_{cu,h}|>|MS_{cu,h}+OS_{cu,h}|$, then $dev_{cu,h}$ is negative and "$cu$" is short; if instead $|E_{cu,h}|<|MS_{cu,h}+OS_{cu,h}|$, then $dev_{cu,h}$ is positive and "$cu$" is long.

$$dev_{gu,h} = E_{gu,h} - (MS_{gu,h} + OS_{gu,h}) \tag{3.2}$$

$$dev_{cu,h} = E_{cu,h} - (MS_{cu,h} + OS_{cu,h}) \tag{3.3}$$

Notice that $E_{cu,h}$ refers to energy consumption measured at the generation bus, which is obtained by adding the energy consumption measured at the consumption bus level and corresponding network losses. This value is calculated according to Equation 3.4, where $E_{cu,vl,nt,h}$ refers to the energy consumption measured at the consumption bus for unit "$cu$", which is connected to the voltage level "$vl$" and settled according to a network tariff "$nt$". $Lrcoef_{cu,vl,nt,h}$ refers to the coefficient applied to consumption unit "$cu$" for the allocation of network losses to this unit.

$$E_{cu,h} = E_{cu,vl,nt,h} \times \left(1 + Lrcoef_{cu,vl,nt,h}\right) \tag{3.4}$$

Until 2015, the imbalances of generation units were aggregated according to the following for settlement purposes: (i) regulation areas, (ii) conventional generation units within a same BRP and not incorporated in a regulation area, (iii) technology-specific renewable generation units within a same BRP. Regulation areas constitute an especial type of BRP in Spain which are composed of generation units that comply with the technical requirements for the provision of

[19] $OS_{gu,h}$ does not include balancing energy associated to the Frequency Restoration Process (FRP).
[20] In Spain, interruptible load contracts are used for last resort real-time balancing/congestion management purposes.

aFRR. Notice that regulation areas do not correspond to specific geographical areas. These BRPs are typically owned by large generation companies in Spain (Fernandes et al., 2016). The balancing responsibility of each regulation area is assigned to the generation company owning or representing the generation units within the area.

Imbalances corresponding to (i), (ii) and (iii) were computed according to Equations 3.5, 3.6 and 3.7, respectively. In Equation 3.5, $eAFRR_{RA,h}^{up}$ and $eAFRR_{RA,h}^{dw}$ correspond to upward and downward balancing energy provided by regulation area "RA", respectively. The imbalance of consumption units within a same BRP is calculated as shown in Equation 3.8. Notice that a BRP is short when the resulting hourly imbalance (as calculated in Equations 3.5, 3.6, 3.7, and 3.8) is negative and long when it is positive.

$$dev_{RA,h} = \sum_{gu\epsilon RA}\left[E_{gu,h} - \left(MS_{gu,h} + OS_{gu,h}\right)\right] - \left(eAFRR_{RA,h}^{up} + eAFRR_{RA,h}^{dw}\right) \quad (3.5)$$

$$dev_{BRP,h}^{cg} = \sum_{cg\in BRP} dev_{cg,h} \quad (3.6)$$

$$dev_{BRP,h}^{rg} = \sum_{rg\in BRP} dev_{rg,h} \quad (3.7)$$

$$dev_{BRP,h}^{cu} = \sum_{cu\in BRP} dev_{cu,h} \quad (3.8)$$

#### 3.2.2.2. **Imbalances not covered by BRPs**

*I. Imbalances resulting from real-time congestion management*

As explained in Section 3.1.3, in general, SOs use balancing energy not only for balancing the system but also for congestion management purposes. In Spain, although the SO uses upward or downward mFRR bids to solve grid constraints in real-time, regulation establishes that the activation of mFRR for congestion management should affect neither mFRR energy prices nor imbalance prices.

Despite this, the management of network congestions in real-time generates an imbalance which is dealt with the activation of aFRR and/or mFRR (and, in some cases, RR) in the opposite direction of the real-time redispatch. In this sense, if downward (or negative) generation redispatch is needed in real-time, upward balancing energy is required to balance this production reduction; on the other hand, if upward (or positive) generation redispatch is needed in real-time, downward balancing energy is required to balance this production increase. A last resort option to handle network congestions in real-time is the activation of interruptible loads. Load curtailment always refers to an upward redispatch, since generation is increased in respect to consumption, which produces a positive imbalance.

The imbalance caused by real-time congestion management is shown in Equation 3.9, where $eRTCM_h$ corresponds to the net amount of generation redispatched during hour "$h$" to manage network constraints in real-time and $OS_{cu,h}$ refers to the consumption reduction assigned to unit "$cu$" with an interruptible load contract.

$$dev_h^{rtcm} = eRTCM_h + \sum_{cu} OS_{cu,h} \qquad (3.9)$$

*II. Imbalances resulting from differences between estimated and real network losses*

Before the liberalization of the Spanish electricity retail market, distribution companies were financially responsible for the imbalances of their customers as well as for those produced by differences between estimated network losses and actual network losses. Estimated losses were calculated by the application of standard coefficients established by the Spanish Government to each type of customer (i.e. according to consumption voltage level and network tariff).

However, since the liberalization of the Spanish electricity retail market in 2009, when electricity retailers started being responsible for energy procurement, until March 2015, imbalances resulting from the difference between estimated network losses and measured losses produced imbalances were not covered by any BRP. This imbalance is calculated according to Equation 3.10, where $dev_h^{loss}$ refers to the hourly difference between effectively measured transmission and distribution network losses ($Loss_h$) and total estimated losses ($\sum_{cu,vl,nt}[E_{cu,vl,nt,h} \times Lcoef_{vl,nt,p}]$). $Lcoef_{vl,nt,p}$ represents the coefficient applied to customers connected to the voltage level "$vl$" and settled according to a network tariff "$nt$". Depending on the voltage level and on the network tariff applied, different coefficients were applied for up to six different hourly periods "$p$".

$$dev_h^{loss} = Loss_h - \sum_{cu,vl,nt}[E_{cu,vl,nt,h} \times Lcoef_{vl,nt,p}], \quad \forall\, h \in p \qquad (3.10)$$

As well as energy consumption values, $Loss_h$ always take a negative value; therefore, if $|Loss_h|$>$|\sum_{cu,vl,nt}[E_{cu,vl,nt,h} \times Lcoef_{vl,nt,p}]|$, $dev_h^{loss}$ is negative; if $|Loss_h|$< $|\sum_{cu,vl,nt}[E_{cu,vl,nt,h} \times Lcoef_{vl,nt,p}]|$ $dev_h^{loss}$ is positive.

In June 2014, the Spanish Government introduced a regulatory change by which an hourly coefficient was estimated for each customer according to its voltage level and network tariff ($Lcoef_{cu,vl,nt,h}$), which was replaced in April 2015 by a “real” hourly coefficient ($Lrcoef_{cu,vl,nt,h}$). Notice that this “real” coefficient is calculated in such a way that all measured network losses are allocated to BRPs, as shown in Equation 3.11.

$$Loss_h = \sum_{cu,vl,nt,h}[E_{cu,vl,nt,h} \times Lrcoef_{cu,vl,nt,h}] \qquad (3.11)$$

The differences between estimated and actual network losses produced important imbalances during the period 2009-2013, which were handled mostly by the activation of RR. These imbalances excessively penalized BRPs, inasmuch they increased the activation of balancing resources.

#### 3.2.2.3. System overall imbalance

As explained in Section 3.1.3, the overall system imbalance over a certain settlement period is determined by the net activation of balancing energy during the same period. In the Spanish case, the system imbalance ($dev_h^{syst}$) is given by net amount if balancing energy from aFRR, mFRR and RR over an hourly settlement period, which in turn is determined by the imbalances calculated in the previous subsections, as shown in Equation 3.12:

$$dev_h^{syst} = \sum_{RA} dev_{RA,h} + \sum_{BRP} dev_{BRP,h}^{cg} + \sum_{BRP} dev_{BRP,h}^{rg} + \sum_{BRP} dev_{BRP,h}^{cu} + dev_h^{rtcm} = -\left(eAFRR_h^{up} + eAFRR_h^{dw} + eMFRR_h^{up} + eMFRR_h^{dw} + eRR_h^{up} + eRR_h^{dw}\right) \qquad (3.12)$$

Total hourly upward balancing energy activated from aFRR, mFRR and RR are represented by $eAFRR_h^{up}$, $eMFRR_h^{up}$, and $eRR_h^{up}$, respectively, while total downward balancing energy from aFRR, mFRR and RR are represented by $eAFRR_h^{dw}$, $eMFRR_h^{dw}$, and $eRR_h^{dw}$, respectively. If

$dev_h^{syst}$ is positive, the system is long; if $dev_h^{syst}$ is negative, the system is short. It is emphasizing that from April 2015 the term $dev_h^{loss}$ was eliminated, as discussed previously Section 3.2.3.2.

## 3.2.3. **Settlement of imbalances**

### 3.2.3.1. **Settlement of imbalanced BRPs**

In Spain, imbalances are settled according to a dual pricing system, as shown in Table 3.17, where $IP_h^+$ and $IP_h^-$ represent hourly imbalance prices applied to long and short BRPs, respectively; $AP_h^{up}$ and $AP_h^{dw}$ refer to the weighted average prices of activated upward and downward balancing energy from aFRR, mFRR, and RR, respectively; finally, $P_h^{DA}$ refers to the day-ahead market price.

**Table 3.17: Imbalance prices in Spain**

| | | System imbalance | |
|---|---|---|---|
| | | Positive | Negative |
| BRP imbalance | Positive | $IP_h^+ = Min(AP_h^{dw}, P_h^{DA})$ | $IP_h^+ = P_h^{DA}$ |
| | Negative | $IP_h^- = P_h^{DA}$ | $IP_h^- = Max(AP_h^{up}, P_h^{DA})$ |

$AP_h^{up}$ and $AP_h^{dw}$ are calculated according to Equations 3.13 and 3.14, where $P_h^{eAFRRup}$, $P_h^{eMFRRup}$, and $P_h^{eRRup}$ correspond to the marginal prices of activated upward balancing energy, and $P_h^{eAFRRdw}$, $P_h^{eMFRRdw}$, and $P_h^{eRRdw}$ correspond to the marginal prices of activated downward balancing energy from aFRR, mFRR, and RR, respectively.

$$AP_h^{up} = \frac{eAFRR_h^{up} \times P_h^{eAFRRup} + eMFRR_h^{up} \times P_h^{eMFRRup} + eRR_h^{up} \times P_h^{eRRup}}{eAFRR_h^{up} + eMFRR_h^{up} + eRR_h^{up}} \tag{3.13}$$

$$AP_h^{dw} = \frac{eAFRR_h^{dw} \times P_h^{eAFRRdw} + eMFRR_h^{dw} \times P_h^{eMFRRdw} + eRR_h^{dw} \times P_h^{eRRdw}}{eAFRR_h^{dw} + eMFRR_h^{dw} + eRR_h^{dw}} \tag{3.14}$$

Imbalances calculated in Equations 3.5, 3.6, 3.7, and 3.8 are settled separately according to Equation 3.15, where $dev_{BRP,h}$ represents the imbalance calculated in each of the referred equations; $IP_h$ refers to the imbalance price computed according to Table 3.17; and $IS_{BRP,h}$ may refer to either a payment obligation or a revenue right assigned to the corresponding BRP. Since negative prices are not allowed in Spain, the settlement of short BRPs results always in a payment obligation and the settlement of long BRPs in a revenue right assigned to corresponding BRPs, as previously mentioned.

$$IS_{BRP,h} = dev_{BRP,h} \times IP_h \tag{3.15}$$

#### 3.2.3.2. Settlement of imbalances not covered by BRPs

Imbalances caused by differences between actual and estimated network losses ($dev_h^{loss}$) were settled at the day-ahead market price, as shown in Equation 3.16. Payment obligations/revenue rights resulting from this settlement were added to/deduced from the costs of regulated activities (i.e. transmission and distribution).

$$IS_h^{loss} = dev_h^{loss} \times P_h^{DA} \tag{3.16}$$

Imbalances caused by real-time congestion management ($dev_h^{rtcm}$) are not settled.

### 3.2.4. Net income resulting from the settlement of imbalances and balancing energy

The net income resulting from the settlement of imbalances and balancing energy is allocated among load units in proportion to their consumption (i.e. $E_{cu,h}$, in Equation 3.4). It is worth mentioning that the costs associated to congestion management and balancing capacity procurement are also transferred to consumption units. Consequently, when the net income resulting from the settlement of imbalances and balancing energy is positive, part of the above-mentioned costs are compensated.

## 3.3. Evidences of distortions resulting from inadequate imbalance settlement arrangements

In this section, Spanish market data are used to estimate the impact of poor imbalance settlement designs on system balancing costs and on imbalance costs allocated to BRPs. Due to the lack of public data on the imbalances allocated to each BRP, as calculated in Equations 3.5, 3.6, 3.7 and 3.8, for the purpose of the analysis presented in this section it is assumed that a single BRP is responsible for the imbalances of regulation areas, conventional generation units not included in regulation areas, renewable generation units and consumption units. Therefore, the results of the calculations carried out here are an approximation of actual market results and can be used for comparison purposes only.

As discussed in Section 3.1.1, if remaining balancing arrangements are properly defined, the settlement of balancing energy and imbalances under a dual imbalance pricing system would lead to an overall positive net settlement income while the settlement of imbalances under a single pricing system would lead to a nil net settlement income. In order to obtain a first approximation of the impact of distortions caused by inadequate imbalance settlement arrangements, the hourly average net income resulting from the settlement of balancing energy and imbalances in Spain in 2012, 2013 and 2014 was computed for the following cases:

- Case A: Imbalances are settled according to current arrangements in Spain.
- Case B: Imbalances are settled according to current arrangements in Spain but only for those settlement periods during which the net balancing energy activated from aFRR, mFRR and RR were all positive or all negative (i.e. settlement periods with, for instance, positive balancing energy from aFRR and negative balancing energy from mFRR, were eliminated of the analysis). The net income estimated in this case is an approximation of the net income that could be obtained in case **the imbalance settlement period is reduced**, for instance, to 15 minutes, when the probability of activating balancing energy in only one direction is increased).
- Case C: Imbalances are settled according to current arrangements in Spain considering that imbalances not covered by BRPs (i.e. $dev_h^{loss}$ and $dev_h^{rtcm}$) are settled as imbalances covered by BRPs (i.e. according the corresponding imbalance price). In this case, distortions related to **imbalances not covered by BRPs are eliminated**.
- Case D: Imbalances are settled according to current arrangements in Spain but only for those settlement periods during which the net balancing energy activated from aFRR, mFRR and RR were all positive or all negative and considering that imbalances not covered

by BRPs are settled at corresponding imbalance prices. The net income computed in this case is an approximation of the net income that could be obtained in case **the imbalance settlement period is reduced and all imbalances are covered by BRPs**.

- Case E: Imbalances are settled according **single imbalance pricing** instead of dual pricing and considering the **same hypotheses assumed in Case D**. In this case the imbalance price is determined by the weighted average price of activated balancing energy (i.e. $AP_h^{up}$ or $AP_h^{dw}$, as shown in Table 3.1).

Figure 3.2 presents the results for Cases A to E. First, it can be observed in the figure that even though imbalances are settled according to a dual imbalance pricing system, the settlement of balancing energy and imbalances in Spain result in an overall negative net income (Case A).

It is worth noticing that while average net incomes observed in 2012 and 2013 are similar, in 2014 they are significantly reduced, in absolute terms, with respect to previous years. This is explained in great part by the introduction of hourly coefficients for the allocation of network losses to final electricity customers, as discussed in Section 3.2.2.2. In this respect, total $dev^{loss}$ was reduced by 60% in 2014 in respect to 2012. Similarly, the average net income calculated in Case A is 60% lower than resulting net income for 2012.

In Case B, the hourly average net income increases by 28%, 26% and 82% in 2012, 2013, and 2014, respectively, in respect to Case A, although it remains negative due to distortions related to imbalances not covered by BRPs. In this respect, it is worth mentioning that distortions regarding long settlement periods can be further reduced if one takes into account that balancing energy costs can be better allocated to BRPs when the settlement period is reduced. Even though in Case B only periods with net balancing energy from aFRR, mFRR and RR had the same signs were considered, upward and downward balancing energy from a same reserve type might have been activated, generating balancing costs to the system that are not recovered though imbalance prices.

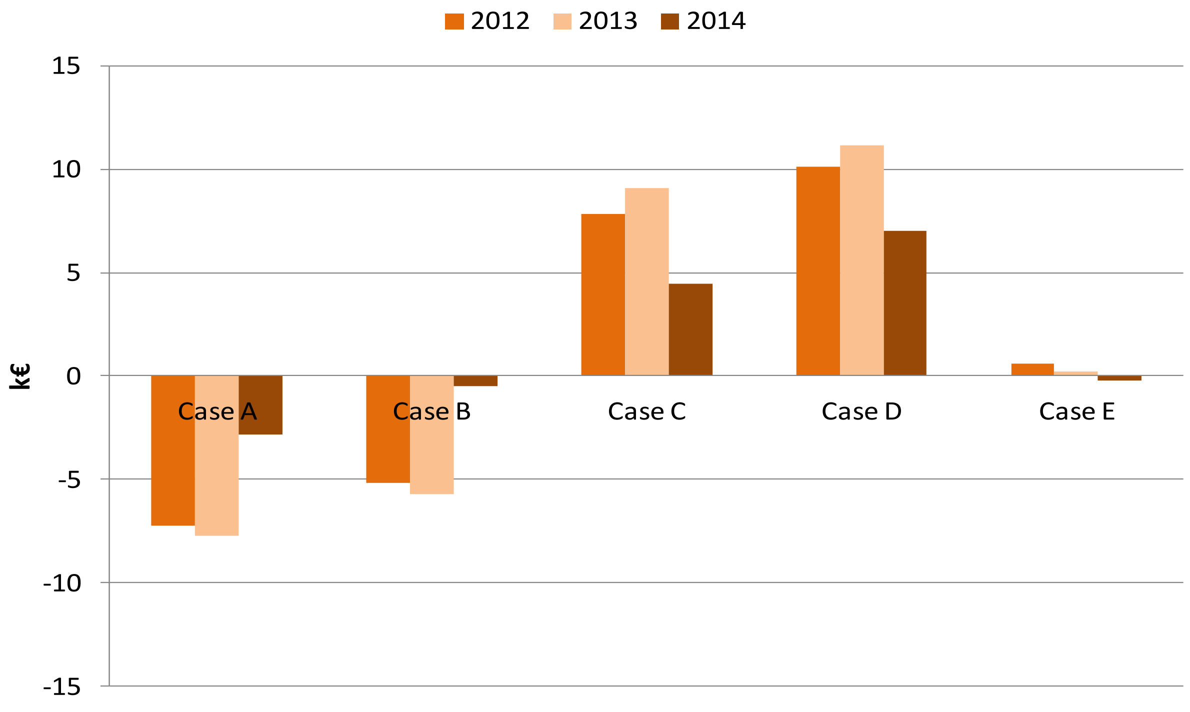



**Figure 3.2: Hourly average net income resulting from the settlement of balancing energy and imbalances in Spain in five cases**

In Case C, where it is assumed that all imbalances are covered by BRPs, the net income resulting from the settlement of balancing energy and imbalances according to a dual pricing system is positive, even considering settlement periods during which net balancing energy from aFRR, mFRR and RR have different signs. When these settlement periods are not considered (Case D), the hourly average net income increases by 29%, 23% and 59% in 2012, 2013, and 2014, respectively, compared to Case C.

Finally, if the above mentioned distortions are eliminated and single pricing is applied (Case E), the estimated hourly average net income is significantly reduced in comparison to Case D: 628€ in 2013, 235€ in 2013 and -159€ in 2014. This remaining net income can be explained by the fact that, in general, within a settlement period both positive and negative aFRR balancing energy is deployed to manage imbalances. However, the data used in this exercise corresponded to net amounts only.

In the next subsections, distortions related to dual imbalance pricing, long settlement period and existence of imbalances not covered by BRPs are further discussed.

### 3.3.1. **Dual imbalance pricing**

As observed in Figure 3.2, when part of the effect of long settlement periods is eliminated and all imbalances are covered by BRPs, the net income obtained from the settlement of balancing energy and imbalances under a dual imbalance pricing system (Case D) is significantly higher compared to when single imbalance pricing is applied (Case E). In this respect, Figure 3.3 presents total balancing energy costs allocated to each type of BRP in Cases D and E, respectively. It is worth mentioning that balancing costs associated to $dev_h^{loss}$ were included in the costs allocated to consumption units.

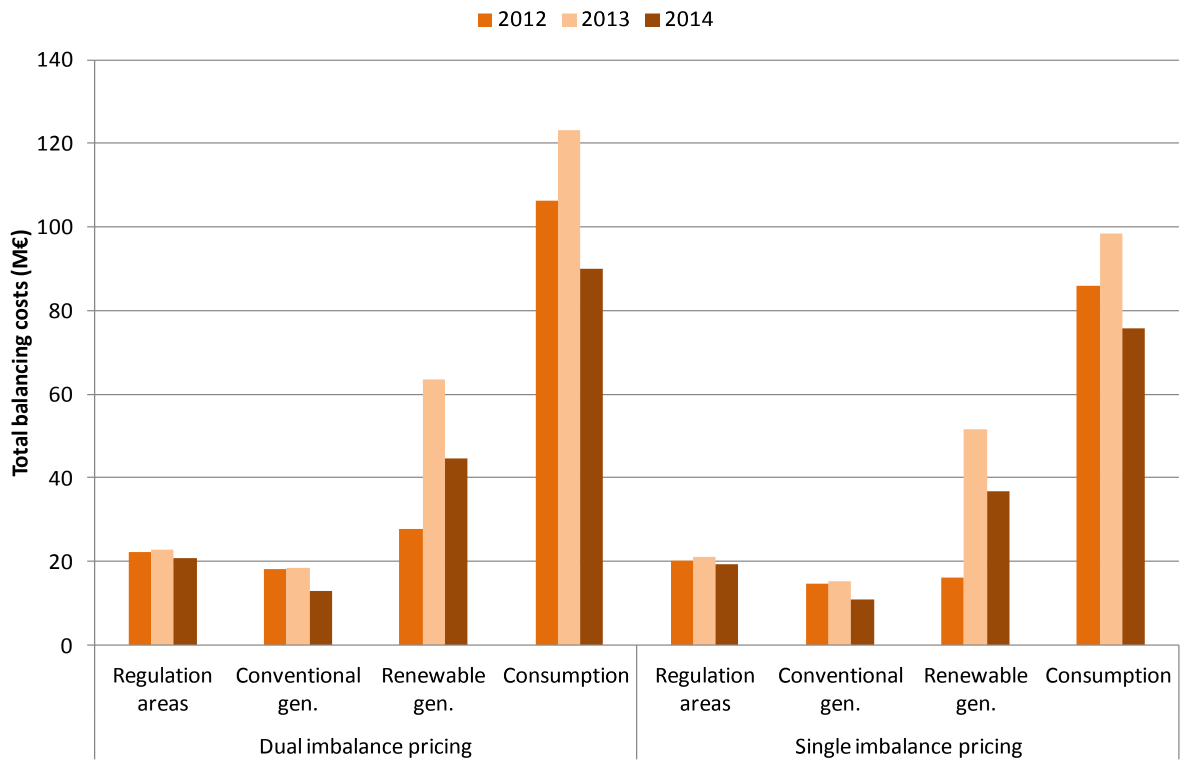



**Figure 3.3: Total balancing energy costs allocated to BRPs under dual and single imbalance pricing systems**

It can be observed in the figure that total balancing costs for all types of BRPs reduce when single imbalance pricing is applied instead of dual imbalance pricing. As explained in Section 3.1.1, under a single imbalance pricing system, BRPs are compensated when their imbalances reduce the system overall imbalance, which gives them an incentive to support the system balance. On the contrary, under a dual imbalance pricing system BRPs that help to reduce the system imbalance are not compensated, which provides them an incentive to follow their schedules regardless the system balance state.

Regarding the results in Figure 3.3, it is worth noticing that, as expected, the lower reduction in balancing costs when passing from a dual pricing system to a single pricing system is observed for large generation portfolios represented by the regulation areas, followed by conventional generation units not included in regulation areas and consumption units. This is explained by the fact that, under a dual pricing system, large BRPs beneficiates significantly from imbalance netting within its portfolio facing relatively lower balancing costs than smaller BRPs, as discussed in Section 3.1.1. The analysis shows a reduction in average balancing allocated to regulation areas, conventional generation units and consumption units in the period 2012-2014 of 7%, 17% and 18%, respectively, when dual pricing is replaced by single pricing.

On the other hand, average balancing costs allocated to renewable generation units presents the highest reduction (26% over the whole analyzed period). This is explained by the fact that these units are in general included in small BRPs that beneficiate very little from imbalance netting.

### 3.3.2. **Long settlement period**

As discussed in Section 3.1.2, BRPs may be out of balance several times within long settlement periods while being balanced over the whole period. One of the consequences of this is the activation of upward and downward balancing energy bids within a single settlement period. As previously explained, since in most European power systems the imbalance price applied to BRPs aggravating the overall system imbalance is based either on the price of upward or downward balancing energy (depending on overall imbalance direction), part of the imbalance costs incurred by the SO when activating both upward and downward balancing energy bids within a single settlement period is not recovered.

In order to demonstrate how the activation of both upward and downward balancing energy bids increase when longer settlement periods are used, information regarding the activation of balancing energy in Spain and in the Netherlands is compared[21]. Notice that in Spain hourly settlement periods are used while in the Netherlands quarterly-hour settlement periods are applied.

Table 3.18 presents the percentage of settlement periods during which both upward and downward balancing energy bids are activated considering 15-minute, 30-minute and hourly periods in the Netherlands and the percentage number of hours with the activation of both upward and downward balancing energy in Spain during 2012, 2013 and 2014.

**Table 3.18: Percentage of number of settlement periods with activation of both upward and downward balancing energy**

| | Netherlands | | | Spain |
|---|---|---|---|---|
| | 15-minute | 30-minute | Hourly | Hourly |
| 2012 | 11.5% | 27.1% | 45.3% | 51.3% |
| 2013 | 12.5% | 28.5% | 45.2% | 52.6% |
| 2014 | 6.9% | 20.6% | 38.5% | 54.5% |

As expected, it can be observed in the table that the activation of both upward and downward balancing energy bids increases for longer settlement periods. It is worth noticing that the number of settlement periods during which both upward and downward reserves are activated in Spain is higher than in the Netherlands when an hourly period is considered. This can be explained by the fact that passive balancing is strongly incentivized in the latter country, as mentioned in Section 2.2.2. Therefore, in the Netherlands BRPs have incentives to support the system balance in real-time, preventing the activation of balancing energy bids. It is also worth noticing that even for short settlement periods the activation of both upward and downward reserves cannot be completely avoided, although it is significantly reduced when compared to the case of long settlement periods.

In this respect, in the Netherlands, imbalances are settled according to the system "regulation state", which may be the following ones: (a) 0: balancing energy bids are not activated; (b) +1: only upward balancing energy is activated; (c) -1: only downward balancing energy is activated; (d) 2: both upward and downward reserves are activated (TENNET, 2011). Imbalance prices defined for each of these regulation states are presented in Table 3.19, where $AP^{up,dw}$

[21] Information within 15-minute intervals is not available for the Spanish system

corresponds to the average between the lowest upward balancing energy price bid and the highest downward balancing energy price bid within the settlement period and $MP^{up}$ and $MP^{dw}$ represent the marginal prices of upward and downward balancing energy activated within the settlement period, respectively.

**Table 3.19: Imbalance prices based on the system regulation states (Dutch model)**

| | | System regulation state | | | |
|---|---|---|---|---|---|
| | | 0 | -1 | +1 | 2 |
| BRP imbalance | Long | $+AP^{up,dw}$ | $+MP^{up}$ | $+MP^{dw}$ | $+MP^{dw}$ |
| | Short | $-AP^{up,dw}$ | $-MP^{up}$ | $-MP^{dw}$ | $-MP^{up}$ |

According to the Dutch Scheme, imbalances are settled mainly according to a single imbalance pricing system and according to a dual pricing when both upward and downward balancing energy is required to balance the system within a single settlement period. The objective of this design is to provide incentives for all BRPs to avoid imbalances in any direction. The Dutch imbalance pricing system has been pointed out by Chaves-Ávila et al. (2014a) as a good practice in order to avoid strategic behavior from BRPs.

Figure 3.4 compares the settlement of BRPs in Spain according to the current dual imbalance pricing system and to the Dutch imbalance settlement design (i.e. imbalance price based on regulation states). It can be observed in the figure that balancing costs are slightly reduced for all types of BRPs (3.1%, 7.3% and 2.9% in average for regulation areas, conventional generation units and renewable units, respectively) except for consumption units, whose average balancing costs increase by 83%.

Regarding these results, cost reductions are very much limited due to the fact that during more than 50% of the hours the Spanish system is in regulation state 2. Compared to the imbalance system applied in Spain, the Dutch imbalance pricing system penalizes all BRPs when the system is in regulation state 2. Notice that if the imbalance settlement period is reduced, the activation of upward and downward reserves within a single settlement period is avoided and, consequently, single imbalance pricing would apply during a higher number of settlement periods.

This significant balancing cost increment observed for consumption units is explained in great part by the imbalance produced by differences between estimated and actual network losses

($dev_h^{loss}$). These imbalances mostly aggravated the system imbalance, in which case responsible market parties are strongly penalized when imbalance pricing based on the system regulation state is implemented.

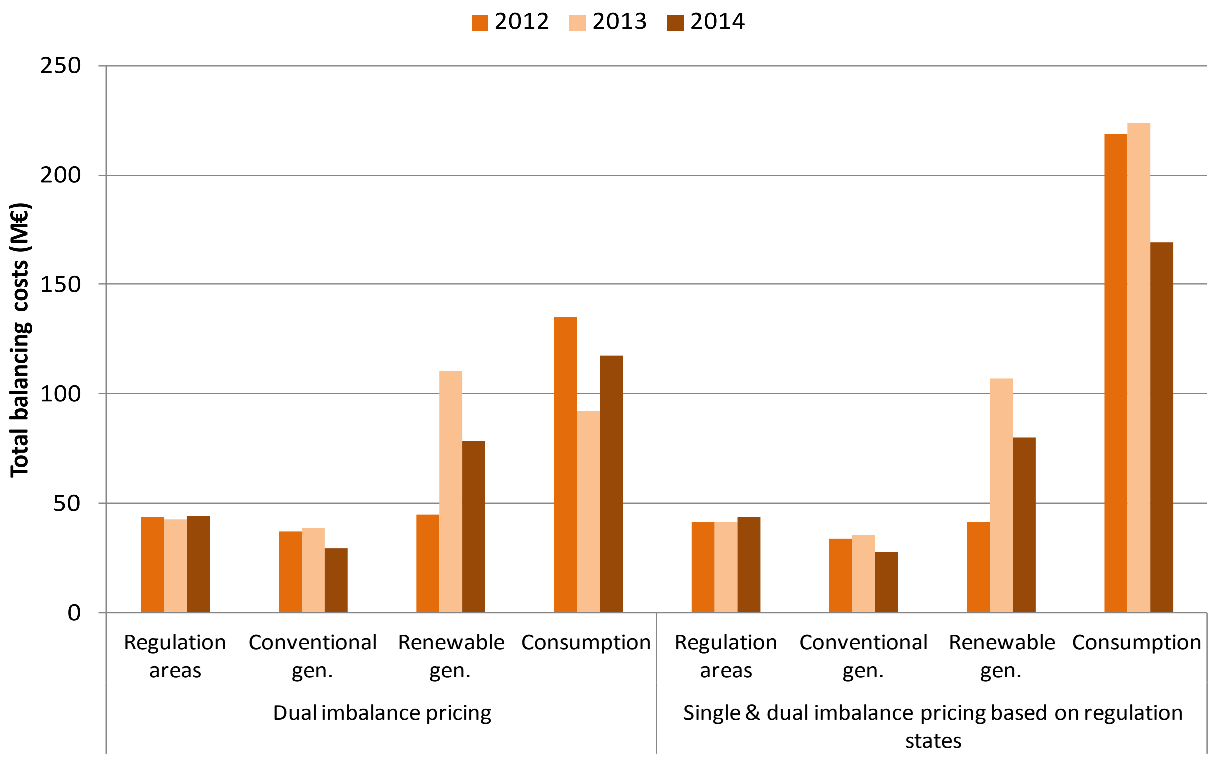



**Figure 3.4: Total balancing energy costs allocated to BRPs when imbalances are settled according to the Spanish imbalance pricing system and according to single and dual pricing based on regulation states**

For this reason, it is recommended that imbalance prices based on the system regulation state is only applied if adequate balancing arrangements are in place, such as the definition of a short imbalance settlement period and the elimination of imbalances not covered by BRPs.

### 3.3.3. Imbalances not covered by BRPs

This section focuses on the distortions caused by imbalances related to the real-time congestion management process ($dev_h^{rtcm}$). In order to estimate the impact of distortions related to $dev_{rtcm,h}$, first, volumes of activated balancing energy and corresponding marginal prices are calculated with and without considering the imbalance $dev_h^{rtcm}$. For simplification purposes, only mFRR energy bid curves are used in this analysis (i.e. it is assumed that only mFRR is used to balance the system in real-time). These mFRR prices are obtained from hourly balancing energy bid curves with and without considering the volume of $dev_h^{rtcm}$, according to the following.

A. Considering $dev_h^{rtcm}$:
   i. if $\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} + dev_h^{rtcm} > 0$, then $|eMFRR_h^{dw}| = |\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} + dev_h^{rtcm}|$
   ii. if $\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} + dev_h^{rtcm} < 0$, then $|eMFRR_h^{up}| = |\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} + dev_h^{rtcm}|$

B. Without considering $dev_h^{rtcm}$
   i. if $\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} > 0$, then $|eMFRR_h^{dw}| = |\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu}|$
   ii. if $\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu} < 0$, then $|eMFRR_h^{up}| = |\sum_{gu} dev_{gu\in ra} + \sum_{cg} dev_{cg\notin ra} + \sum_{rg} dev_{rg\notin ra} + \sum_{cu} dev_{cu}|$

As previously mentioned, due to the lack of public data on the imbalances allocated to each BRP, for the purpose of the analysis imbalances are calculated for the aggregation of: i) all generation units belonging to a regulation area “ra”; ii) all conventional generation units not incorporated in a regulation area; iii) all renewable units of a specific technology type not incorporated in a regulation area; and iv) all consumption units.

It is also important to notice that, according to the calculations made in Cases A and B, it is implicitly assumed that balancing energy is activated in only one direction (i.e. upwards and downwards) over a single settlement period.

Table 3.20 presents the number of settlement periods within a year during which imbalances related to the congestion management process ($dev_h^{rtcm}$) are either positive or negative; the number of periods during which these imbalances increase or decrease the amount of upward ($Ebal^{up}$) or downward balancing energy ($Ebal^{dw}$) required to balance the system; and the number of periods during which the system overall imbalance direction is changed (i.e. upward balancing energy is required instead of downward balancing energy and vice-versa).

**Table 3.20: Impact of imbalances related to the congestion management process on the requirements of upward and downward balancing energy**

| | Number of settlement periods (hours) | | | | | |
|---|---|---|---|---|---|---|
| | $dev_h^{rtcm}$ <> 0 | $Ebal^{dw}$ is reduced | $Ebal^{dw}$ is increased | $Ebal^{up}$ is reduced | $Ebal^{up}$ is increased | $Ebal^{up} \rightarrow Ebal^{dw}$ |
| 2012 | 4,153 | 755 | 835 | 150 | 1,200 | 1034 |
| 2013 | 5,142 | 1,234 | 474 | 317 | 1,196 | 1,836 |
| 2014 | 4,847 | 953 | 516 | 326 | 1,257 | 1,628 |

Once mFRR prices are obtained from hourly mFRR bid curves, the net income resulting from the settlement of imbalances and balancing energy in Spain is computed for cases A and B. Notice that in case A (i.e. when $dev_h^{rtcm}$ is considered), $dev_h^{rtcm}$ is not settled, as explained in Section 3.2.2.2.

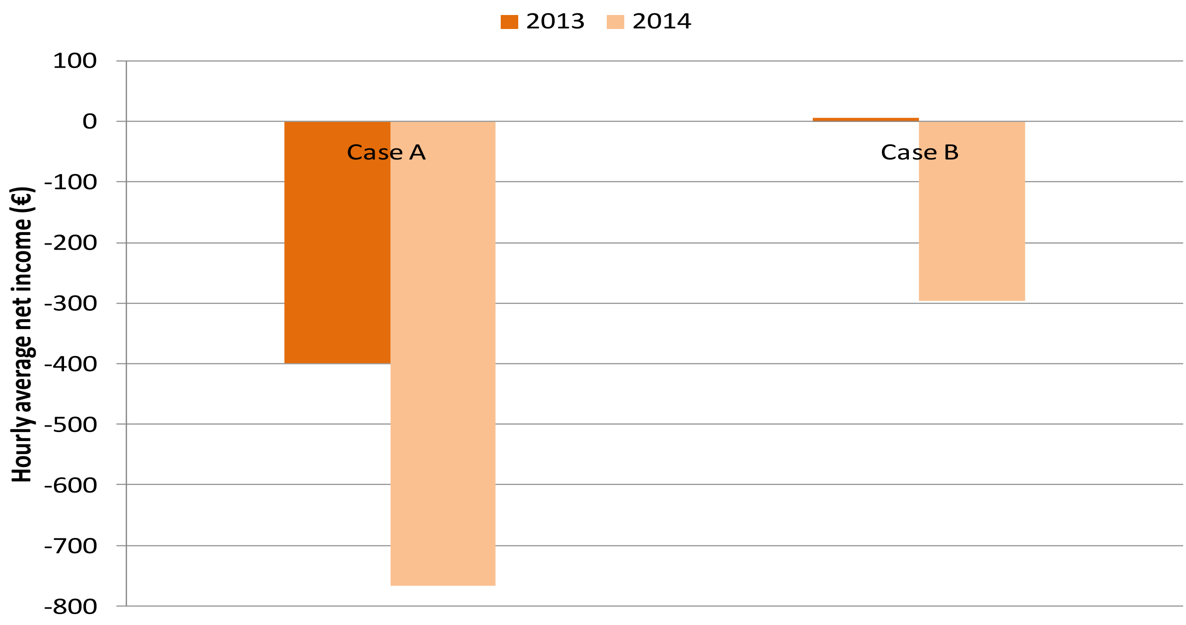



**Figure 3.5: Hourly average net income resulting from the settlement of balancing energy and imbalances with (Case A) and without (Case B) considering imbalances not covered by BRPs**

Figure 3.5 presents the hourly average net income resulting from the settlement of balancing energy and imbalances for cases A and B for 2013 and 2014 considering a single imbalance pricing system. It can be observed in the figure that the net income is significantly increased when imbalances not covered by BRPs do not influence the imbalance settlement: 102% in 2013, and 61% in 2014.

Finally, regarding the interference of congestion management with imbalance prices, it is important to point out that other authors propose more adequate methods to allocate transmission congestion costs, such as Rau (2000), Rubio and Pérez-Arriaga (2000) and Olmos and Neuhoff (2006).

## 3.4. Conclusions

This chapter provided a detailed discussion on imbalance settlement arrangements leading to cost-reflective allocation of balancing costs and providing incentives for effective passive balancing. A real case example – the Spanish market design – was described and related data was used to compare the outcomes of different arrangements and identify best practices. The main conclusions of the analyses carried out in this chapter a listed below:

- First, all imbalances must be covered by a BRP. If there is no market agent financially responsible for a certain type of imbalances, there will be no incentives for the reduction of these imbalances and the corresponding amount of balancing products procured to manage those imbalances, in which case BRPs are excessively penalized.
- In this respect, it is also very important establish separate mechanisms for cost recovery related to balancing energy used for purposes other than managing imbalances caused by BRPs. As discussed in this chapter, balancing energy used and/or activated due to congestion management must not affect imbalance prices.
- Second, a short imbalance settlement period, preferably quarterly-hour periods, will lead to a more efficient cost-reflective allocation of imbalance costs since the activation of balancing energy bids will, in most times, be reduced at the same time that the identification of BRPs causing the imbalance improves.
- Finally, provided that adequate arrangements regarding the settlement period and the calculation of imbalances are in place, single imbalance pricing allows for the recovery of balancing costs, while providing fair allocation of balancing costs and incentivizing BRPs to support the system balancing, in particular when real-time

information regarding the system balancing state is provided. Penalties and/or coefficients that do not reflect the value of energy in real-time should not be used.

# Chapter 4: Arrangements for efficient active balancing

In Chapter 3, theoretical and empirical analyses were carried out to identify distortions derived from inadequate imbalance settlement designs. Based on those, recommendations for arrangements leading to cost-reflective imbalance prices, which provide incentives for passive balancing, were proposed. Apart from passively balancing the system, renewable generators can also contribute to active balancing by participating in balancing markets. However, as pointed out in Chapter 2, current European balancing market designs may limit the participation of renewable producers in those markets. In this context, this chapter discusses alternative arrangements for the design balancing markets aiming at identifying those facilitating the contribution of renewable producers to active balancing. For this purpose, analyses based on Spanish market data are carried out. Based on those and on evidence from the recent experience on the integration of renewable generation in balancing markets in Spain, recommendations for the improvement of European balancing market arrangements are proposed. Chapter 4 is divided into three main sections:

I. First, arrangements that foster competition in balancing markets, facilitating the participation of renewable producers in active balancing, are discussed from a theoretical point of view.
II. After that, a review of the Spanish balancing market design is provided as an example of similar designs found in other European countries.
III. Finally, empirical analyses based on Spanish market data are carried out to support the discussion. Lessons from the participation of renewable generators in active balancing in Spain are also used to propose policy recommendations on the design of European balancing markets.

## 4.1. Flexible balancing market arrangements

One of the core elements needed in order to achieve **efficiency in balancing markets** is the existence of a consistent framework **to foster competition** among BSPs (ACER, 2014). In general, **barriers to the participation** of new potential suppliers in active balancing – in particular renewable generators – are related to the existence of market arrangements that have been designed based on the characteristics of traditional suppliers of balancing services, as previously discussed on Chapter 2. These arrangements refer mainly to (i) the definition of balancing products, (ii) gate-closure times far ahead of real-time operation and (iii) absence of balancing prices that reflect real-time operating conditions (and, consequently, real-time balancing energy provision costs).

In order to incentivize the participation of all potential suppliers in balancing service provision and increase competition in balancing markets, balancing products should be procured through **competitive mechanisms**. Equally important is the establishment of market arrangements that are flexible enough to facilitate the participation of providers with different technical characteristics and capabilities. The following subsections discuss arrangements that improve **flexibility in balancing markets**.

### 4.1.1. Arrangements related to the definition of balancing products

One of the main arrangements contributing to higher competition (and efficiency) in balancing markets is the definition of **separated markets** for the procurement of balancing capacity and for the activation of balancing energy. As explained in Section 2.3.1, the main difference between separated and **joint procurement** of balancing capacity and balancing energy products corresponding to the same balancing service is that in the latter case only BSPs with a contract for the provision of balancing capacity can provide balancing energy in real-time.

One of the main drawbacks of joint procurement of capacity and energy products is that balancing capacity is typically procured far ahead of real-time operation and for reasons other than balancing purposes, as discussed in Section 2.2. This puts renewable producers and other small players at a disadvantage in respect to conventional providers of balancing services since the former have low flexibility in the long term, i.e. they cannot accurately forecast production capability far ahead of real-time.

Furthermore, **balancing capacity and balancing energy provision costs** may differ significantly for different BSPs, especially taking into account the time between the gate-closure for balancing capacity bids and real-time activation of balancing resources. For instance, given the high level of uncertainty regarding resource (e.g. wind) availability far ahead of real-time, renewable generators typically face higher balancing capacity costs (i.e. the costs of keeping capacity available for the SO) than conventional generators. On the other hand, closer to real-time, renewable producers may provide cheaper balancing energy than conventional generators, provided that the primary resource is available.

For **example**, over an off-peak hour, several thermal generators are operating above their minimum operational output; the hourly day-ahead market marginal price is $P_h^{DA} = 50$ €/MWh; variable fuel costs of thermal generators operating during this hour range from 30 to 40 €/MWh. In this case, upward balancing capacity provision costs for these generators would range, approximately, from 10 up to 20 €/MWh (considering, for simplification purposes, that the cost incurred for the provision of upward balancing capacity correspond to the opportunity cost of not selling production in the day-ahead market). Assuming that an intermittent renewable power producer, which is operating in this same hour, has a variable production cost of 5 €/MWh. For this producer, upward balancing capacity provision cost would be, at least, 45 €/MWh, i.e. its opportunity cost of not producing during this hour (and, consequently, not receiving$P_h^{DA}$) less its variable production cost (cost it would save in case of not operating during this hour). In this case, in the balancing market balancing capacity should be allocated to the conventional generators which face lower capacity costs.

Now, it is assumed that, closer to real-time, there is more availability of renewable resources. If balancing capacity and balancing energy are procured separately and balancing energy bids are sent closer to real-time, renewable producers could offer upward balancing energy at price around its variable costs (i.e. in the range of 5-10 €/MWh in this example). This would reduce or avoid the activation of more expensive balancing resources. On the other hand, if there is no specific market for balancing energy, more expensive conventional generators would be activated in real-time. Notice that the latter arrangement, i.e. **joint procurement** of balancing capacity and balancing energy would result not only in **higher balancing costs** but also in **lower integration of renewable generation** since, due to the upward activation of conventional generation, not previously foreseen additional renewable production would have to be curtailed.

Another disadvantage of the joint procurement of balancing capacity and energy products is that it could limit up to a great extent the harmonization of balancing markets across borders and, consequently, prevent cross-border trading. This can be explained by the fact that **flexibility in balancing capacity markets is much more limited than flexibility in balancing energy markets**: while balancing energy is used to manage imbalances between generation and demand in real-time, balancing capacity is procured to guarantee security of supply in longer time frames. Consequently, arrangements for the procurement of balancing capacity may vary significantly depending on power systems' structural characteristics and security of supply needs. In fact, the Balancing Guideline, approved in March 2017 by European Member States[22], gives much more freedom to SOs when designing balancing capacity products in comparison to balancing energy products.

Regarding **upward and downward balancing capacity products**, joint procurement can limit competition and efficiency in balancing markets. First, the provision of upward balancing capacity by suppliers such as intermittent renewable generators does not always make economic sense since they would have to curtail part of its production to provide this product. Therefore, the requirement that both upward and downward balancing capacities must be supplied by a single BSP may limit the provision of downward balancing capacity by renewable generators. Furthermore, when upward and downward balancing capacity is jointly procured, the market marginal price is set by the marginal cost of the most expensive product.

For **example**, over a valley hour with significant intermittent renewable production, the cost for a thermal generator to provide downward balancing capacity can be significantly high, given the fact that it would have to produce close to their minimum operation output (due to limited thermal gap). Furthermore, it would receive a low market price for its production. If this generator is the marginal supplier in the joint balancing capacity market, it will set simultaneously the price of upward and downward capacities.

For these reasons, in systems with significant penetration of renewable generation, **separated markets** for the procurement of balancing capacity and balancing energy and for the

[22] https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/Pages/default.aspx

procurement of upward and downward balancing capacity will **lead to higher competition and increase efficiency in balancing markets**.

### 4.1.2. **Market gate-closure**

Due to the fact that balancing capacity is procured by SOs in order to ensure that operational security is continuously guaranteed and most power systems rely, at some extent, on inflexible generation capacity for which operation decisions have to be taken at least several hours ahead of real-time, balancing capacity is typically procured far-ahead of real-time. Gate-closures should be defined in such a way that market liquidity and efficiency are maximized without compromising system security.

In general, **gate-closures closer to real-time increase market efficiency** since the required volume of balancing products is typically reduced due to better production and consumption forecasts. Furthermore, competition among BSPs is increased since gate-closures closer to delivery facilitate the entrance of renewable generators and other potential BSPs. For this reason, in power systems with significant penetration of intermittent renewable generation, balancing products, in particular balancing energy, should be procured, as much as possible, close to real-time.

### 4.1.3. **Pricing of balancing products**

As explained in Section 2.3.1.3, the price of balancing products can be based either on pay-as-bid or marginal pricing. In general, pay-as-bid pricing imposes a barrier to the entrance of smaller players since market parties tend to submit bids as close as possible to the expected marginal price, which is a disadvantage for those agents that do not have the same possibilities to forecast prices. Furthermore, marginal prices provide adequate signals for market parties to invest in and offer balancing capabilities to the market.

Another relevant arrangement related to (the lack of) flexibility in balancing markets is the existence of **price limits** – i.e. imposition of minimum/maximum price levels – which may prevent balancing energy prices from reflecting balancing costs under certain system operation conditions. For instance, **negative prices** reflect system conditions during off-peak hours when the cost of downward balancing energy provision incurred by thermal power plants operating very close to their minimum output values can be very high, in particular under high penetration of renewable generation. In countries such as Spain, Portugal and Italy a **price floor** of 0 €/MWh is imposed. In this case, if, for example, in a certain hour two thermal generators A and B face downward balancing energy provision marginal costs of -1 €/MWh and -100 €/MWh, respectively, and remaining system downward reserve is exhausted, the SO would activate downward balancing energy from these two generators pro-rata. This is a clearly inefficient solution since generator A faces much lower provision cost than generator B. It is worth mentioning that over the period 2014-2016, downward mFRR balancing energy price in Spain was equal to 0 €/MWh in 30% of the hours during which it was activated by the SO.

The existence of negative prices provides incentives for alternative sources of balancing, such as renewable production curtailment, demand-side management and storage applications. In turn, higher competition among service providers leads to price reduction (in the case of downward balancing, to higher balancing prices). In this respect, although **price caps** are, in general, much more flexible than price floors, they should also be avoided or be set at least at the value of lost load. In summary, balancing energy **price limits** should be avoided or set in such a way that they **reflect the real-time value of electricity and drive investments** towards flexible balancing resources, including renewable generators, demand-response and storage.

In this section, arrangements leading to higher competition and efficiency in balancing markets were briefly discussed from a theoretical point of view. In the following ones, the Spanish balancing market design and its outcomes will be analyzed in detail since similar arrangements can be found in other European countries. Furthermore, Spain has experienced significant penetration of renewable generation over the past decade. Regulation in this country has evolved to adapt to this new context and, currently, wind power producers are actively participating in balancing markets. For these reasons, lessons from the Spanish case can be relevant for European policy makers currently discussing the model to be followed by the future European Balancing Market.

## 4.2. European balancing markets: a closer look into the Spanish design

As previously discussed, national European balancing market designs present significant differences. This section briefly compares arrangements found in selected countries, as they represent the most relevant designs currently applied in Europe. After that, Spanish arrangements are further described as the basis for the analyses to be carried out in Section 4.3.

Table 4.1 and Table 4.2 present the main arrangements for the procurement of aFRR and mFRR in Spain, France, the Netherlands, Germany and Denmark. It is worth mentioning that the use of RR is not mandatory in Europe. In this respect, RR is used in countries such as Portugal, Spain, France and Italy while it is not used in Germany, the Netherlands and the Nordic countries.

**Table 4.1: European market arrangements for the procurement of aFRR**

| | **Products** | **Gate-closure capacity** | **Gate-closure Energy** | **Capacity settlement** | **Energy settlement** | **Activation rule** |
|---|---|---|---|---|---|---|
| **ES** | Capacity only | Up to several hours ahead of delivery (daily) | Same as for capacity | Marginal price | Marginal price from RR bid ladder | Pro-rata |
| **FR** | Capacity only (mandatory provision) | Up to several months ahead (yearly) | Same as for capacity | Regulated price | Regulated price | Pro-rata |
| **NL** | Capacity & energy separately | Up to several months ahead (yearly) | Up to one hour ahead | Pay-as bid (capacity market) | Marginal price (activation market) | Merit order |
| **DE** | Capacity only (together with energy price bids) | Up to several days ahead (weekly) | Same as for capacity | Pay-as bid (capacity price) | Pay-as-bid (energy price) | Merit order |
| **DK** | Capacity only | Up to several days ahead (monthly) | Same as for capacity | Pay-as bid (capacity price) | DA marginal price +/- 100 DKK | Pro-rata |

It can be observed in Table 4.1 that in most of the investigated countries – Spain, France, Germany and Denmark – only BSPs with a contract for the provision of aFRR balancing capacity provide aFRR energy (i.e. there is no specific mechanism for the procurement of this product. Furthermore, in Spain and Denmark, upward and downward balancing capacities are jointly procured. In some countries such as Germany, providers present price bids for aFRR energy. In this case, aFRR is activated according to merit order, while in systems where there is no specific market for the activation of aFRR BSPs are activated on a pro-rata basis. In the latter case, the price of aFRR balancing energy is either based on other market's price, like in Spain and Denmark, or regulated, like in France. It is worth pointing out that in France, aFRR is a mandatory service for conventional generators with a regulated remuneration. Further participation (e.g. demand) is allowed through bilateral contracts with primary providers.

**Table 4.2: European market arrangements for the procurement of mFRR**

| | Product | Gate-closure capacity | Gate-closure Energy | Capacity settlement | Energy settlement | Activation rule |
|---|---|---|---|---|---|---|
| **ES** | Energy | - | Up to one hour ahead | - | Marginal price | Merit order |
| **FR** | Capacity & energy separately | Up to several months ahead (yearly) | Up to one hour ahead | Marginal price (capacity market) | Pay-as bid (energy price) | Merit order |
| **NL** | Capacity & energy separately | Up to several months ahead (yearly) | Up to one hour ahead | Pay-as bid (capacity market) | Marginal price (activation market) | Merit order (first additional bids) |
| **DE** | Capacity (bids for energy prices) | Up to several hours ahead of delivery (daily) | Same as for capacity | Pay-as bid (capacity price) | Pay-as bid (energy price) | Merit order |
| **DK** | Capacity & energy separately | Up to several hours ahead of delivery (daily) | Up to 45 minutes ahead | Marginal price (capacity market) | Marginal price (energy market) | Merit order |

In all those markets where balancing capacity and balancing energy are jointly procured, gate-closures are established, at least, several hours ahead of real-time. In the Netherlands, however, BSPs which do not have a contract for the provision of balancing capacity are allowed to provide to participate, closer to real-time, in the activation (or balancing energy) market.

Regarding markets for mFRR, it can be observed in Table 4.2 that, although in Germany mFRR balancing capacity and balancing energy are jointly procured in most cases, different markets exist for the procurement of balancing capacity and balancing energy. It is also worth noticing that in countries such Germany and France balancing energy is settled according to pay-as-bid pricing.

As for the price of (aFRR, mFRR and RR) balancing energy, among the selected countries, only Spain does not allow for negative prices although, as previously mentioned, price floors in Italy and Portugal are also established at 0 €/MWh.

In respect to the design of the future European balancing market, the **Guideline on Electricity Balancing** establishes the following: i) the **gate-closure for balancing energy** products from FRR and RR should be after the intraday gate-closure time, which, according to the Guideline on Capacity Allocation and Congestion Management is established in one hour before delivery; ii) **upward and downward balancing capacity** should be procured separately. In this regard, SOs may request an exemption from this requirement to the respective Regulatory Authority; iii) although there is no specific rule for the elimination of **price limits** in the Guideline, it is established that in case SOs identify that technical price limits are needed for efficient functioning of the market, they may jointly develop a proposal for harmonized maximum and minimum balancing energy prices.

In summary, current European balancing market arrangements may vary significantly from one country to another, in particular those regarding aFRR products. Furthermore, although the Guideline on Electricity Balancing establishes the principles for the procurement of balancing products, it is still not clear how the future European market design will look like, especially taking into account the uncertainty regarding the interpretation and transposition of the final European regulation into national grid codes. The following sections describe and analyze market arrangements in Spain with the objective of enlightening the discussion on the future design of European balancing market.

### 4.2.1. The Automatic Frequency Restoration Reserve market

The automatic Frequency Restoration Reserve (**aFRR**) market is regulated by the Operation procedure 7.2 of the Spanish SO (Spanish Government, 2015a). In Spain, aFRR is provided exclusively by **regulation areas**, which can be defined as balancing portfolios for generation units that comply with the technical requirements for the provision of aFRR (see Table 3.15). As mentioned in Section 3.2.2, regulation areas do not represent specific geographical areas. It is also worth mentioning that generation units that do not comply with the technical requirements for the provision of aFRR can be included in regulations areas for balancing purposes as long as other units that provide aFRR are also incorporated within the same area.

As previously explained, each regulation area is assigned to a single BRP (typically, the generation company owning the units within the area). Another requirement for the constitution of a regulation area is that the aggregated installed capacity of all units within the area is equal or higher than 300 MW.

Regarding the aFRR market, the Spanish SO buys once a day for the coming day of operation upward and downward aFRR capacity as a **single product** (referred in Spain as aFRR regulation band). Qualified generation units integrated in a regulation area submit individual bids of regulation band (in MW) and the corresponding price (in €/MW). Although single units may offer only upward or downward balancing capacity, the relation between total upward and downward aFRR capacities offered by each regulation area must be equal to the relation between total upward and downward capacities required by the SO for each hour. For instance if the SO requires 700 MW of upward capacity and 500 MW of downward capacity, the aggregated offer of each regulation area must comply with the ratio 7/5.

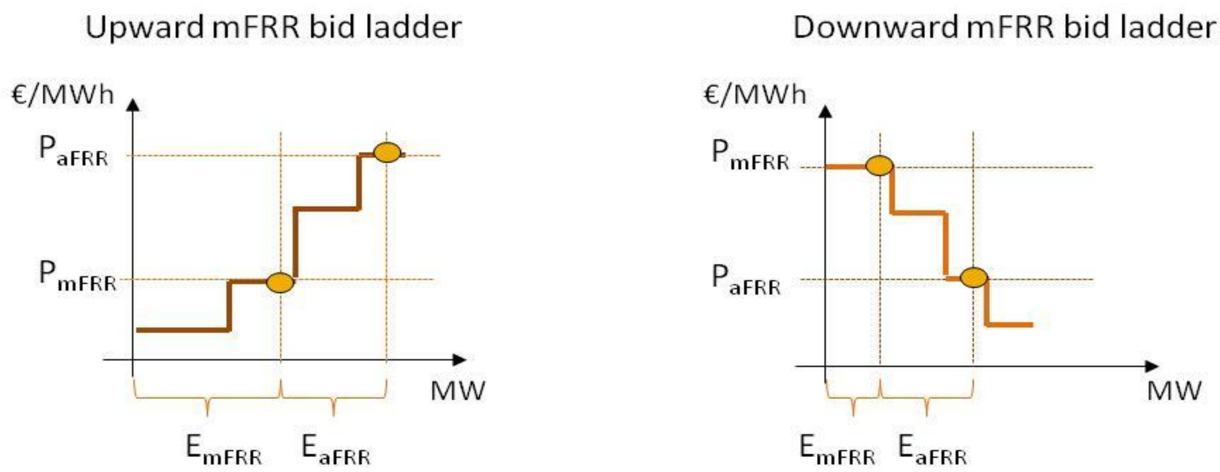



**Figure 4.1: Pricing of aFRR energy**

The cheapest bids that satisfy the total reserve required by the SO are accepted. Those generators whose offers are accepted receive the aFRR regulation band marginal price (capacity term in €/MW). Notice that in case the regulation area does not comply with the committed aFRR capacity, it has to pay a penalization equal to 150% the aFRR market price per MW of non-available capacity.

In real-time, aFRR is **activated on a pro-rata basis**, i.e. in proportion to the aFRR capacity assigned to each regulation area. As mentioned in Section 3.2.1, the marginal price of aFRR upward/downward energy (in €/MWh) is determined by the upward/downward mFRR market bid ladder, taking into account the aFRR deployed beyond the activated mFRR, as represented in Figure 4.1. In this respect, as previously explained negative prices are not allowed in Spain.

### 4.2.2. **The Manual Frequency Restoration Reserve market**

The manual Frequency Restoration Reserve (**mFRR**) market is regulated by the Operation Procedure 7.3 of Spanish SO (Spanish Government, 2015b). In Spain, mFRR is provided by qualified generation and pumped storage consumption units. All qualified units are required to declare their whole available **upward and downward mFRR capacities** to the SO before the gate-closure for mandatory offers, i.e. before 11pm of the day before the operation day (D-1). Together with the available capacities (in MW) units submit the upward and downward energy prices (in €/MWh) in case mFRR is activated in real-time by the SO. Notice that mFRR **capacity is not remunerated**.

During the day of operation, information regarding **capacity availability can be updated until one hour before real-time** in case the previously declared capacity is committed in other markets. In this respect, it is worth mentioning that, before the creation of the common market for cross-border exchange of mFRR energy by the Portuguese, Spanish and French SOs[23], mFRR bids could be updated until 25 minutes before real-time. This gate-closure time still applies to those hours when there is no cross-border exchange of mFRR energy.

During operation the SO activates the cheapest (i.e. lowest price) upward energy bids and/or the cheapest (i.e. highest price) downward energy bids. The hourly marginal price for upward/downward mFRR energy is set by the most expensive (highest price in case of upward energy and lowest price in case of downward energy) activated bid.

[23]Regulated by Operation Procedures 7.3 and 14.6 of the Spanish SO. Available at: http://www.ree.es/en/activities/operation-of-the-electricity-system/operating-procedures

As it will be discussed in Section 4.3, in December 2015 the Spanish SO updated its grid codes related to electricity balancing in order to adapt balancing markets to the participation of intermittent renewable production. One of the introduced modifications is the financial **penalization for non-compliance with mFRR allocation** by the SO. Notice that, before this modification, deviations from mFRR schedules (represented by the component $OS_{gu.h}$ in Equation 4.1) were settled at the imbalance price as any other energy imbalance. According to the new grid code, compliance with upward and downward mFRR allocation by the SO is penalized according to Equations 4.1 and 4.2 respectively, where $PO_{BSP,h}^{eMFRR}$represents the hourly payment obligation for mFRR schedule deviations allocated to the BSP; $OS_{BSP,h}^{eMFRR}$ represents the allocation of mFRR by the SO to the BSP; $eMFRR_{BSP,h}$ represents the mFRR energy actually provided by the BSP; $P_h^{eMFRR}$ is the hourly marginal price of mFRR balancing energy and $P_h^{DA}$ is the hourly day-ahead marginal price.

$$PO_{BSP,h}^{eMFRRup} = \left(OS_{BSP,h}^{eMFRRup} - eMFRR_{BSP,h}^{up}\right) \times P_h^{eMFRR,up} \times 1.2 \qquad (4.1)$$

$$PO_{BSP,h}^{eMFRRdw} = \left(OS_{BSP,h}^{eMFRRdw} - eMFRR_{BSP,h}^{dw}\right) \times P_h^{DA} \qquad (4.2)$$

### 4.2.3. **The Replacement Reserve energy market**

The Replacement Reserve energy (**RRe**) market is regulated by the Operation Procedure 3.3 of the Spanish SO (Spanish Government, 2015c). This market deals with energy imbalances that may occur after the gate-closure of an intraday market auction until the beginning of the delivery horizon of the following auction. As explained in Section 2.1.1, the Spanish intraday market is organized as seven centralized auctions with different gate-closure times (lead-times vary between 3.25 and 7.25 hours, depending on the delivery hour) and different energy delivery horizons. The RRe market is only called by the SO if the expected **hourly deviation** during one or more hours within the delivery horizon of the market (shown in Table 4.3) **is equal or greater than 300 MW**.

This reserve could be compared to the mFRR in the sense that the maximum response time required for the provision of RR is 15 minutes for the first hour of the delivery horizon. Nevertheless, while mFRR may be activated within the operation hour and is typically deployed for some minutes (and up to one hour), RR is activated before the delivery horizon and it is deployed for at least one hour (and up to four hours). In this sense, the RRe market functions in a **similar way as the intraday market**: units committed in the RRe market comply with (new) hourly energy schedules (during one or more hours within the delivery horizon of the market) whenever the SO requests upward or downward RR energy.

Table 4.3 presents the time schedule of each auction of the intraday market and the delivery horizons of the intraday and RRe markets. After the intraday congestion management procedure and as soon as potential imbalances are identified, the SO calls the RRe market. Qualified generation and pumped storage units willing to participate in the RRe market are requested to submit energy bids (in MWh) and corresponding prices (in €/MWh) within 30 minutes after the announcement of upward or downward RR energy requirements for a certain delivery horizon.

**Table 4.3: Gate-closures and delivery horizons corresponding to intraday (ID) and RRe auctions**

| | ID1 | ID2 | ID3 | ID4 | ID5 | ID6 | ID7 |
|---|---|---|---|---|---|---|---|
| ID gate-closure time | 18:45 (D-1) | 21:45 (D-1) | 1:45 (D) | 4:45 (D) | 8:45 (D) | 12:45 (D) | 18:45 (D) |
| ID market matching | 19:30 | 22:30 | 2:30 | 5:30 | 9:30 | 13:30 | 19:30 |
| ID congestion management | 20:00 | 23:00 | 3:00 | 6:00 | 10:00 | 14:00 | 20:00 |
| Final ID schedule publication | 20:20 | 23:20 | 3:20 | 6:20 | 10:20 | 14:20 | 20:20 |
| ID delivery horizon (hours) | 1-24 | 5-24 | 1-24 | 8-24 | 12-24 | 16-24 | 22-24 |
| RRe delivery horizon (hours) | 1-4 | 5-7 | 8-11 | 12-15 | 16-18 | 19-21 | 22-24 |

Since December 2015, non-compliance with upward and downward RR energy allocation by the SO also leads to **financial penalties**, which are calculated according to Equations 4.3 and 4.4, respectively.

$$PO_{BSP,h}^{eRRup} = \left(OS_{BSP,h}^{eRRup} - eRR_{BSP,h}^{up}\right) \times P_h^{eRR,up} \times 1.2 \tag{4.3}$$

$$PO_{BSP,h}^{eRRdw} = \left(OS_{BSP,h}^{eRRdw} - eRR_{BSP,h}^{dw}\right) \times P_h^{DA} \tag{4.4}$$

### 4.2.4. **The Replacement Reserve capacity market**

The Replacement Reserve capacity (**RRc**) market is regulated by the Operation Procedure 3.9 of the Spanish SO (Spanish Government, 2013a) and it is used by the Spanish SO for the procurement of upward RR capacity. Before the creation of the RRc market in May 2012, there was no specific mechanism to guarantee RR capacity provision. In that case, if available upward RR capacity resulting from the DA market schedule was below the RR reference level (i.e. sufficient enough to compensate deviations between demand and renewable production market schedules and respective SO forecasts) the SO would redispatch thermal generators through the congestion management procedure[24].

Due to the increasing integration of renewable generation in the electricity market and, consequently, the growing need to redispatch thermal units for balancing purposes, the Spanish SO started procuring upward RR capacity through the RRc market. Accordingly, the RRc market is only called when available upward RR capacity resulting from the day-ahead market schedule is lower than the corresponding reference level.

In order to assess the need for calling the RRc market, once the SO receives the day-ahead market schedules disaggregated for the different generation and consumption units, it verifies: a) the additional hydro production that could be maintained for a period of 4 consecutive hours; (b) the available upward reserve capacity that could be provided by connected coal, combined cycle, and pumped storage units; and (c) the total upward capacity available in offline fast-start gas-fired power plants. Finally, aFRR requirements are deducted from this amount. In case the available (upward) capacity is lower than RR requirements, the SO calls the RRc market.

Only thermal units not committed in the day-ahead market are allowed to present bids to the RRc market. It is important to notice that, in practice, the RRc market has only separated the

[24] A detailed description of the redispatch of thermal generators for balancing purposes is provided by Gil et al. (2010).

dispatch of thermal units for balancing purposes from the dispatch of thermal units for congestion management purposes.

In the following section, empirical analyses based on data published by the Spanish SO is used to identify relevant barriers imposed by market arrangements described here to the participation of renewable generators in active balancing. As already explained, the Spanish case is an interesting example due to the significant penetration of intermittent renewable generation together with an advanced regulatory framework in what respects the participation of these producers in balancing markets.

## 4.3. Participation of renewable generators in active balancing

In Spain, where more than 20% of the total electricity demand is supplied by wind generators, the government recently launched a reform that eliminated previous support schemes for renewable production (i.e. feed-in tariffs and feed-in premium) and linked the remuneration of renewable producers directly to their participation in the electricity market (Spanish Government, 2013b). According to the new scheme, apart from revenues obtained in the market, a specific remuneration is given to those installations which during their useful lifetime cannot recover their whole investment and operation costs through market participation only. This specific remuneration is mainly based on the difference between standard investment and operation costs, which is calculated for each type of renewable installation, and estimated market revenues, calculated as the total energy production sold at the day-ahead market price (Spanish Government, 2014). As of the beginning of 2017, 6 GW of wind generation were entitled to no specific remuneration.

The reform also granted intermittent renewable producers the possibility of participating in balancing markets, provided that units comply with the technical requirements established by the Spanish SO for the provision of balancing services. In this respect, in December 2015 the Spanish SO updated its grid codes related to balancing arrangements in order to adapt them to the new **regulatory framework for renewable generators**. Notice that the new regulatory scheme provides strong incentives to renewable producers to maximize their benefits through an active participation in electricity markets, including balancing mechanisms.

In the beginning of 2016 the first wind generators started the qualification procedures in order to become BSPs in Spain and since April 2016 they have been providing mFRR and RR energy, although this participation is still limited: while wind energy accounted for 16% of the total electricity production in Spain from April to December 2016, wind generators only provided 5% of downward mFRR energy and 1% of upward mFRR energy. In the case of RR, wind energy participation is still very low: 0.7% of total upward RR energy provision and 0.4% total downward RR energy provision in the same period. One year later (March 2017), 6 GW of wind production is qualified to participate in mFRR and RRe markets, according to data from the Spanish SO. As of today, there are no intermittent renewable units integrated in regulation areas.

In this respect, barriers to the participation of renewable producers in balancing markets are typically associated to the intrinsic characteristics of intermittent generation such as high variability and limited predictability together with the existence of market arrangements that have been designed based on the characteristics of traditional suppliers of balancing services. Flexible market arrangements, on the other hand, can contribute to the participation of renewable generators and other potential providers, such as demand response, in balancing markets.

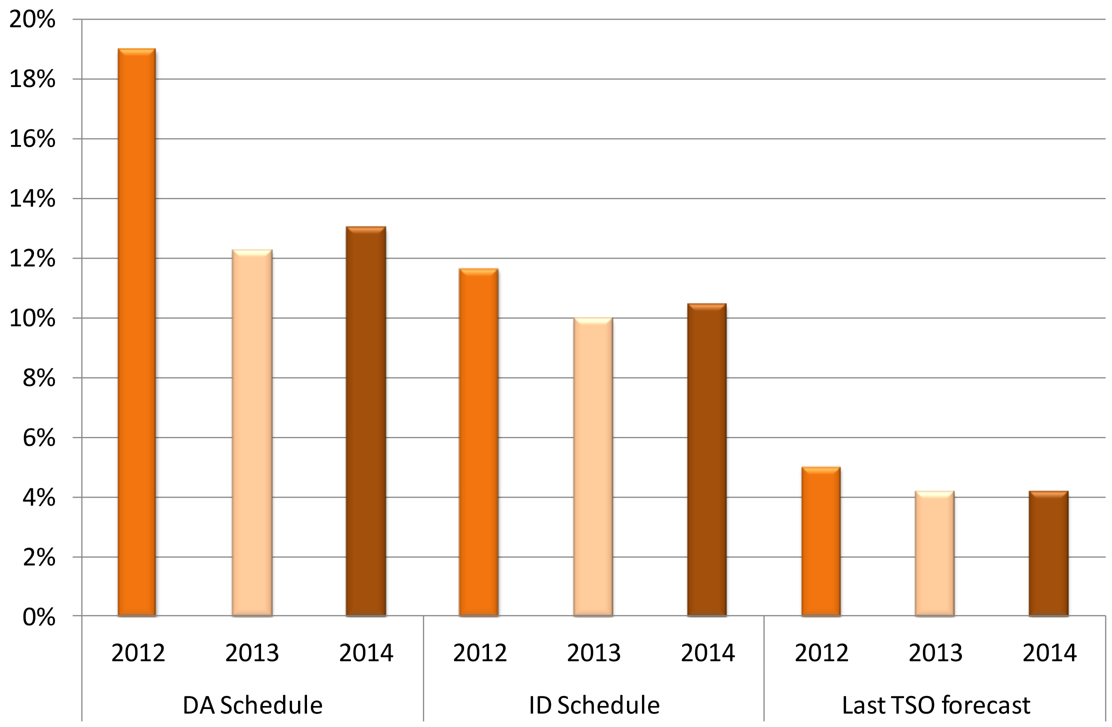



**Figure 4.2: Aggregated wind production average deviations with respect to the day-ahead and intraday market schedules and to the most updated production forecast generated by the Spanish SO**

Figure 4.2 shows aggregated wind production average deviations in respect to day-ahead and intraday market hourly schedules and to the most updated hourly production forecast (last SO forecast) published by the SO 20 minutes before real-time[25]. Deviations are computed as the difference between actual hourly generation and the scheduled/forecasted hourly production. Percent values are calculated based on the intraday market schedule or the SO forecast. Notice that market schedules and SO forecasts are used as an approximation of the aggregation of individual wind producers' forecasts[26]. Based on the data shown in Figure 4.2, it can be concluded that intermittent renewable production forecast errors can be decreased significantly from the intraday timeframe until some minutes before real-time operation.

**Table 4.4: Maximum hourly positive and negative deviations with respect to the intraday market schedule and to the last SO forecast for different wind capacity factor levels**

| Hourly wind capacity factor | Capacity factor hours (% number of hours) | | | Market schedule/SO forecast | Maximum positive deviation | | | Maximum negative deviation | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | | 2012 | 2013 | 2014 | 2012 | 2013 | 2014 |
| **< 20%** | 46% | 37% | 43% | ID market | 169% | 95% | 120% | 88% | 69% | 76% |
| | | | | Forecast | 85% | 235% | 55% | 64% | 58% | 54% |
| **≥ 20%** | 54% | 63% | 57% | ID market | 52% | 44% | 33% | 33% | 39% | 34% |
| | | | | Forecast | 42% | 36% | 28% | 24% | 40% | 21% |
| **≥ 30%** | 29% | 39% | 33% | ID market | 35% | 29% | 31% | 28% | 35% | 34% |
| | | | | Forecast | 22% | 26% | 25% | 15% | 40% | 21% |
| **≥ 40%** | 14% | 21% | 17% | ID market | 26% | 20% | 24% | 19% | 30% | 29% |
| | | | | Forecast | 22% | 17% | 18% | 12% | 14% | 21% |

Table 4.4 presents maximum positive and negative hourly deviations with respect to the intraday market schedule and to the last SO forecast for different wind capacity factors. The hourly capacity factor is calculated as the hourly production divided by the total installed capacity. In

[25]Day-ahead and intraday market schedules correspond to the sum of individual wind producers' sells (and purchases) in day-ahead and intraday markets. The most updated (publicly available) forecast corresponds to the aggregated national production forecasted by the SO's wind power prediction tool (SIPREÓLICO), which takes into account data from all wind farms. This tool is used by the SO to dimension DA reserve requirements and real-time balancing needs (González et al., 2004).
[26]Market schedules can be influenced by strategies adopted by the different agents in the market and, consequently, cannot be directly considered as actual production forecasts. In respect to the SO forecast, in general, wind producers are equipped with more advanced forecasting tools and have better information regarding production in their wind farms. Therefore, their forecasts could be more accurate than the ones generated by the SO.

general, percent deviations decrease for higher capacity factor levels. Maximum levels of production forecast errors associated with different gate-closure times can be a relevant factor when considering the participation of intermittent generators in balancing markets.

According to the data presented in Table 4.4, in general, percent deviation values decrease for higher wind capacity factors. It can also be observed that maximum deviation values are significantly higher for wind capacity factors lower than 20%. Based on these values, it is unlikely that intermittent producers participate in balancing markets when production levels are below actual average wind capacity factor (in 2012, 2013 and 2014, average wind capacity factor levels in Spain were 24%, 27% and 25%, respectively).

### 4.3.1. **Considerations regarding the participation in the aFRR market**

As explained in Section 4.2.1, one of the requirements for the constitution of a regulation area is that the aggregated installed capacity of all units within the area is equal or higher than 300 MW. Consequently, the participation of generation units belonging to small renewable generation companies (i.e. total installed capacity lower than 300 MW) in aFRR provision would require either the inclusion of these generation units into a third-party regulation area (which depends on the approval of the affected regulation area) or the allocation of balance responsibility to a third-party aggregator.

Even though a group of intermittent renewable units complies with the criteria for the constitution of a regulation area, the condition establishing that the relation between total upward and downward aFRR capacities offered by each regulation area must be equal to the relation between total upward and downward capacities required by the SO for each hour may hinder or limit the participation of regulation areas composed exclusively by intermittent renewable units. This can be explained by the fact that, in order to provide upward aFRR capacity, renewable units would have to produce below its maximum (potential) production level according to primary resource (e.g. wind) availability. This means that, in order to provide upward aFRR capacity, a renewable producer would incur an opportunity cost which corresponds to the revenue that this producer could obtain from selling the “curtailed” power in the day-ahead (or intraday) market.

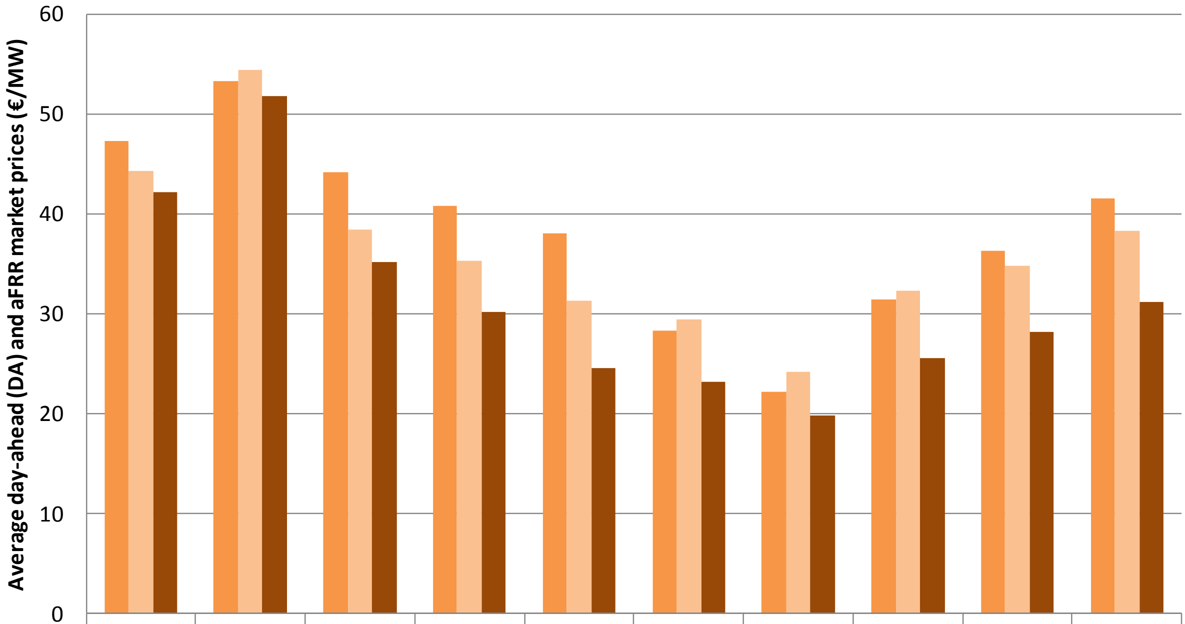
Levels of wind curtailment required for the participation of wind generators in the Spanish aFRR market were estimated under the Twenties Project framework. The study was performed by the Spanish generation company Iberdrola for the aggregation of its wind power plants in Spain

(≈ 5.3 GW). According to the analysis, wind curtailment could vary between 19% and 33% of the total installed capacity, considering forecast error levels corresponding to market lead-times of 15 and 75 minutes, respectively (García-González, 2013). Wind production variability within a time resolution of 15 minutes (aFRR deployment time) was also considered in the study. Notice that the above mentioned curtailment levels are comparable to maximum negative hourly deviation values with respect to the intraday market schedule and to the SO forecast for wind capacity factor equal or higher than 20% (see Table 4.4).

It is worth pointing out that the aFRR market has much longer lead-times (varying from 7.5 to 30.5 hours, depending on the delivery hour) than the gate-closures considered in the above-mentioned study. Furthermore, renewable production variability within one hour (product time-resolution of the Spanish balancing markets) is typically higher than variability within a time resolution of 15 minutes. In this respect, Nazir and Bouffard (2012) reported that intra-hour variability of wind production can be significantly higher when compared to variability within timeframes lower than 30 minutes. This means that curtailment levels required for the participation of wind producers in the Spanish aFRR market could be much higher than the ones estimated in the study.

Under current arrangements, the participation of intermittent generators in the Spanish aFRR market would greatly depend on the spread between aFRR capacity and day-ahead market prices, which should compensate for the opportunity cost of curtailing renewable production that could be sold in the day-ahead (or intraday) market instead. Figure 4.3 presents yearly average day-ahead and aFRR market prices and average day-ahead and intraday market prices under different levels of hourly wind capacity factor (for instance, the second column shows the day-ahead market prices during the hours in which the wind capacity factor is lower than 20%).

The figure clearly shows the influence of wind production on market prices: for higher levels of wind production, day-ahead market prices decrease while aFRR market prices increase. The latter is mainly associated to the higher cost of downward balancing capacity provision by thermal units when wind production levels are high, in particular during off-peak hours when thermal power plants are operating at levels very close to their minimum output values (García-González, 2013).




| | DA | DA (cf<20%) | DA (cf≥20%) | DA (cf≥30%) | DA (cf≥40%) | aFRR | aFRR (cf<20%) | aFRR (cf≥20%) | aFRR (cf≥30%) | aFRR (cf≥40%) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2012 | 47 | 53 | 44 | 41 | 38 | 28 | 22 | 31 | 36 | 42 |
| 2013 | 44 | 54 | 38 | 35 | 31 | 29 | 24 | 32 | 35 | 38 |
| 2014 | 42 | 52 | 35 | 30 | 25 | 23 | 20 | 26 | 28 | 31 |

**Figure 4.3: Yearly average day-ahead and aFRR market prices under different wind capacity factor levels**

Table 4.5 shows the maximum and average hourly differences between aFRR and day-ahead market prices for hours during which aFRR market prices are higher than day-ahead prices for different levels of wind capacity factor. It can be noticed that the lowest price differences correspond to a wind capacity factor lower than 20%. Given the influence of wind production on market prices and the fact that forecast errors increase for lower wind production levels, it is reasonable to assume that only under very specific circumstances it will be profitable for wind generators to participate in the aFRR market, and consequently on aFRR provision, when wind capacity factor is below 20%. Based on these data and considering price differences only, participation of wind generators in the aFRR market could be profitable during approximately 20% of the hours within a year (i.e. average percent number of hours when aFRR prices are higher than day-ahead prices and wind capacity factor is equal or higher than 20%). Nevertheless, if curtailment requirements are taken into account, participation of wind generators in the aFRR could be limited to an even lower number of hours.

An alternative market arrangement which could facilitate the participation of intermittent renewable producers in balancing markets is the separation of balancing capacity and balancing energy products, as discussed in Section 4.1.1. The separation of balancing capacity and balancing energy products allows the establishment of shorter gate-closure times for balancing energy bids, fostering the participation of intermittent renewable producers in electricity balancing. For instance, in the Netherlands, where this design is implemented, the gate-closure for balancing energy bids is one hour before real-time.

**Table 4.5: Day-ahead and aFRR hourly market price differences**

| | Wind capacity factor | < 20% | ≥ 20% | ≥ 30% | ≥ 40% |
|---|---|---|---|---|---|
| **2012** | Max. price difference when aFRR price > DA price | 48 | 180 | 180 | 180 |
| | Average price difference when aFRR price > DA price | 13 | 31 | 35 | 42 |
| | % number of hours when aFRR price > DA price | 1% | 16% | 13% | 7% |
| **2013** | Max. price difference when aFRR price > DA price | 139 | 237 | 197 | 181 |
| | Average price difference when aFRR price > DA price | 28 | 32 | 35 | 39 |
| | % number of hours when aFRR price > DA price | 2% | 22% | 17% | 11% |
| **2014** | Max. price difference when aFRR price > DA price | 50 | 136 | 136 | 136 |
| | Average price difference when aFRR price > DA price | 12 | 25 | 27 | 28 |
| | % number of hours when aFRR price > DA price | 2% | 19% | 15% | 10% |

Apart from this, the separation of upward and downward balancing capacity products (as implemented in countries such as Belgium, Germany and the Netherlands) could facilitate the participation of intermittent renewable generators in balancing capacity provision. Furthermore, it is likely that this separation reduces the procurement costs of aFRR capacity, in particular in those cases where upward or downward balancing capacity margin is tight. This can be explained by the fact that, currently, the same hourly price is applied to both upward and downward contracted capacities while, depending on the operation conditions, provision costs may significantly differ from one another.

## 4.3.2. **Participation in the mFRR market**

Even before intermittent renewable units were allowed to participate in balancing markets, wind generators passively contributed to "last resort" downward mFRR energy provision. Last resort downward balancing energy provision refers to situations when available downward mFRR is exhausted and the SO curtailed renewable production through the real-time congestion management procedure in order to balance generation and demand. In this respect, it is worth pointing out that when a curtailment order was issued by the SO, curtailed units had to reach their new generation schedule within 15 minutes. This corresponds to the maximum response time for mFRR providers (see Table 3.15).

Figure 4.4 presents total annual wind production curtailed in real-time in relation to total wind feed-in. In 2012, downward mFRR was activated during more than 3,900 hours; among these, wind curtailment was required in 405 hours. In 2013 and 2014 wind curtailment was required during 33% and 16% of the hours during which downward mFRR was activated, respectively.

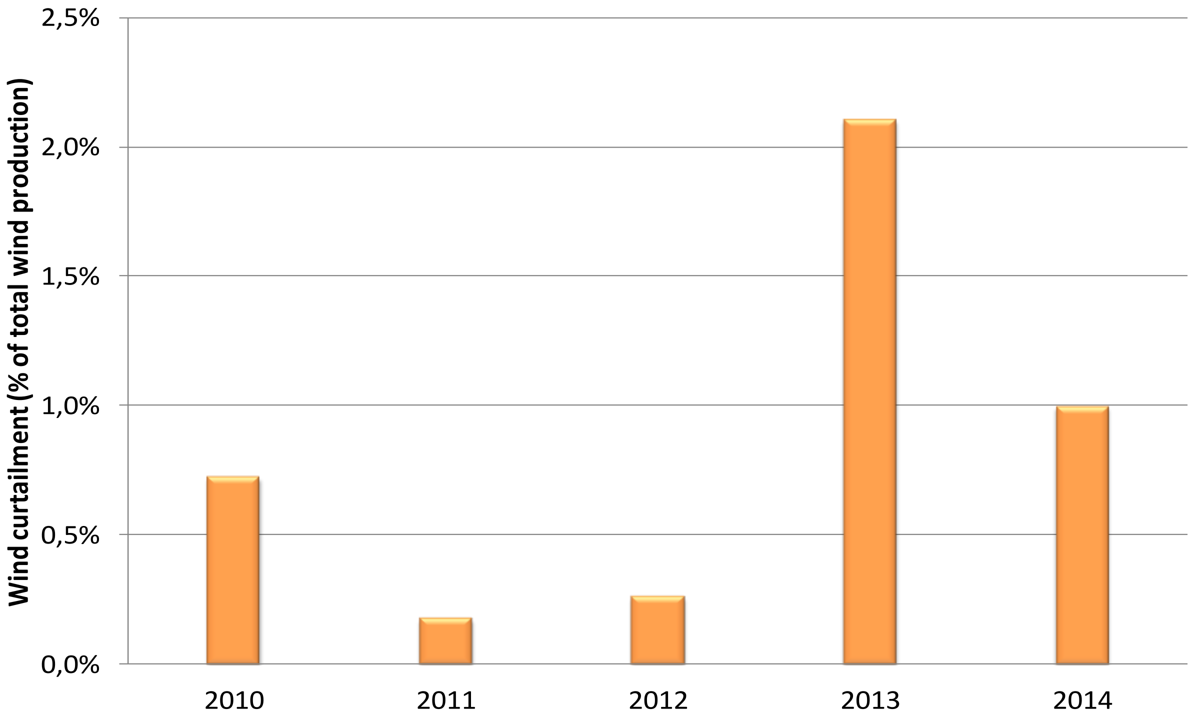



**Figure 4.4: Total yearly real-time wind production curtailment (% of total wind feed-in)**

From an economic perspective, the main difference between production curtailment for balancing purposes[27] and provision of downward mFRR is that, in the former case, renewable generators are settled at a regulated remuneration (15% of the day-ahead market price), while mFRR providers are settled at the mFRR market price. Notice that the remuneration of curtailed generators does not reflect real-time (downward) balancing costs, which are supposed to be brought forth by balancing market prices. The importance of cost-reflective prices is that they encourage potential providers of balancing services to invest in balancing capacity and provide adequate incentives to BRPs to keep their balance and/or help the system to restore its balance.

Related to this, the inexistence of negative energy prices in Spain could prevent cost-reflective prices from being achieved when, for instance, downward reserve constraints are significant (e.g. during off-peak hours with thermal units producing at their minimum production level). The inexistence of negative prices would also limit the participation of intermittent generators in downward balancing energy provision to hours when the day-ahead market price is very low or equal to zero[28].

Renewable generators can also participate in upward mFRR provision whenever maximum (potential) generation, according to updated production forecasts, is higher than the production scheduled in the intraday market. In order to estimate the potential participation of intermittent generators in upward mFRR provision in previous years, a simple exercise was carried out based on empirical data. First, hourly wind production scheduled in the intraday market was compared to hourly production forecasted by the SO. The hours during which there would be an excess of wind production in relation to the intraday market schedule (i.e. scheduled production was lower than forecasted production) were identified. Then, it was verified if actual hourly generation was equal or higher the forecasted production. Finally, it was checked whether the SO activated upward mFRR during those hours.

In 2012, 2013 and 2014, the SO activated upward mFRR energy during 3,934, 4,291, and 4,385 hours, respectively. According to the results of the analysis, wind generators could have contributed to upward mFRR provision during 799, 571 and 517 (20%, 13% and 12%) hours in

[27]It is worth pointing out that generation can also be curtailed in real-time due to transmission constraints (e.g. to avoid line overloading).
[28]This is due to the fact that downward balancing energy providers are rewarded the difference between the day-ahead (or intraday) market price and the price paid to the SO for downward energy provision. For intermittent renewable generators this could represent a loss of income since, in principle, they cannot store their primary resource.

2012, 2013 and 2014, respectively. Notice that, during those hours, wind producers have actually contributed to system balancing by deviating from their schedules in the opposite direction of the system imbalance and avoiding the activation of more expensive upward mFRR. It is worth mentioning that from April to December 2016, wind producers have provided upward mFRR energy during 30% of the hours during which the SO activated this reserve, although the total volume is still low (1% of the total upward mFRR energy used by the SO in the same period).

Among the Spanish balancing markets, the mFRR market is the one which presents fewer barriers to the participation of intermittent renewable generators and other smaller resources. This is mainly related to more flexible design aspects such as the procurement of separate upward and downward products and gate-closure closer to real-time operation. This gate-closure gives renewable generators an opportunity to update their schedules according to better production forecasts and, consequently, reduce final imbalances.

On the other hand, penalties for non-compliance with balancing energy provision schedules beyond the penalization through the imbalance settlement may discourage renewable producers and other smaller providers from participating in balancing markets. On the other hand, cost-reflective imbalance prices provide incentives for BRPs (which may also be BSPs) to support the system balance in real-time, as discussed on Chapter 3. Furthermore, the penalization for non-compliance with balancing energy allocation does not reflect the costs the SO incur to balance the system in real-time and should be not applied. Instead In case a certain provider consistently fails in delivering balancing power, the SO could disqualify this unit as a balancing service provider.

### 4.3.3. **Participation in the RRe market**

Compared to the aFRR market, the RRe market presents fewer barriers to the participation of intermittent renewable generators due to design aspects such as separated procurement of upward and downward products and gate-closures closer to real-time operation. However, if compared to the mFRR market, the RR market design limits to a greater extent the participation of intermittent renewable producers. These limitations are related earlier gate-closures with respect to energy delivery and longer deployment times (or delivery horizons) in comparison to the mFRR market. In fact, the volumes of upward and downward RR balancing energy provided by wind generators in 2016 represented 18% and 4% of the corresponding volumes of mFRR energy.

As previously mentioned, the RRe market is very similar to the intraday market. In this sense, there would be no barriers to the participation of intermittent renewable producers in this market since they already participate in the intraday market. Nevertheless, this participation would be much more limited since, while deviations from intraday market schedules are penalized through the imbalance settlement, deviations from the RRe market schedule leads to additional penalties, as explained in Section 4.2.3.

Table 4.6 presents hourly average volumes of energy traded in each session of the intraday market and volumes of RR and mFRR energy. The table shows that average volumes of RR energy deployed are, in general, similar or higher than the volumes of energy traded in the intraday market[29] and the volumes of activated mFRR.

**Table 4.6: Hourly average volumes of energy traded in the intraday market and volumes of RR and mFRR energy (MWh)**

| | 2012 | 2013 | 2014 |
|---|---|---|---|
| Intraday 1 | 3,284 | 2,042 | 1,989 |
| Intraday 2 | 863 | 681 | 585 |
| Intraday 3 | 466 | 470 | 379 |
| Intraday 4 | 378 | 380 | 324 |
| Intraday 5 | 597 | 547 | 489 |
| Intraday 6 | 869 | 786 | 723 |
| Intraday 7 | 909 | 787 | 589 |
| Upward RR energy | 1000 | 877 | 708 |
| Downward RR energy | 889 | 684 | 561 |
| Upward mFRR energy | 751 | 764 | 684 |
| Downward mFRR energy | 698 | 563 | 562 |

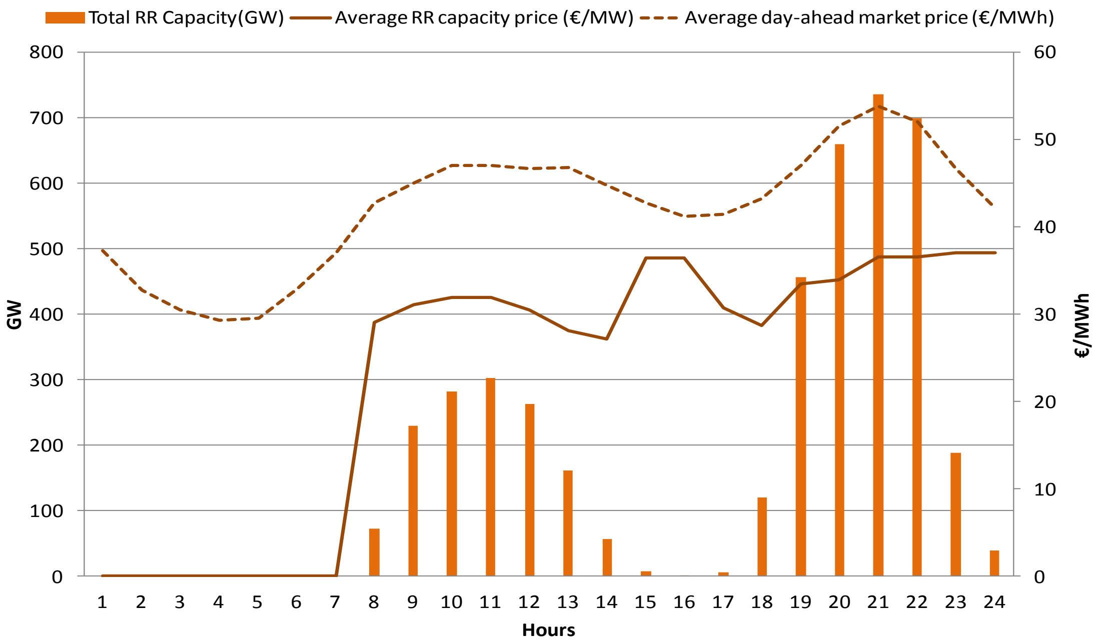
In respect to the RRe market, an alternative arrangement to facilitate a higher integration of renewable production is the replacement of this market with more intraday market sessions. In practice this means reducing the lead-times of the Spanish intraday market, which could significantly reduce the need for (more expensive) balancing resources. In case the RRe market

[29]The volume of energy traded in the first ID market session is, in general, significantly higher than the energy traded on the remaining sessions. This is discussed in detail by Chaves-Ávila and Fernandes (2014).

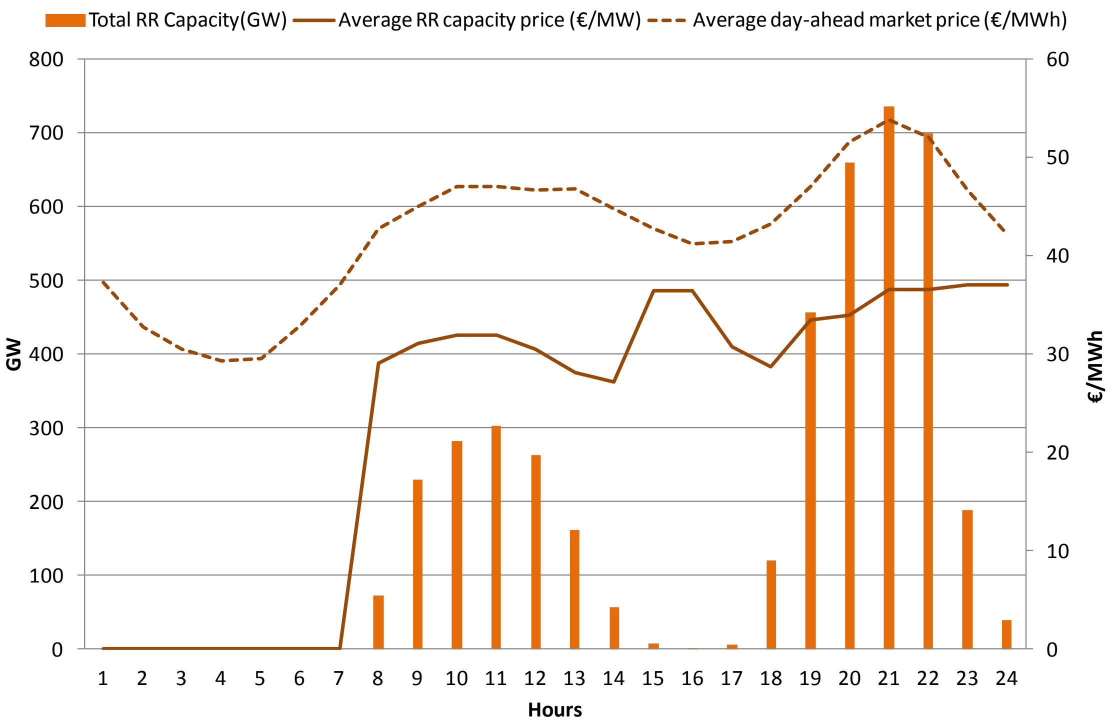
was still required for balancing purposes, lead-times of this market should be reduced in order to favor the participation all potential participants (including renewable producers), which could also contribute to the reduction of balancing costs.

### 4.3.4. **Considerations regarding the RRc market**

As explained in Section 0, only thermal units not committed in the day-ahead market schedule Figure 4.5 presents total hourly amounts of RR capacity procured in 2013 and 2014, and the corresponding hourly average day-ahead and RR capacity market prices. In 2012 (from May to December), 2013 and 2014, RR capacity was procured in 549, 1,033, and 1,225 hours respectively. Average hourly amounts of RR capacity in those years were 2,979, 2,907 and 3,493 MW, respectively. Figure 4.5, it can be observed that RR capacity is procured mostly during two time periods: from 8h until 14h and from 18h to 23h. These periods correspond to hours of high demand levels and, consequently, high day-ahead market prices. It is important to point out that the volume of RR capacity procured during the months from May to September is considerably lower when compared to the amount of RR capacity procured during the rest of months. This is also related to demand levels (demand during warmer months is typically lower than demand in colder months). It can also be observed that, in general, RR capacity prices are below day-ahead prices.




(a) 2013




(b) 2014

**Figure 4.5: Total hourly volume of procured RR capacity *versus* average day-ahead and RR capacity market prices**

These market outcomes, together with the early gate-closure for RR capacity bids (i.e. several hours ahead of real-time) it is unlikely that intermittent renewable generators would profit from participation in this market. Regardless, technology specific markets may undermine competition and favor higher market prices, which impose higher costs on the end-consumer. Therefore, the RR capacity market should be open to all potential service providers, in particular to demand response, which can significantly contribute system balancing during peak hours.

## 4.4. Conclusions

This chapter has discussed market arrangements leading to higher competition and, consequently, efficiency in balancing markets. The discussion was supported by empirical evidence from the Spanish balancing markets. Based on this study, it was concluded that the markets with gate-closures closer to real-time presents the most favorable conditions to the participation of intermittent renewable generators and other smaller agents in active balancing. However, the participation of these agents can be limited significantly limited by inflexible market arrangements. In this sense, some policy recommendations are proposed.

- First, the **separation between balancing capacity and balancing energy** products **and between upward and downward balancing capacity** is strongly recommended. Separated procurement of different balancing products could not only facilitate a higher participation of new potential providers, such as renewable producers and demand, but also increase efficiency in balancing services procurement. The latter is related to the fact that higher competition among providers enhances efficiency and that actual (provision) costs are more likely to be revealed when different products are procured separately – single (or joint) products are generally bought at the price of the product of highest cost.
- **Reducing lead-times of intraday markets** is also recommended. Intraday markets facilitates the reduction of imbalances and, consequently, balancing costs faced by the SO. In the Spanish case, reducing the intraday market lead-times could significantly reduce the activation of slower reserves (RR).
- **Technology-specific balancing markets/products**, such as the Spanish RRc market, should also be avoided: all potential providers should be allowed to participate in balancing service provision as long as technical requirements are fulfilled.
- **Price limitations should be avoided**. For instance, negative prices reflect the system conditions during super off-peak hours when the cost of downward reserve provision by thermal power plants operating very close to their minimum output values can be very high. Therefore, the inexistence of negative energy prices prevents imbalance prices from reflecting balancing costs during these situations and may provide distorted incentives to market parties.
- Finally, **penalties** for deviations from balancing energy provision schedules beyond the imbalance settlement **should be avoided** since may discourage renewable producers and other smaller providers from participating in balancing markets. Instead, the imbalance settlement should provide adequate incentives for BRPs (including BSPs) to keep the system balanced as much as possible.

# Chapter 5: Intraday market design: optimizing balancing costs through intraday trading

The objective of this chapter is to analyze intraday market design options, taking into account the proposals currently under discussion by the ENTSO-E and national/regional market operators for the European Target Model, in order to identify best practices and derive policy recommendations for an efficient integration of renewable generation in European power systems. This chapter is divided according to the following:

I. First, intraday market design options are described.
II. After that, the European intraday target model and current developments are briefly discussed.
III. Then, evidence from the Spanish and the German markets is used to propose policy recommendations.

## 5.1. Intraday market design options

Intraday markets represent a relevant opportunity for market agents to balance their portfolio by trading closer to the delivery period, taking benefit from more updated information regarding production and/or consumption. In this sense, intraday trading is a tool for lowering system costs since it contributes to the reduction of balancing actions in real-time, especially in a context with significant penetration of renewable generation (Borggrefe and Neuhoff, 2011; Weber, 2010).

As explained in Section 2.1.1, currently, the design of intraday markets is based either on discrete auctions or continuous trading in most European countries. **Continuous intraday** markets consist of a limit order book that stores incoming buy orders on the bid side and sell orders on the offer/ask side. Since continuous markets allow for 24/7 trading – and up to the gate-closure for each delivery period (typically, between 45 minutes and one hour before delivery in European continuous markets) – participants are provided with an opportunity to handle their imbalances as soon as they appear. Orders are executed as soon as the bid price equals or exceeds the ask price in a continuous way until the market gate-closure time and trades are settled according to **pay-as-bid pricing**. In this respect, during the trading period for a certain delivery period, the market equilibrium may change quite rapidly, depending on the arrival of information about intraday deviations from the day-ahead market schedules. This can make the intraday market price volatile and non-transparent (Hagemann and Weber, 2015).

**Discrete intraday** markets are organized as a sequence of auctions which are called at specific predefined times and have specific delivery horizons. In contrast to continuous intraday markets, the auction-based intraday market is cleared once for the whole delivery horizon and shows one equilibrium price – the **market marginal price** – and the quantity for each delivery period (e.g. one hour), which increases price transparency. In this case, all bids are cleared at the market marginal price for a certain delivery period. The main disadvantage of this model compared to continuous trade is that a market participant who wants to trade has to wait until the next auction is carried out. In this case, the timing of auctions may not suit all participants' needs for trading.

An alternative design is the **hybrid intraday market** model, which is mainly based on continuous trading and may include one or more auctions to increase market liquidity. This design has been applied in Germany since December 2014. The German hybrid model is based on a daily auction that is held at 3pm of the day before operation where electricity can be traded for delivery in the 96 quarterly-hour intervals of the following day; a continuous market starting at 3pm of the day before operation where all hourly periods of the following day can be traded; and a continuous market starting at 4pm of the day before operation where all 96 quarterly-hour periods of the following day can be traded.

The above-mentioned market designs may affect significantly the participation of renewable generators in intraday trading and, consequently, system balancing. These arrangements are further discussed in the following subsections.

### 5.1.1. **Intraday market gate-closures**

As mentioned in Section 2.1.1, most of European intraday markets are based on continuous trading while in Italy and in the Iberia Peninsula intraday trading takes place in discrete auctions. Table 5.1 presents the gate-closures and delivery horizons of the Iberian and the Italian intraday markets.

**Table 5.1: Gate-closures and delivery horizons of the Iberian and Italian intraday markets**

| | ID1 | ID2 | ID3 | ID4 | ID5 | ID6 | ID7 |
|---|---|---|---|---|---|---|---|
| Iberian ID gate-closure time | 18:45 (D-1) | 21:45 (D-1) | 1:45 (D) | 4:45 (D) | 8:45 (D) | 12:45 (D) | 18:45 (D) |
| Iberian ID delivery horizon (hours) | 1-24 | 1-24 | 5-24 | 8-24 | 12-24 | 16-24 | 22-24 |
| Italian ID gate-closure time | 15:00 (D-1) | 22:45 (D-1) | 3:45 (D) | 7:45 (D) | 11:15 (D) | 15:45 (D) | - |
| Italian ID delivery horizon (hours) | 1-24 | 1-24 | 9-24 | 13-24 | 17-24 | 21-24 | - |

It can be observed in Table 5.1 that, depending on the delivery hour, intraday lead-times in Spain and Portugal vary from 3.25 to 7.25 hours, while the in Italian intraday market lead-times varies between 3.25 and 11.5 hours. On the other hand, in continuous intraday markets, regardless the delivery hour, trading can take place until, at least, one hour before real-time.

Figure 5.1 compares the gate-closures and delivery horizons of the discrete intraday market (the Iberian case example) and that of the continuous intraday market (considering a gate-closure of one hour before real-time). Compared to discrete auctions, continuous intraday market provides agents with higher possibilities of reducing their imbalances within the intraday timeframe due to gate-closures closer to real-time. This is particularly relevant for intermittent renewable producers since forecast errors can be significantly reduced for short lead-times.

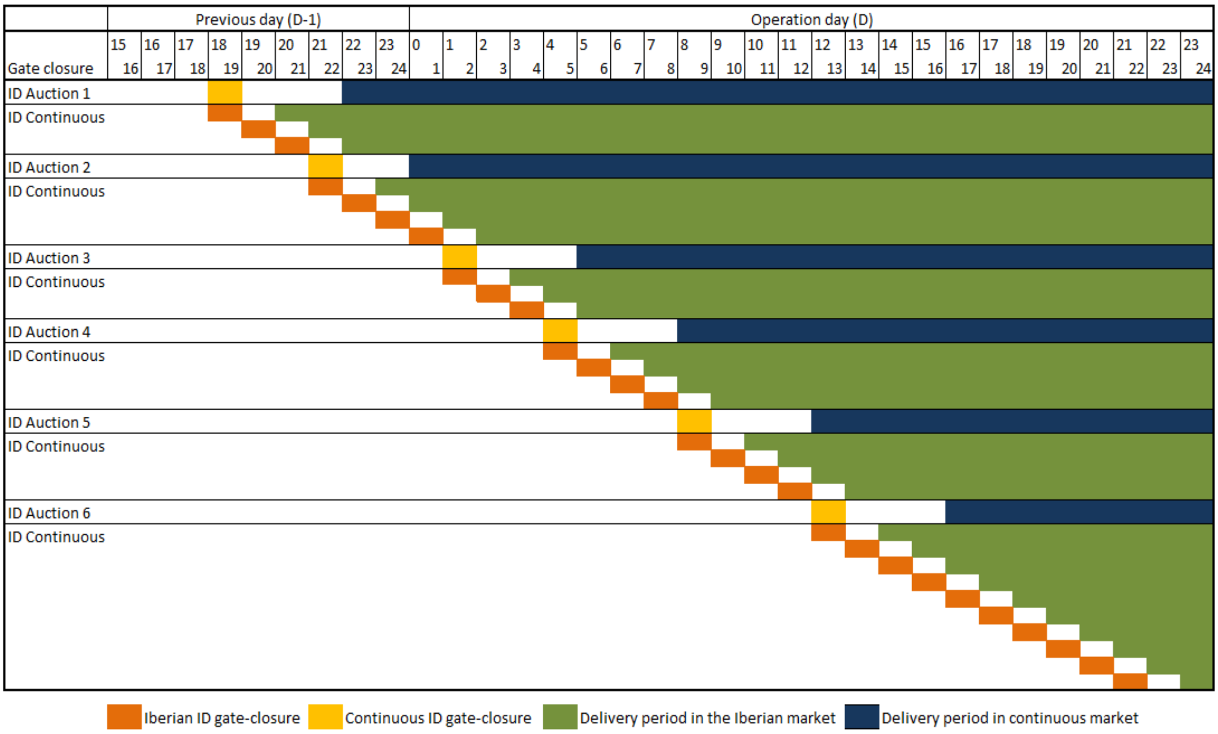



**Figure 5.1: Discrete *versus* continuous intraday gate-closures and delivery horizons**

In this respect, Figure 5.2 presents average aggregated wind production forecast errors calculated by the Spanish SO. According to data shown in the figure, in 2014 the average aggregated wind production forecast error varied between 9% and 12% in the day-ahead timeframe[30]; between 6.8% and 8% in the Iberian intraday timeframe; and, for a lead-time of one hour (typical lead-time for continuous intraday markets) the average forecast error is reduced to 4.5%.

In summary, **continuous trading provides greater flexibility** to market participants since trading is always possible. However, as mentioned in Section 2.1.1 **the lower liquidity of**

[30] The European day-ahead market lead-times vary from 12 up to 36 hours.

**continuous intraday** markets can limit the balance of renewable production through intraday trading. This is discussed in the next subsection.

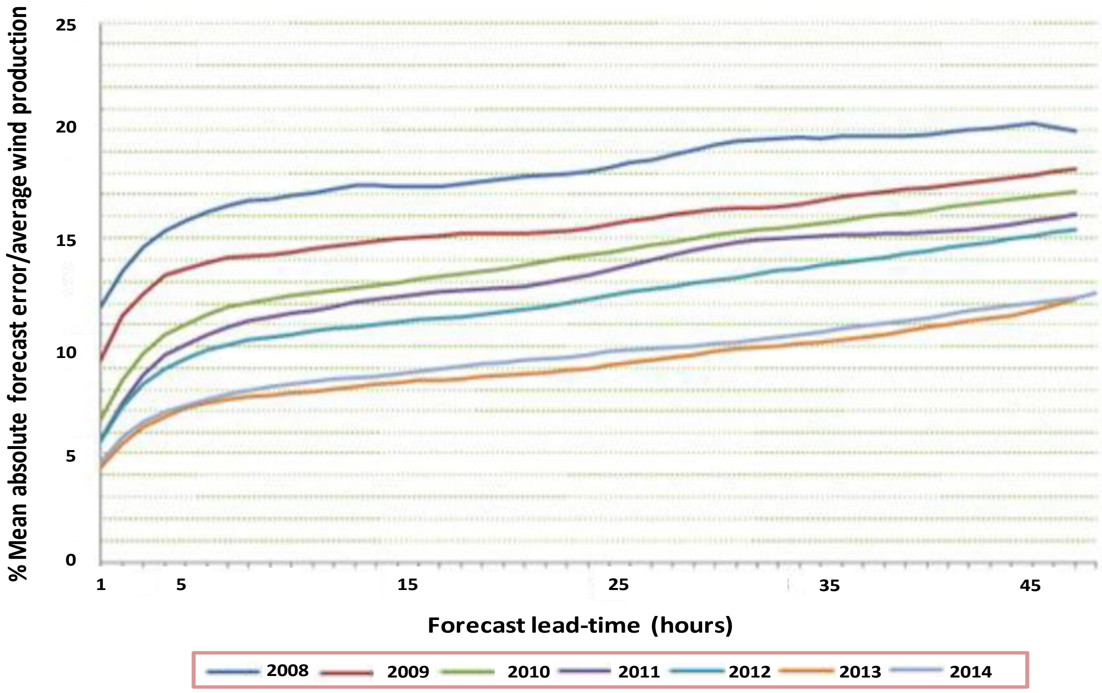



**Figure 5.2: Average aggregated wind production forecast error calculated by the Spanish SO prediction tool SIPREOLICO. Source: Alonso (2015).**

### 5.1.2. **Intraday market liquidity**

Although intraday market **liquidity** should not be considered an objective itself it is a **prerequisite to achieving more efficient balancing** of electricity systems (ACER and CEER, 2016). It is in general accepted that discrete auctions provides intraday markets with higher liquidity since they concentrate all transactions at specific points in time (Chaves-Ávila and Fernandes, 2014; Olmos et al., 2015; Weber, 2010).

Figure 5.3 presents average volumes traded in the Spanish intraday market and the average volumes of continuous trading in Germany as a percentage of volumes traded in the day-ahead market. These markets correspond to the most liquid discrete and continuous intraday markets, respectively. Regarding the values shown in the figure, the volume of the Spanish intraday market in 2012 was significantly higher than the ones observed in the following years. This is related to the priority dispatch of domestic coal-fired power plants during the period of 2010-2014, which had an important impact on the strategy adopted by companies owning coal power plants not under the priority dispatch rule. It is worth mentioning, during this period that domestic-coal fired power plants had priority dispatch over other thermal power plants. Since 2013 and 2014 renewable generation in Spain was significantly higher than in 2012, the impact of this rule on intraday trading was not as important as in 2012. This is further discussed by Chaves-Ávila and Fernandes, (2014).

As for continuous trading in Germany, it can be observed that traded volumes increased over the last years. This can be explained mostly by the introduction of the 15-minute contracts in December 2012, which helps dealing with intermittent renewable production intra-hour variability, and the introduction of the 3pm auction in 2015. Still, continuous intraday trading in Germany presents lower liquidity compared to the Spanish intraday market.

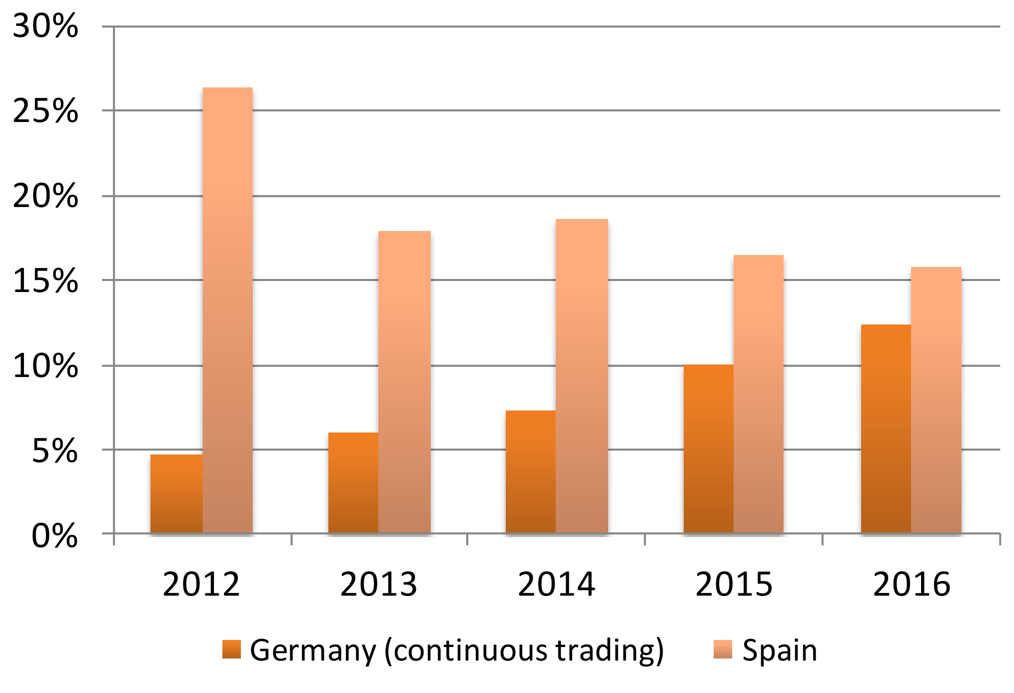



**Figure 5.3: Average volumes traded in the Spanish and the German intraday markets (% of day-ahead market volumes)**

Apart from the fact that **trades in continuous markets are typically dispersed** over the whole trading period, which reduces the liquidity of the market, **pay-as-bid pricing may prevent small market participants from trading** in continuous markets, which in turn also contributes to low market liquidity. As explained in Section 2.3.1.3, while marginal markets participants are incentivized to submit orders at their own marginal costs, in continuous markets agents have to estimate the system marginal price, which is a disadvantage for small players that do not have the same possibilities to forecast prices.

Furthermore, in pay-as-bid pricing systems agents cannot introduce price-taking orders as they do in marginal markets. Marginal markets ensure that all agents get the same price – which in perfectly competitive markets is equal to the system marginal cost – regardless their size and technical capabilities. In this respect, continuous intraday markets can impose high transaction costs on small market parties since obtained reasonable prices requires having a person looking continuously at the screen.

In this respect, Figure 5.4 shows monthly average intraday low, weighted average and high continuous intraday prices as percentages of the day-ahead market price in Germany, and Figure 5.5 presents Spanish weighted average intraday market prices as percentages of the day/ahead market price. It can be observed in the figure that continuous intraday market prices present much higher volatility (high and low prices) compared to marginal market prices.

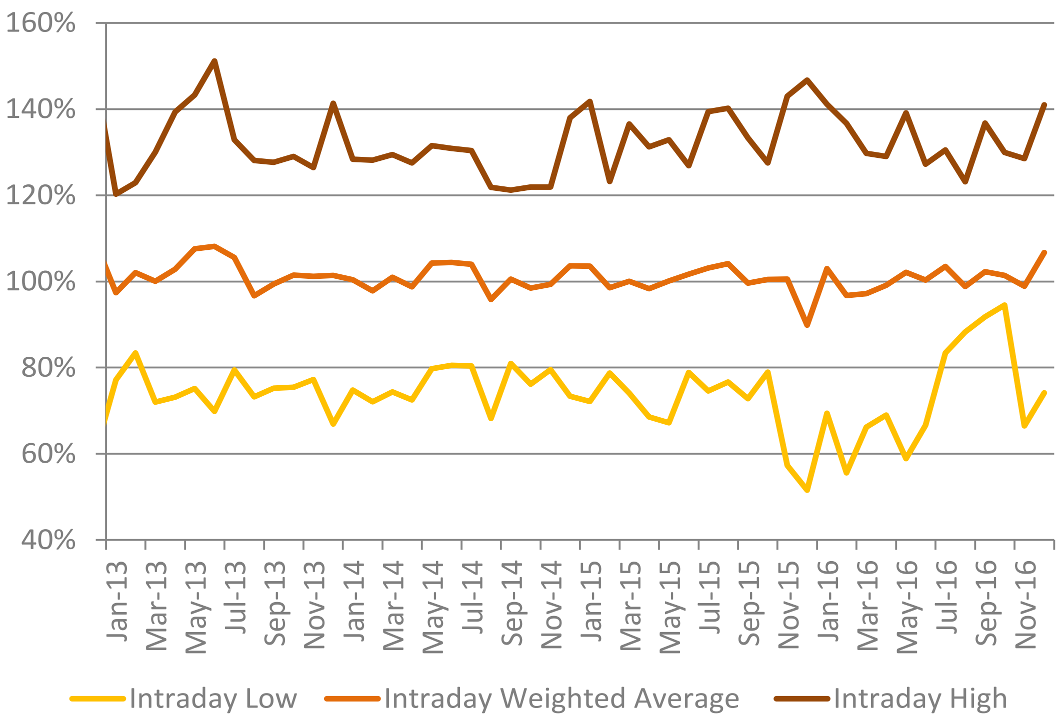



**Figure 5.4: German continuous intraday market average prices (% of day-ahead prices)**

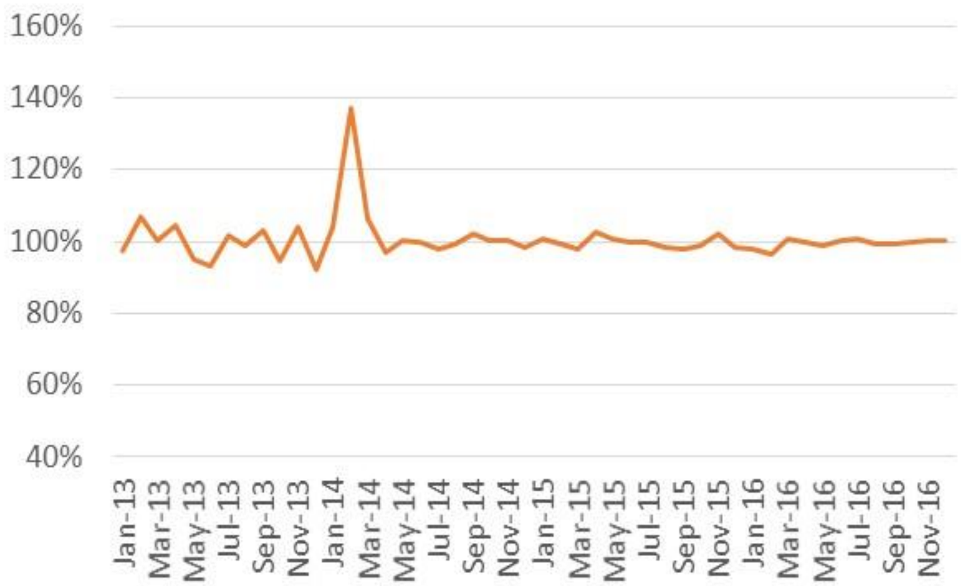



**Figure 5.5: Spanish intraday market price (% of day-ahead prices)**

Apart from this, **auction-based intraday** markets typically enable a better cross-matching of different products (e.g. matching a block of 4 hours with 4 hourly orders, or more complex combinations) which allows auctions to accommodate more complex products, represented in **complex bids** (Olmos et al., 2015). This **increases liquidity** since market participants' constraints can be more easily represented.

Finally, in **continuous markets** bid/ask orders are aggregated for the whole agent's portfolio, i.e. physical generation/consumption units' schedules cannot be monitored by other market participants. Furthermore, in several cases there is no physical delivery associated to these orders (i.e. speculative trades). These may result in a **barrier to market monitoring** since trades cannot be related to physical consumption/generation units, which put smaller agents at disadvantage in respect to large players since the former do not have the same resources to forecast market prices, which in turn depend on strategies adopted by market agents.

In conclusion, despite the fact that continuous markets provide market participants with higher flexibility since events occurring after the day-ahead market gate closure can be dealt with by continuous trading up to at least one hour before real-time, auction-based markets facilitates the participations of smaller agents such as renewable generators, hence increasing market liquidity.

In this respect, the **hybrid model** combines the advantage of continuous trading and auction-based intraday markets, i.e**. higher opportunities for trading** close to delivery and **higher market liquidity**. In the following subsection, the European intraday market target model is presented as well as the latest developments on the future design of national intraday markets.

## 5.2. The European intraday market target model

Pursuing its objective of integrating national electricity markets, the European Commission has established a **Target Model** for the intraday market which is based on **continuous trading** with implicit continuous allocation of cross-zonal transmission capacity. This model has been laid down into the EC regulation of the 24$^{th}$ of July of 2015 establishing a **guideline** for Capacity Allocation and Congestion Management **– CACM** (European Commission, 2015).

In order to establish a common **cross-border continuous intraday trading solution** across Europe where all cross-border capacities are allocated, power exchanges and SOs from several European countries have launched an initiative called the **XBID** (Cross-Border Intraday) Market Project (XBID, 2017). The purpose of the XBID initiative is to increase the overall efficiency of intraday trading by coupling national intraday markets and to allow market players to trade, manage risks and respond to changing conditions (such as varying wind forecasts), close to real-time operation (up to one hour ahead of delivery).

This single intraday cross-zonal market solution will be based on a common IT system linking the local trading systems operated by the power exchanges, as well as the available cross-zonal transmission capacity provided by the SOs. Orders entered by market participants in one country can be matched by orders similarly submitted by market participants in any other country within the IT systems' reach, provided that there is available cross-zonal transmission capacity. In this respect, the XBID intraday solution supports both explicit (whenever requested by regulatory authorities) and implicit allocation of transmission capacity.

To implement the XBID solution Local Implementation Projects (LIPs) have been set up, as shown in Figure 5.6. A LIP consists of one or more borders, one or more SOs and one or more power exchanges. The main tasks of the LIPs refer to the adaptation of local arrangements (i.e. contracts, procedures, physical and financial clearing, etc.) and IT system adjustments. They must also guarantee an equal treatment between power exchanges and implicit/explicit access to transmission capacity. The first **go-live phase**, which was initially planned for the third quarter of 2017, has been delayed to the **first quarter of 2018**.

**LIPs part of go-live Q3/2017**

| LIP | | Participants |
|---|---|---|
| 1 | Nordic | Fingrid, EnDK, SvK, Statnett, Nord Pool, EPEX |
| 2 | Kontek | EnDK, 50Hz, Nord Pool, EPEX |
| 3 | DK1/DE, DE/NL | EnDK, TenneT NL& DE, Amprion, EPEX, APX/Belpex, Nord Pool |
| 4 | NorNed | Statnett, TenneT NL, APX/Belpex, Nord Pool |
| 5 | FR/DE, CH/DE, CH/FR, DE/AT | Amprion, TransnetBW, APG, RTE, Swissgrid, EPEX, Nord Pool, Tennet DE |
| 6 | NL/BE | Elia, TenneT NL, APX/Belpex |
| 8 | FR/BE | RTE, Elia, APX/Belpex, EPEX |
| 9 12 | FR/ES& ES/PT | RTE, EPEX, OMIE, REE, REN |
| 11 | AT/CH | APG, Swissgrid, EPEX |
| 13 | Baltic | Elering, Litgrid, AST, Fingrid (Estlink) Svenska Kraftnät (NordBalt, Nord Pool |

**LIPs going live at a later stage**

| LIP | | Participants |
|---|---|---|
| 7 | BritNed | BDL, NG, TenneT NL, APX |
| 10 | IFA | RTE, NG, Nord Pool, EPEX |
| 14 | INB | ADMIE, APG, ELES, RTE, Swisgrid, Terna, BSP, EPEX, EXAA, GME, LAGIE, Nord Pool |

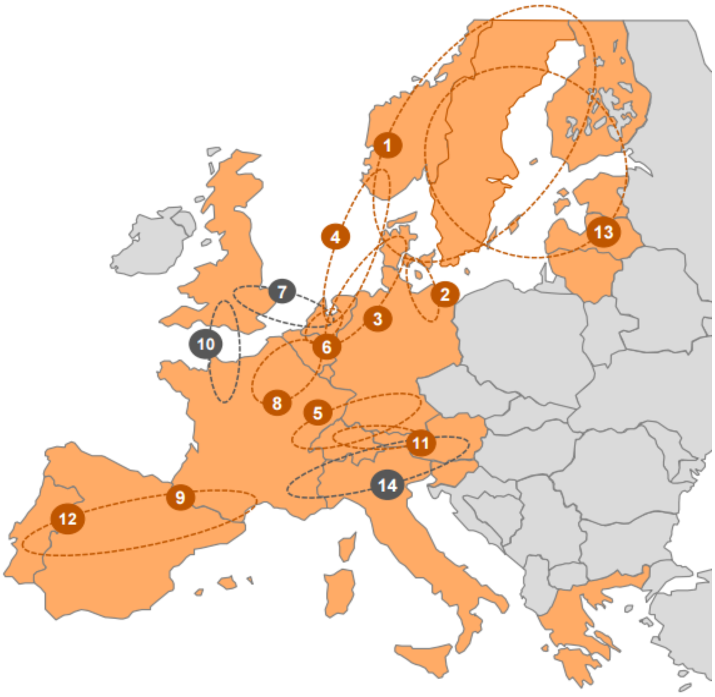



**Figure 5.6: XBID Local Implementation Projects (LIPs)**

Regarding the CACM guideline, it is required that two years after the entry into force of this regulation all SOs shall develop a proposal for a **single methodology for pricing intraday cross-zonal capacity** which must reflect market congestion.

In this respect, as pointed out by PMI Consulting (2014), in auction-based markets with implicit capacity allocation the price limits of all orders (i.e. willingness to pay/to be paid) is known by the matching algorithm and this information allows a welfare optimization process which is not performed per trade but for all orders simultaneously. This optimization process determines whether capacity is scarce or not. In case it is not, the price of the capacity connecting two bidding zones is zero; in case it is scarce, the price of cross-zonal capacity is the price difference between the two bidding zones.

In continuous trading, market participants can see the prices and quantities of the orders which are already in the order book (i.e. list of buy and sell bids); then the price which he sends into the order book is strongly influenced by the prices of the orders which are already in the order book. His willingness to pay/to be paid is not actually known and does not directly contribute to price formation. Furthermore, in continuous market, capacity is allocated based on a first-come first-served principle according to the orders available in the order book. When capacity has been fully used, then it becomes scarce. In this case, no cross-zonal trade is possible any longer and, consequently, capacity is not properly priced.

In summary, while continuous trading is the target model for the European intraday market, it does not allow for intraday cross-zonal capacity price to reflect congestions. Therefore, none of the main intraday market designs (auction-based and continuous trading) complies by themselves with the requirements of the CACM guideline, which also include non-discriminatory access to capacity, promotion of fair price formation and **effective competition** in generation, trading, and supply of electricity. For this reason, ENTSO-E recommends the development of **hybrid models based on implicit auctions and continuous trading** (ENTSOE, 2016). In this respect, the Italian and the Iberian market operators are currently studying the combination of their respective auction-based intraday markets and continuous trading, as established in the CACM guideline. This study focus on the maintenance of intraday auctions at a national/regional level.

It is worth mentioning that regulation on CACM allows relevant market operators and SOs of different bidding zones to jointly submit a common proposal for the design and implementation of **complementary regional intraday auctions** where deemed necessary. In this case, the proposal must be subjected to consultation with stakeholders, including the relevant authorities of each Member State. In order to hold regional intraday auctions, continuous trading within and between the relevant bidding zones may be stopped for a limited period of time before the intraday cross-zonal gate closure time, which must not exceed the minimum time required to hold the auction and in any case 10 minutes (European Commission, 2015).

Finally, it is important to point out that the final design of the European intraday market is not defined yet. In this respect, in the following section empirical data from the Spanish and the German intraday markets are used to shed a light on this discussion.

## 5.3. Evidence from the Spanish and the German intraday markets

This section compares the intraday market outcomes in Spain and Germany. These countries have a very similar share of electricity produced by wind and solar generators – 24% and 23% in Spain and Germany, respectively. Furthermore, the intraday markets of these countries serve as interesting examples of market design options for intraday trading.

### 5.3.1. Intraday trading

As discussed in Section 5.1 continuous intraday markets provide market participants with an opportunity to trade continuously up to very close to delivery. On the other hand, barriers to entrance faced by small market participants and trades dispersed over the whole trading period in general result in lower liquidity in continuous markets compared to auction-based markets. Regarding intraday trading, it is important to point out that other factors may affect significantly the volumes of energy trades such as priority dispatch for certain technologies, market concentration, imbalance pricing, regulatory framework for renewable generators, as discussed by Furió and Lucia (2009) and Chaves-Ávila and Fernandes (2014).

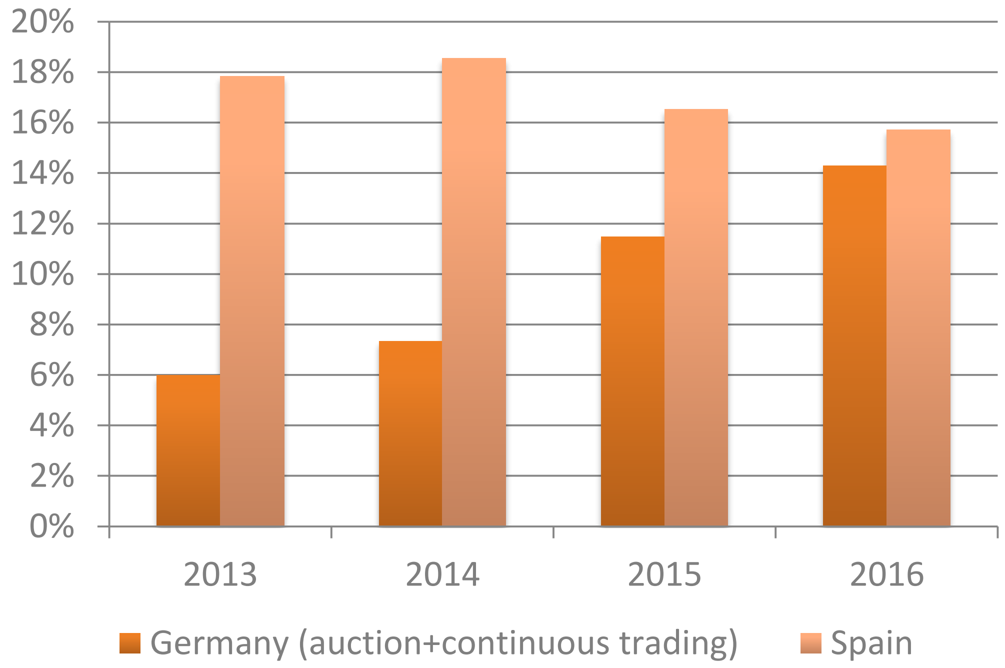



**Figure 5.7: Average volumes traded in the German (auction and continuous) and Spanish intraday market (% of day-ahead market)**

Figure 5.7 compares the total volume traded in the German and the Spanish intraday markets. It can be observed in the figure that the introduction of the 3pm auction had a positive impact on the volumes traded in the German market. Despite this, the volumes traded in the Spanish market still remain higher than the energy traded in the German one.

In this respect, in general, a first auction allows for adjustments related to strategic positions of agents in different markets/procedures. For instance, in Spain, after the day-ahead market, market parties can participate, for instance, in the day-ahead congestion management procedure, the additional upward reserve market (when called by the SO) or the aFRR market, as explained by Chaves-Ávila and Fernandes, (2014). If committed in those market, agents must adjust their previous (day-ahead) market schedules in the intraday market. On the other hand, auctions with short lead-times contribute to adjustments related to better production/consumption forecasts.

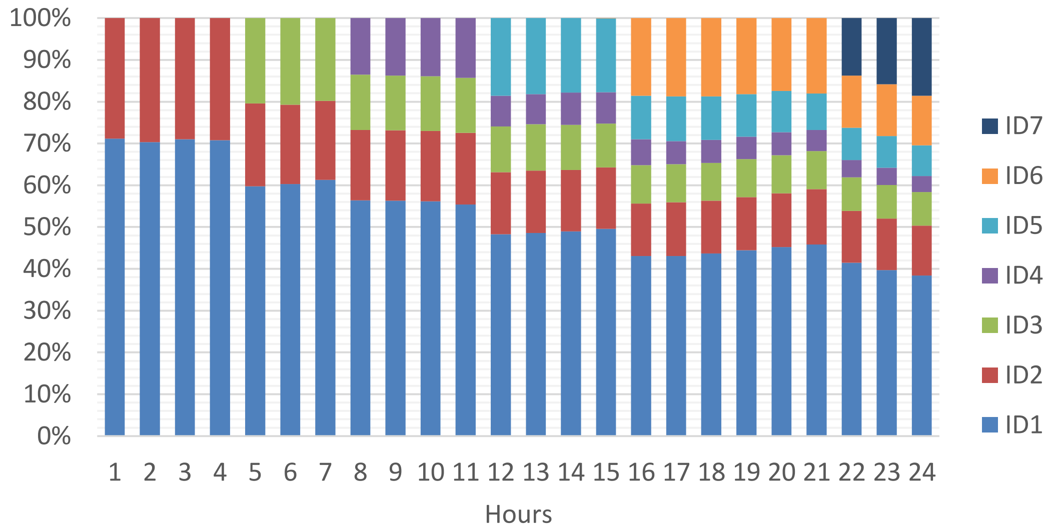



**Figure 5.8: Average hourly volumes traded in the seven auctions of the Spanish intraday market in 2016 (% of the total volume traded in the intraday market)**

Figure 5.8 shows the hourly volumes of energy traded in the different auctions of the Spanish intraday market. First, it can be observed that the volumes traded in the first auction are significant for all delivery hours. Nevertheless, the percentage volumes traded in the first auction decrease as new auctions are carried out. It can be also noticed that, in general, with the exception of the energy traded in the first auction, higher volumes are traded in the last intraday auction for each delivery hour. This emphasizes the importance of closeness of gate-closures to delivery, especially under high penetration of renewable generation. In this respect, and taking into account barriers to the participation of small market parties in continuous intraday market, the introduction of more auctions in the German intraday market would contribute to higher market liquidity and facilitate the handling of imbalances by intermittent renewable producers and other small agents.

### 5.3.2. **Energy imbalances**

Final energy imbalances can also be a good indicator of well-functioning intraday markets[31]. Figure 5.9 compares final imbalances in Spain and in Germany as percentages of each country's electricity demand. In 2015, average energy imbalances in Spain corresponded to 3% of the Spanish demand while in Germany they corresponded to 2% of the German demand; in 2016, average imbalances in Spain and Germany corresponded to 2.2% of each country's demand. Regarding imbalances in Germany it is worth mentioning that intermittent renewable production under a feed-in tariff scheme (32.8 GW of solar and 6 GW of wind power) are exempted from balancing responsibility, which is transferred to the SO, reducing the amount of imbalances.

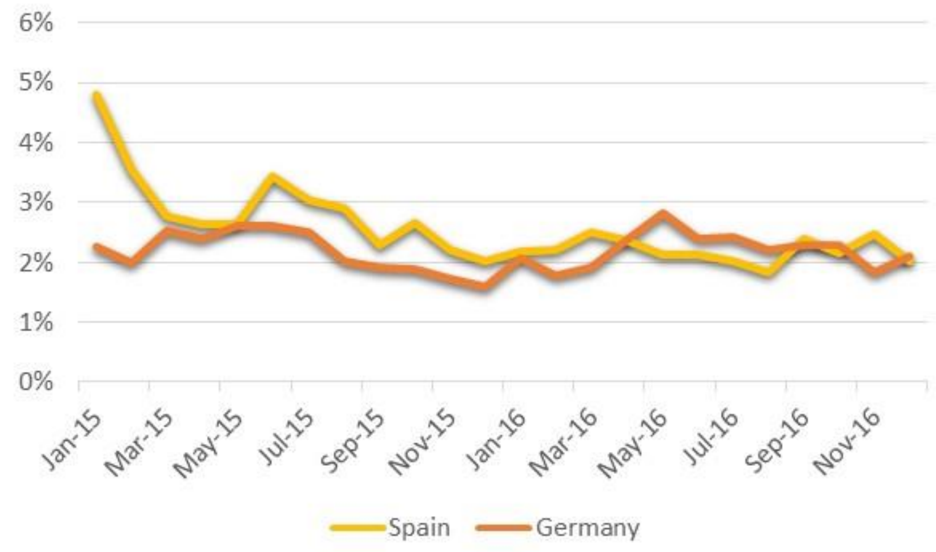



**Figure 5.9: Average final imbalances in Spain and Germany (% of electricity demand)**

[31]Notice that market participants may have intended imbalances regardless of the well-functioning of intraday markets. For instance, if a market agent expects that the system will be short, he can buy "extra" energy in the intraday market provided that it gets a price lower than the one resulting from the day-ahead market. If the system is finally short, this agent will receive the difference between the day-ahead market price (the imbalance price for long positions when the system is short, as explained in Section 3.2.2) and the intraday market price.

Furthermore, despite the gate-closure closer to the delivery period, continuous trading may not lead to lower imbalances compared to discrete intraday trading. In this sense, the combination of auctions with continuous trading sessions can lead to higher opportunities for all market participants to adjust their market schedules according to better production and consumption forecasts and reduce non-intended imbalances.

Regarding imbalances in Spain, it is worth pointing out that the reduction observed from 2015 to 2016 can be explained by: (i) the allocation of balance responsibility for the imbalances related to estimated and real network losses on consumption units, as explained in Section 3.2.2.2; and (ii) the participation of renewable generators in mFRR and RR balancing energy provision, which delayed the gate-closure time for these units, from the lead-times of the Spanish intraday market to the lead-times of the mFRR and RRe markets (see Sections 4.2.2 and 4.2.3).

Finally, Figure 5.10 presents the differences between imbalance prices applied to BRPs increasing the system imbalance and weighted average intraday market prices. It can be observed that, in general, the difference between imbalance and intraday prices are significantly higher in Germany than in Spain.

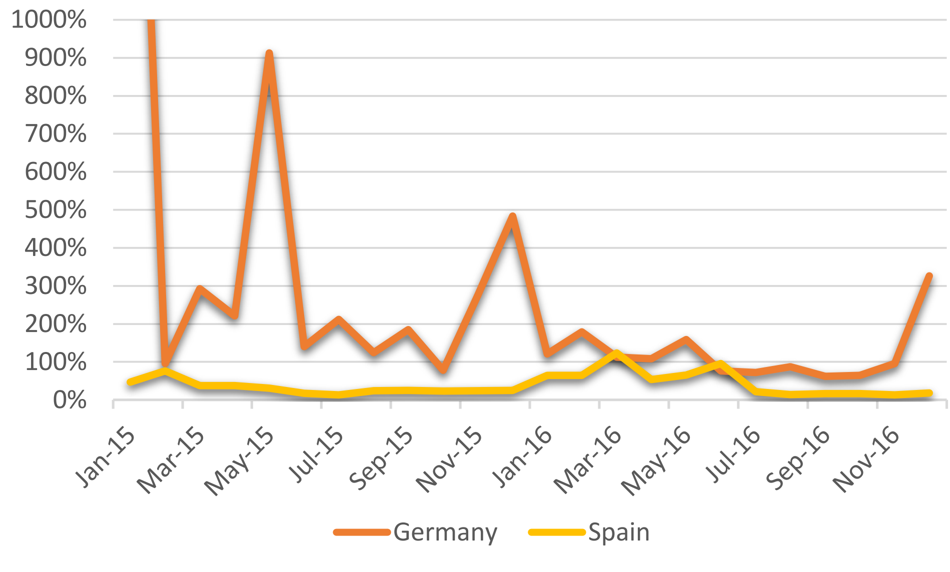



**Figure 5.10: Spread between imbalance and intraday market prices (% of intraday prices)**

As explained in Chapter 3, imbalance prices are directly related to the price of balancing energy which in turn depends on balancing energy provision costs and on the amount of activated balancing energy. In this respect, it can be observed in the figure that the difference between imbalance and intraday prices in Germany in 2015 was significantly higher than in 2016 – in 2015 imbalance prices were in average around 40 €/MWh higher than intraday prices, while in 2016 this difference decreased to 25 €/MWh. This can be explained by the higher fuel prices in 2015 compared to 2016, when renewable production increased significantly. Even without taking into account the effect of fuel prices, in 2016 the average difference between imbalance and intraday prices in Germany was more than two times higher than the observed in the Spanish market (approximately 9 €/MWh), which may indicate higher activation of balancing resources to deal with imbalances in real-time.

## 5.4. Conclusions

Continuous intraday markets can potentially provide market participates with opportunities to trade up to very close to delivery, which may contribute to intermittent renewable production balancing. However, barriers such as low liquidity, pay-as-bid pricing and high monitoring costs may prevent small players to optimize their schedules in continuous intraday market. On the other hand, auction-based intraday markets facilitate the participation of renewable generators and other smaller market agents. Therefore, taking into account the target model laid down in the European Commission's regulation CACM, it is strongly recommended that that the European intraday market is based on auction (**at an EU-wide level) and complemented with continuous trading** , where all market participants can handle further unintended imbalances not dealt with within intraday auctions. In this respect, as discussed in Section 5.3.1, traded volumes increase with the number of auctions. In any case, the costs of increasing the number of auctions must be compared to the benefits achieved by improved market scheduling. Finally, for the integration of national intraday auctions, the Price Coupling of Regions system, through which national European day-ahead markets are coupled, could be used.

# Chapter 6: Conclusions, original contributions, publications and future research

This last chapter is dedicated to present the conclusions that resulted from the research carried out in this thesis. For this purpose, first, the main conclusions are briefly summarized. Then, the original contributions are described and the publications resulting from the research line of this thesis are listed. Finally, future research lines related to the topic of this thesis are briefly described.

## 6.1. **Main conclusions**

The European Union policy goals include ambitious targets for the shares to be achieved by renewable energy sources in the electricity generation mix within the next years and up to 2050. Increasing amounts of intermittent renewable generation imposes significant challenges to the planning and operation of power systems. In this sense, one of the main challenges imposed by **renewable energy intermittency** on power system operation refers to the maintenance of the balance between generation and demand at all times (i.e. **electricity balancing**).

Electricity balancing involves two main pillars, **active balancing** and **passive balancing**. While the former refers to the activation of BSPs by the SO for balancing purposes, the latter is related to the provision of adequate incentives for BRPs to support the system balance during operation. In this respect, **intraday trading** plays an important role in electricity balancing since it provides market parties with an opportunity to adjust their schedules closer to real-time and prior to the activation of more expensive (balancing) resources.

Market arrangements related to electricity balancing have been designed based on the characteristics and technical capabilities of traditional power suppliers – i.e. conventional generators – and in a context when renewable generation intermittency was not an issue. These has led to **low market flexibility and prices that do not reflect (close to) real-time electricity provision costs**, which together limit the contribution from renewable power producers and other potential suppliers such as demand response and alternative storage technologies to electricity balancing.

In this respect, the European Commission has developed **guidelines for the harmonization of national electricity markets** aiming at eliminating cross-border barriers and facilitating the integration of massive amounts of renewable generation. Although these guidelines establish general principles for the design of the future European electricity market, there are several open issues regarding the most adequate arrangements leading to an efficient integration of renewable production in electricity markets.

In this context, this thesis has analyzed market design options affecting electricity balancing and has shed light **on adequate market arrangements** leading to a more efficient integration of intermittent renewable generation in power systems. The main conclusions of this thesis are summarized below.

### 1. Arrangements for effective passive balancing

Passive balancing can be understood as the contribution of market parties to system balancing without having been requested by the SO. A main condition to passive balancing is the existence of cost-reflective imbalance prices; without cost-reflective imbalance prices, BRPs may have distorted incentives and worsen the system imbalance.

The existence of cost-reflective prices depend not only on the imbalance pricing system, but also on the arrangements related to the calculation of imbalances and to the settlement period. In this respect, based on the study performed in Chapter 3, this thesis advocates for the use of **single imbalance pricing** since it provides a level-playing field for small and large BRPs, while providing fair allocation of balancing costs and incentivizing BRPs to support the system balancing.

However, it was pointed out that if imbalance prices are distorted single pricing may lead to worse outcomes than dual pricing systems. In order to avoid the provision of distorted incentives for BRPs, **all imbalances must be covered by a BRP**. The existence of imbalances not related to a difference between actual production or consumption and the final market schedule may lead to excessive penalization of market participants.

Furthermore, **short settlement periods** lead to a more efficient cost-reflective allocation of imbalance costs since the activation of balancing energy bids will in general decrease at the same time that the “identification” of BRPs causing the imbalance improves.

### 2. Arrangements for efficient active balancing

Active balancing refers to changes in production or consumption on a request from the SO to balance the system in real-time. For this purpose, the SO procures balancing capacity and balancing energy products.

Although the reservation of balancing capacity may be required for real-time balancing purposes, SOs procure balancing capacity in order to safeguard system operational security, guaranteeing the provision of sufficient balancing energy during real-time operation in case large imbalances and/or contingencies (e.g. large generation outage) occur during real time. In this sense, the procurement of balancing capacity cannot be directly related to real-time imbalances.

Despite this, balancing capacity and balancing energy products are jointly procured in several European countries. The fact that balancing capacity is typically procured far ahead of real time imposes a strong barrier to the contribution of renewable generation and other new market players in active balancing. Balancing markets in general have been designed based on the characteristics of traditional suppliers of balancing services, i.e. conventional generators, limiting the participation of other potential suppliers in these markets.

In this respect, based on the analyses carried out in Chapter 4, the **separation between balancing capacity and balancing energy** products **and between upward and downward balancing capacity** is strongly recommended. Separated procurement of different balancing products could not only facilitate a higher participation of new potential providers, such as renewable producers and demand, but also increase efficiency in balancing services procurement. The latter is related to the fact that higher competition among providers enhances efficiency and that actual (provision) costs are more likely to be revealed when different products are procured separately – single (or joint) products are generally bought at the price of the product of highest cost.

Furthermore, **price limitations should be avoided**. For instance, negative prices reflect the system conditions during super off-peak hours when the cost of downward reserve provision by thermal power plants operating very close to their minimum output values can be very high. Therefore, the inexistence of negative energy prices prevents imbalance prices from reflecting balancing costs during these situations and may provide distorted incentives to market parties. Also, **extra penalties** for deviations from balancing energy provision schedules **should be avoided** since they may discourage renewable producers and other smaller providers from participating in balancing markets. Instead, the imbalance settlement should provide adequate incentives for BRPs (including BSPs) to keep the system balanced as much as possible.

Finally, there should be **no discrimination among different technologies** in the provision of balancing services. On the contrary, all potential providers should be allowed to participate in balancing service provision as long as technical requirements are fulfilled.

### 3. Intraday market design

Intraday markets represent a relevant opportunity for market agents to balance their portfolio by trading closer to the delivery period, taking benefit from more updated information regarding production and/or consumption.

Currently, two main intraday market designs are used in Europe: continuous and discrete intraday trading. In continuous intraday markets, participants are provided with an opportunity to handle their imbalances as soon as they appear. Orders are executed as soon as the bid price equals or exceeds the ask price in a continuous way until the market gate-closure time (from 45 minutes to one hour before real-time) and trades are settled according to pay-as-bid pricing. Discrete intraday markets are organized as a sequence of auctions which are called at specific predefined times and have specific delivery horizons. In contrast to continuous intraday markets, the auction-based intraday market is cleared once for the whole delivery horizon and shows one equilibrium price – the market marginal price.

While continuous intraday trading provides market participates with opportunities to trade up to very close to delivery, it imposes barriers to small participants, such as pay-as-bid pricing, higher costs related to the trading activity, and lower market liquidity. In auction-based markets these barriers are eliminated. On the other hand, lead-times of discrete intraday markets may not optimize intraday schedules due to longer lead-times, which may not be adapted to participants such as intermittent renewable producers' needs. In this respect, the European Commission has established on its regulation on Capacity Allocation and Congestion Management that target model for the European intraday will be based on continuous trading.

Based on the analyses performed on Chapter 5 and on current development in national markets, it is recommended that th**e European intraday market based on continuous trading should be complemented with European-wide intraday auctions**.

It is worth pointing out that the recommendations previously described will facilitate an efficient contribution to electricity balancing not only from renewable generators but also from other potential resources such as demand response.

## 6.2. **Original contributions**

This thesis provides a complete understanding of electricity balancing and analyzes in detail the incentives provided by related market arrangements to new market participants, in particular renewable producers, to contribute the power system balance. In this respect, the main original contributions of this PhD are summarized below:

1. A **complete critical review of concepts** related to and affecting electricity balancing, associating those with their respective market arrangements. In this respect, the main original contribution of this thesis is that provides a complete understanding of electricity balancing, including the role of the different actors involved, the mechanisms used by the SO to balance the system, how balancing products are defined and procured, how incentives are provided to market participants and the procedures and/or markets affecting balancing actions.
2. A detailed and complete analysis of all **imbalance settlement arrangements** impacting the costs reflectiveness of imbalance prices, identifying relevant barriers and proposing solutions. Regarding this analysis, the main original contribution of this thesis refer to the detailed study of the impact of the settlement period and the imbalances not caused by BRPs (i.e. imbalances that do not refer to deviations from actual production/consumption and the market schedule) on the (single) imbalance price. The main conclusion of this analysis is that in the presence of distortions related to long settlement period and the existence of imbalances not caused by BRPs, single imbalance price may incentivize BRPs to increase the system imbalance, in particular in a context where (close to) real-time information regarding imbalance prices is provided to BRPs.
3. A detailed and complete analysis of the main arrangements preventing the participation of renewable generators in **balancing markets**, identifying relevant barriers and proposing solutions. In this respect, the main original contribution of this thesis is the distinction between active balancing and the provision of balancing capacity. It is argued that higher efficiency can be achieved in balancing markets if balancing capacity and balancing energy are procured separately. This arrangement not only facilitates the participation of renewable generators and other potential suppliers of active balancing in balancing markets but allows for the price of each product to reveal its actual provision costs. In the same line, separation upward and

downward balancing capacity markets can increase efficiency in balancing markets.

4. An updated critical discussion on the proposals for the European intraday market design as well as their implications on the participation of renewable producers and other small players in intraday trading. Regarding intraday trading, the main original contribution of this thesis is the comparison of characteristics and market outcomes of discrete and continuous intraday markets. According to this study, despite the gate-closure closer to real-time in continuous markets, intraday auctions facilitate the participation of renewable generators and other smaller market participants. Therefore, this thesis argues in favor of auction-based intraday markets complemented with continuous trading.

## 6.3. Publications related to the thesis

This section presents the publications that have resulted from the PhD candidate's research topic. The list of publications is divided into international journal papers, national journal papers and international conference papers.

Of the list shown below, publication 1 describes most of the results and conclusions from the analyses performed in Chapter 4 of the thesis and some insights from the study carried out in Chapter 3. Some of the concepts described in Chapter 2 are also briefly introduced in the paper. Publication 2 presents the basis for the analyses carried out in Chapter 5 and part of its conclusions.

Publications 3, 4, and 5 contain analyses that contributed to the PhD candidate deep understanding of the impact of intermittent renewable generation on power system operation and on balancing needs. Furthermore, the research that led to the publication of those papers contributed to the expansion of the PhD candidate knowledge on the functioning of electricity markets.

Remaining publications (6-11) were also a result of the PhD candidate's research on the integration of intermittent renewable generation in power system operation. All of the papers presented in international conferences (8-11) were improved and later published in national and international (JCR) journals.

**International journal papers**

1. C. Fernandes, P. Frías, J. Reneses. *Participation of intermittent renewable generators in balancing mechanisms: a closer look into the Spanish market design*. Renewable Energy. vol. 89, pp. 305-316, April 2016.

2. J.P. Chaves, C. Fernandes. *The Spanish intraday market design: a successful solution to balance renewable generation?* Renewable Energy. vol. 74, pp. 422-432, February 2015.

3. I. Boie, C. Fernandes, P. Frías, M. Klobasa. *Efficient strategies for the integration of renewable energy into future energy infrastructures in Europe - an analysis based on transnational modeling and case studies for nine European regions*. Energy Policy. vol. 67, pp. 170-185, April 2014.

4. C. Fernandes, P. Frías, L. Olmos. *Expanding interconnection capacity to integrate intermittent generation in the Iberian Peninsula*. IET Renewable Power Generation. vol. 7, no. 1, pp. 45-54, January 2013.

5. C. Fernandes, P. Frías, J.M. Latorre. *Impact of vehicle-to-grid on power system operation costs: the Spanish case study*. Applied Energy. vol. 96, pp. 194-202, August 2012.

**National journal papers**

6. C. Fernandes, P. Frías. Análisis del impacto en España de la generación renovable en el periodo 2020-2050. Anales de Mecánica y Electricidad. vol. LXXXVIII, no. II, pp. 13-19, April 2011.

7. C. Fernandes, A. Malpica, P. Frías. Análisis del impacto económico de distintas soluciones tecnológicas para la integración masiva de generación renovable en el sistema eléctrico español en el horizonte 2020-2050. Anales. June 2016.

**International conference papers**

8. C. Fernandes, M. Vallés, P. Frías, Economic assessment of using FACTS technology to integrate wind power: a case study, PowerTech 2013. Grenoble, France, 16-20$^{th}$ June 2013.

9. C. Fernandes, P. Frías, Impact of intermittent generation on the expansion of the Spanish power system interconnection capacity, IEEE PES Trondheim PowerTech 2011. ISBN: 978-1-4244-8419-5, Trondheim, Norway, 19-23rd June 2011.

10. C. Fernandes, P. Frías, L. Olmos, A. Ramos, T. Gómez, A long-term prospective for the Spanish electricity system, 7th Conference on the European Energy Market - EEM10. ISBN: 978-1-4244-6838-6, Madrid, Spain, 23-25th June 2011.

11. C. Fernandes, P. Frías, L. Olmos, A. Ramos, T. Gómez, Economic impact of plug-in hybrid electric vehicles on power systems operation, 33rd IAEE International Conference. Río de Janeiro, Brazil, 06-09th June 2010.

## 6.4. Future work

In this thesis, theoretical analysis and empirical evidence was used to identify relevant barriers and propose solutions for the adaptation of market arrangements to facilitate the contribution of integration of renewable production to electricity balancing. The work carried out in this thesis raised other relevant research questions that, due to scope limitations, could not be addressed here. These research questions can be dealt with in future work and are summarized below:

- Although several of the recommendations proposed in this thesis regarding the adaption of market design options related to electricity balancing would in principle facilitate the **contribution of demand-response to the system balance**, no specific arrangements related to this participation were studied here. In this respect, while there are several studies related to the deployment of demand-side management, there is little research analyzing in detail the participation of demand-response in the different balancing markets. This topic is particularly relevant since one of the goals set by the European Commission in its guideline on electricity balancing is to facilitate the participation of demand, as well as other potential suppliers as electric vehicles, storage, etc., in balancing markets.

- Taking into account the recommendations proposed in this thesis, a very interesting continuation of this research line is the study of **possible strategies of adopted by new market players** (renewable generators, demand-response, etc.) in offering different electricity-related products in other to maximize their benefits. In this respect, not only the products related to the market timeframe analyzed in this thesis (i.e. very short-term) should be taken into account but also longer-term products (e.g. hedging related products, participation in capacity mechanisms, etc.) should be analyzed.
- Another important topic not dealt with in this thesis is the **integration of national intraday and balancing markets in Europe**. As mentioned in previous chapters, the main goal of the guidelines developed by the European Commission is the harmonization of national electricity markets, eliminating cross-border barriers and facilitating the integration of massive amounts of renewable generation. Since the provisions established in these guidelines leaves room for the adoption of different design options in national markets (both intraday and balancing markets), a possible continuation of this research line is the assessment of the impact of the lack of harmonization of national designs on the integrated European market's outcomes.

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