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SYSTEM COSTS

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Energy Sustainability

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ABSTRACT: A successful deployment of power generation coming from variable renewable sources (VRES-E), such as wind and solar photovoltaic, strongly depends on the economic cost of system integration. This paper, in seeking to look beyond the impact of RES-E generation on the evolution of the total economic costs associated with the operation of the electricity system, aims to estimate the sensitivity of balancing market requirements and costs to the variable and non-fully predictable nature of intermittent renewable generation. The estimations reported in this paper for the Spanish electricity system stress the importance of both attributes as well as power system flexibility when accounting for the cost of balancing services.

JEL Codes: D47, L51, Q41, Q42, Q47

Keywords: Electricity market design, balancing services, renewable energy, variable and intermittent generation, system flexibility

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1. INTRODUCTION

In recent years, there has been an unprecedented increase in the presence of renewable energies in electricity systems. Considering its benefits, not only in reducing greenhouse gas emissions from energy generation and consumption but also in reducing external dependence on imports of fossil fuels, their promotion has become a policy priority for governments all over the world (Mir-Artigues et al., 2015). In December 2008, the European Union (EU) adopted its Energy and Climate package, a framework where specific objectives in terms of overall share of energy from renewable sources (RES), GHG emissions reduction (compared to 1990) and energy efficiency were established. With regards to renewable energies, an ambitious target has been set. For 2020, a 20% share of renewable energy sources in final energy consumption has to be achieved. A direct consequence of this objective is that renewable energy sources (RES-E) in electricity generation are expected to expand from 20.3% of electricity output in 2010, to around 33% in 2020, in order to meet the objective set by the European Commission.

This promotion of renewable energy has had a predictable impact on energy market prices, the relationship between RES-E deployment and wholesale and retail electricity price being a current area of interest for researchers (see Gelabert et al., 2011; Ciarreta et al., 2014; Costa-Campi and Trujillo-Baute, 2015). In general terms, consumers finally pay for support for renewable electricity in their electricity bills. Through the access tariffs the money to finance the burden associated with the promotion of RES-E promotion schemes is raised. At the same time, RES-E generation with priority of dispatch on the wholesale market displaces and reduces the demand for conventional electricity – with higher variable costs -. The substitution of conventional generation plants by RES generation therefore reduces the wholesale marginal price (merit order effect). The combined final impact on consumers of both effects depends on whether the reduction in the wholesale electricity market offsets the increase in final price due to RES-E support mechanisms.

Nevertheless RES-E deployment involves other interactions that may affect final electricity prices. The growth in RES-E during recent years largely reflects the expansion of two main sources, namely, wind and solar power. In the EU the quantity of electricity generated from wind turbines has increased more than five-fold since 2002 (Eurostat, 2014), and the growth in electricity generated from solar power has been even more dramatic, rising from just 0.3 TWh in 2002 to reach 71 TWh in 2012. These changes in the energy mix present profound implications for many aspects of power system operation and control (Pérez-Arriaga and Batlle, 2012) due to the nature of both wind and solar technologies. Wind and solar photovoltaic (PV) generation are both intermittent technologies, which means that energy output coming from these sources is variable over time and non-fully predictable.

A high penetration of variable and partially unpredictable renewable generation capacity imposes new flexibility requirements on System Operators (SO) in guaranteeing instantaneous equilibrium between demand and supply. The variability of renewable generation requires that the power system be operated with a high degree of flexibility, so as to keep pace with the fluctuating net load, defined at each instant as the difference between total energy consumption and total variable renewable production. The application of these flexibility requirements can affect final prices and, as pointed out by the European Commission, the costs of renewable market integration, such as balancing costs, need to be considered to compute the economic impacts of an increasing penetration of variable RES-E (VRES-E) on electricity markets.

The integration of variable and uncertain renewable generation sources increases the flexibility needed to maintain the load-generation balance. From a system perspective, integrating non-manageable generation constitutes a challenging task. Aspects such as low availability, lack of correlation between VRES generation and energy consumption, and absence of firmness in generation programs, among others, impose new power balance challenges given that electricity systems should be constantly adjusting to fluctuations in demand and generation.

Electricity generation coming from variable renewable sources can affect the design of balancing markets in different ways. First, the variability and uncertainty of wind and solar PV energy increases requirements for various ancillary services, affecting the scheduling and pricing of those services. Second, their impacts strongly depend on system conditions (demand situation, importance of VRES-E in electricity programs, scheduling regime of the other conventional generation facilities, mix of generation technologies, existing flexible generation...), which make the demand for ancillary services difficult to generalize across timescales and systems.

In this respect, the present paper aims to contribute to a better understanding of these economic consequences by evaluating the impact of VRES-E generation on balancing market requirements and costs. Due to the limited predictability and variability of VRES-E generation, SO might be required to provide significantly higher volumes of these ancillary services than in the past.

Drawing on real data for Spain for the period 1 January 2011 to 31 December 2014, the economic impact on final electricity prices of both VRES-E characteristics, variability and non-full predictability, will be analysed. The aim of this study is to assess the power system balancing costs associated with the increasing presence of intermittent production. A critical issue in power system operation is the amount of balancing and operating reserves that will be needed to keep the power system functioning securely and efficiently (Holtinen et al., 2011 and Pérez-Arriaga and Batlle, 2012). Given that the integration of variable generation in a power system depends on the properties of wind and solar PV but also on the power system into

which VRES-E is integrated, the analysis will take system characteristics in terms of flexibility and electricity demand into account.

As we demonstrate in this paper, although several factors might cause active power imbalances in electricity system, RES integration costs strongly depend on power system characteristics. The evolution of installed RES-E capacity constitutes a relevant factor. From the point of view of power system operation and management a scenario of low penetration of renewable energies in the generation mix is not the same as a scenario where renewable power is one of the main generating sources, as is the case in Spain. However, as we demonstrate in this paper, the cost associated with the integration of renewable energies depends on other aspects. Questions such as RES-E output measured in terms of power ramps or gradients over different time horizons or the availability of flexible conventional generation connected to the system are also relevant. Sudden hourly VRES-E schedules imply additional operational requirements to the system considering that enough generation has to be committed to accommodate these variations. In this respect, the present paper tries to contribute to a better understanding of these economic consequences by evaluating the impact of VRES-E generation on balancing market requirements.

The remainder of this paper is structured as follows. Section 2 provides an overview of VRES-E evolution in Spain, mainly explained by different support schemes, and its impact on system operational costs. The Spanish adjustment markets are also described in this section, with a more detailed description of the way in which the imbalance markets have evolved and functioned over time. Variables, model specification and the data used are detailed in Section 3. Estimation results are presented in Section 4. The paper ends with a final section summarising research conclusions and presenting policy and regulatory recommendations.

2. VRES-E GENERATION AND ADJUSTMENT SERVICES IN SPAIN

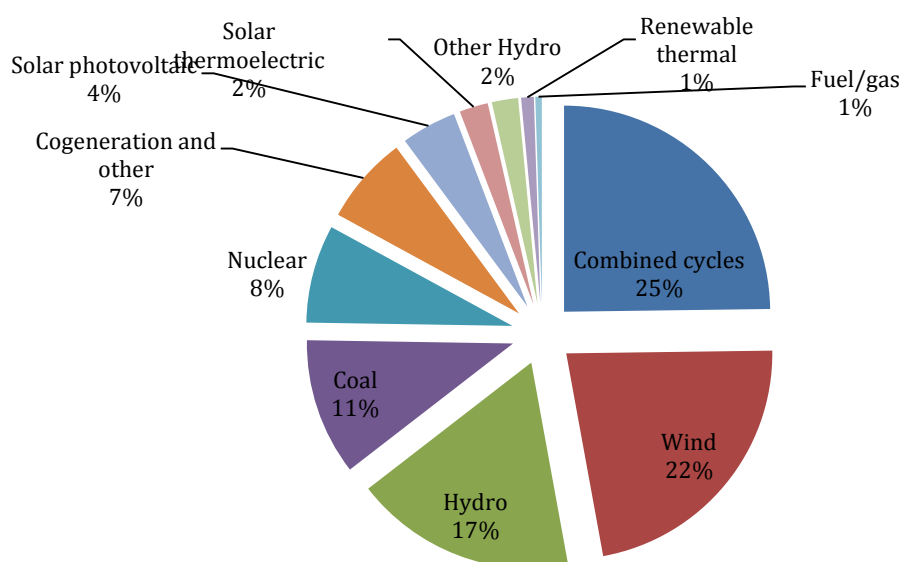
Over the last decade Spain has become a leader country with respect to the introduction of renewable energies. The rapid development of renewables in Spain was a direct outcome of national energy policies including regulatory changes focused on facilitating the grid integration of RES-E production and economic and financial incentives. Spain basically followed the “feed-in-tariff” (FIT) policy approach based on the determination of a long-term fixed price for RES-E production or fixed premium tariffs paid on top of the spot market price for electricity.

This policy¹ has encouraged, besides the country’s great renewable potential itself, investment in renewable energy technologies resulting in an increase in the RES-E

¹ Increasing concern in the government about the large increase in the associated support costs of a feed-in tariff led to the implementation of several cost-containment regulations (Mir-Artigues et al., 2015 for a detailed overview of those cost-containment mechanisms).

installed capacity. With 39,765 MW² at the end of 2014 – Spain ranked fourth in the world in terms of RES-E installed capacity. Furthermore, this impressive RES-E deployment has resulted in a diversified energy mix where a great variety of generation technologies are present (Figure 1). In addition to the high and fast growing RES-E generation penetration and the diversified power system, Spain also makes a relevant case study because of the isolated nature of its electricity system, with low interconnection capacity with neighbouring countries (France, Portugal, Morocco and Andorra). This represents additional challenges when integrating electricity generation from variable renewable electricity sources.

Figure 1: Installed power capacity³ in Spain



Spanish RES-E generation has grown from 45 TWh in 2004 to 100 TWh in 2014, with a peak in RES-E generation in 2013 when it represented 42% of total electricity demand (Figure 2). Among the different RES-E generation technologies, VRES-E generation (albeit primarily wind and solar photovoltaic power), based on sources that fluctuate during the course of any given day or season has grown until it represented 58% of total RES-E production in 2014.

Regarding demand coverage, renewable energies have continued to maintain a prominent role in the overall production of energy in the electricity system covering 42.8 % of the total consumption. Figure 3 illustrates the contribution of RES-E to national electricity consumption in the period comprised between 2011 and 2014. Electricity produced from renewable energy sources comprises the electricity generation from hydro plants (including large hydro), wind, solar photovoltaic and

² RES installed capacity and generation refers to the peninsular system and it includes cogeneration and waste treatment and excludes large hydropower (>50 MW).

³ As at 31 December 2014.

thermoelectric geothermal and renewable thermal.

Figure 2: Evolution of RES-E and VRES-E generation in Spain, 2004-2014

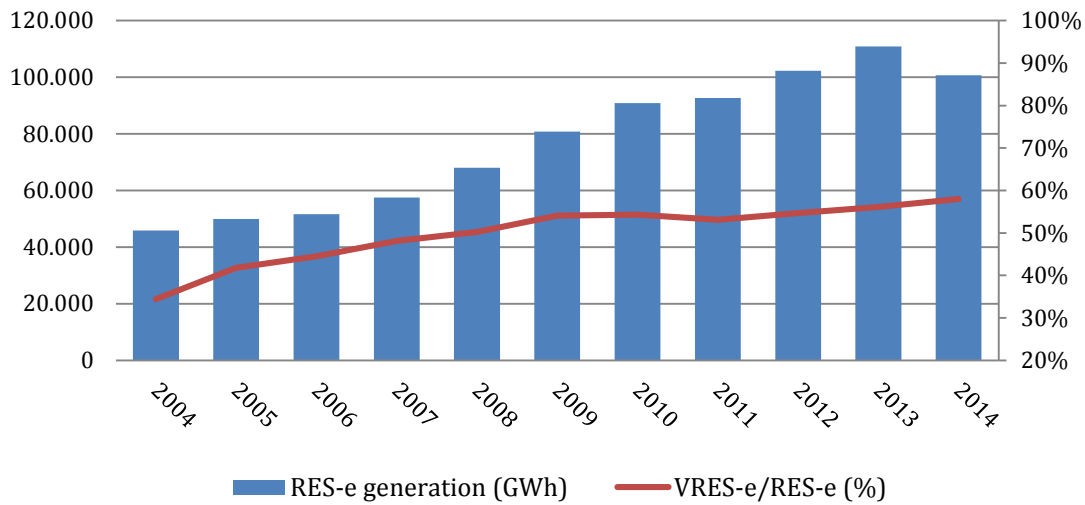
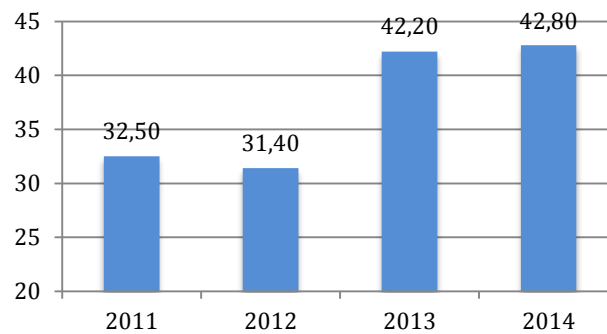


Figure 3: RES-E participation in the Spanish electricity demand coverage (%), 2011-2014



Taking a closer look at the different VRES-E technologies, wind (20.4%) and solar PV (3.1%) play a significant role in the Spanish power system. Both technologies are characterised by their intermittency, meaning that both present non-controllable variability and partial predictability, their integration having important system operation implications. VRES-E production is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable conventional power plants (Hirth et al., 2015). As can be seen in Figure 4, on the one hand, solar photovoltaic generation is characterised by a diurnal pattern, where peak production occurs in the middle of the day (around 14.00). On the other hand wind generation is more variable over time and is mostly explained by fluctuations in wind conditions – mainly speed -. Although wind power output may display some daily and seasonal characteristics, it follows much less regular patterns than does load. Although in the period comprised between 2011 and 2014 the yearly average of wind generation for each hour fluctuated between 4.9 and 7.1 TWh, with an average hourly production of 6 TWh. Wind power output tends to be higher during the night period followed by a downward ramp in wind production in the morning and a later increase from noon.

Figure 4: Hourly average wind and solar photovoltaic generation, 2011-2014

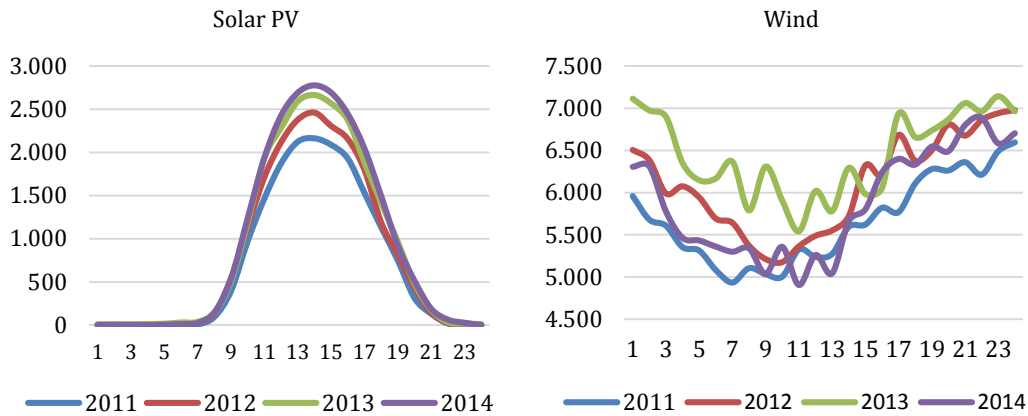
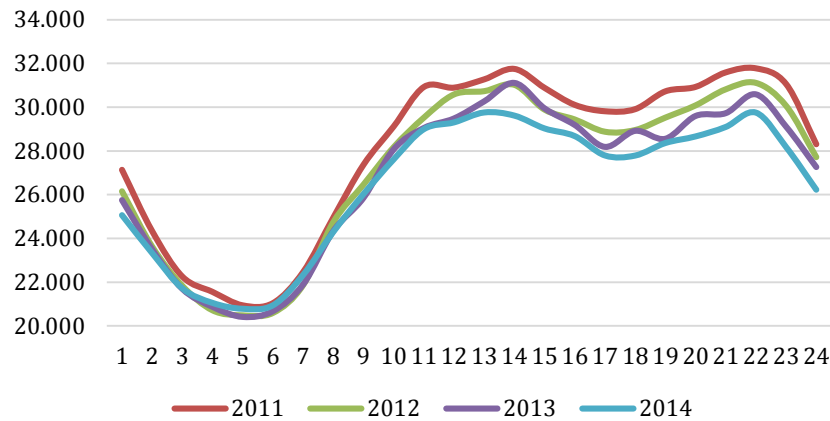


Figure 5: Hourly average load, 2011-2014



Furthermore, variable generation is not necessarily correlated with load with the consequent implications that this has in countries with relatively limited storage capacity such as Spain. Depending on the time scale considered, the load profile presents different daily, weekly, monthly, seasonal or even yearly patterns. Figure 5 shows how Spanish electrical demand varies throughout the day with peaks of demand at noon and in the early hours of the night.

Variability is not new to power systems, which must constantly balance the supply and variable demand for electricity and face all kinds of contingencies (IEA, 2009, 2011a and 2011b). From a system management perspective, several factors coming from both supply and demand variables might cause active power imbalances in an electricity system. Aspects such as unplanned contingencies in the conventional or renewable generation capacity or in the interconnection capacity, forecast errors in VRES-E generation due to its intermittent nature or load forecast errors increase the need for balancing power. However large shares of variable renewables in supply imply additional pressure on power systems, which may need increased flexibility to respond to this balancing issue. Aspects such as the availability of flexible capacities

within the electricity generation mix, interconnection capacity, storage - e.g. pumped-hydro plants - or improved load control and management empowered by smart grids are relevant to providing the required flexibility.

As the electrical system has to be in permanent equilibrium, balancing power (regulating and frequency-control power) is used to quickly restore the supply-demand balance in systems after active power imbalances arise. Adjustment services managed by the SO are responsible for adapting hourly production programmes resulting from the day-ahead market to the requirements of demand and supply deviations in real time, thus guaranteeing the above-mentioned balance and meeting the conditions of quality and safety required for the supply of electric power.

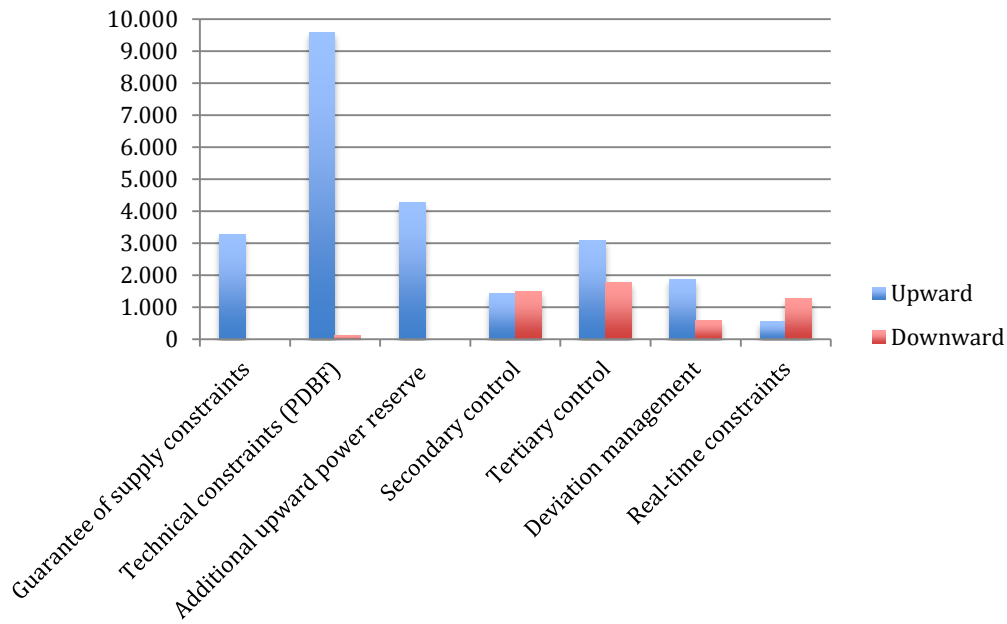
In the process of programming the generation, the operation of the system is focused on three fundamental aspects (Table 1): a) the resolution of technical restrictions identified in the programming resulting from the day-ahead and intraday markets, and from the operation itself in real-time; b) the management of the system adjustment services corresponding to the complementary services of frequency and voltage regulation and control of the transmission network; and c) the deviation management process as an essential way of guaranteeing the balance between production and demand, ensuring the availability at all times of the required regulatory reserves.

Table 1: Overview of the different system adjustment services

Main function	System Adjustment Service
SYSTEM SECURITY (Voltage, frequency, lines and transformers control)	<ul style="list-style-type: none"> • Solving technical constraints • Voltage control
SYSTEM RESERVES (Guarantee adequate reserves in the system)	<ul style="list-style-type: none"> • Additional upward power reserve • Secondary regulation (reserve)
BALANCING SERVICES (Management of regulation energies and balance in real time)	<ul style="list-style-type: none"> • Secondary regulation (activation) • Tertiary regulation • Deviation management • XB Balancing services

System adjustment services make it possible to guarantee the permanent equilibrium of the electricity system contracting the active and reactive power reserves necessary to ensure the reliable and safe operation of the electrical system. The energy managed by the system adjustment services markets in 2014 was 29.2 TWh (Figure 6), a figure 16% higher than the previous year.

Figure 6: Energy traded in the adjustment services markets, 2011-2014



The final price of electricity is determined by different market sessions held the day before delivery or even on the day of delivery as the sum of the various prices and costs associated with each of these markets. The impact of the cost of these adjustment services on final prices is presented in Table 2.

Table 2: Annual evolution of electricity final price (€/MWh) by components, 2011-2014

Concept	2010	2011	2012	2013	2014
Day-ahead and intraday market price	38.4	50.9	40.8	46.1	43.4
Adjustment services cost	3.8	3.2	4.7	5.5	5.7
Capacity payments	3.6	6.1	6.1	6.0	5.8
Final price	45.8	60.2	59.6	57.7	55.0

Although variability need not be a barrier to increased renewable energy deployment, at high levels of VRES-E market penetration a careful economic analysis of the implications in terms of system operation is required. A strong presence of intermittent renewable generation is changing the way power systems are operated and controlled (Pérez-Arriaga and Batlle, 2012). In this paper we try to contribute to the analysis of this by exploring the relationship between the operational costs of the electricity systems and VRES-E generation. The integration of larger shares of VRES-E generation (in particular wind and solar power) increases the flexibility requirements of the complementary system necessary to balance the fluctuations of variable generation. Variable renewable generation such as wind and solar PV introduce additional variability and uncertainty into the power system. In order to maintain reliable power system operation as variable energy resources provide a

larger proportion of our electric energy supply, sufficient system flexibility will be required. Although there are different links between RES-E and its associated balancing requirements⁴ (Hirth and Ziegenhagen, 2013), this paper explores the nexus between variability in VRES-E output and the consequent need for balancing power. The variability of renewable generation requires that the power system be operated with a high degree of flexibility so as to keep pace with the fluctuating net load, defined at each instant as the difference between total energy consumption and total variable renewable production.

From a system management perspective, several factors, coming from both supply and demand variables, might cause active power imbalances in electricity systems. The factors that might cause power imbalances in relation to the daily scheduled programs are varied and of different natures. From the supply side, aspects such as unplanned contingencies in the conventional and renewable generation capacity or in the interconnection capacity, or variability and forecast errors of VRES-E generation due to its intermittent nature increase the need for balancing power (Huber et al., 2014). Likewise, load forecast errors have a similar effect.

Although, power system reliability and resource adequacy are complex elements of market operations where final cost is influenced by multiple factors, in this paper we isolate and quantify the economic impact of the deployment of variable renewable energies on adjustment services. This is not an easy goal due to the complex nature of wholesale, intraday and ancillary services markets where many variables can impact on final prices and generator revenues (location, cost of raw materials, generation mix, level of demand, relevance of the electricity imbalances...). The aim of this paper is, hence, to contribute to a better understanding of the economic consequences of RES objectives on the final price paid by the consumers.

3. DATA AND EMPIRICAL STRATEGY

As has been pointed out in previous sections, deviations between scheduled energy and real time demand are addressed through ancillary services, which are mostly based on market procedures, such as secondary and tertiary reserves and imbalance management processes. Therefore, there is a direct relationship between the size of the deviation and the cost to the system of solving it. Using hourly market data for Spain for the period comprised between 1st January 2011 and 31st December 2014, the average weighted cost of system adjustment services - technical constraints,

⁴ There is a multitude of names for the different services available to restore the supply-demand balance in power systems (see Hirth and Ziegenhagen, 2013 and Rivero et al., 2011 for a comprehensive comparison of European balancing markets). This heterogeneity could be hampering the comparative analysis of balancing services across Europe. Considering that European transmission system operators are using the term “operational reserves” (ENTSO-E, 2012), in this paper we use the concept “operational costs” in a broad sense when referring to the costs associated with the provision of these services.

secondary control, tertiary control, power reserve, deviation management and real-time constraints – is used as the dependent variable in the econometric estimation.

Drawing on data for the Spanish market, the cost of operating reserves has been calculated. Operating reserves, often referred to as ancillary services, include contingency reserves – the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage – and regulation reserves – the ability to respond to small, random fluctuations around expected load – (Hummon et al., 2013).

The adjustment (or operational) cost, defined as the economic cost of the balancing mechanisms required when demand or supply deviations appear, is the price spread (Batalla-Bejerano and Trujillo-Baute, 2015) between the final electricity price and the price after the last intraday market session. Deviations between scheduled and measured energy after the intraday market are addressed through market procedures, including secondary reserve, tertiary reserve and the imbalance management process. The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments⁵ are not considered. In other words, the adjustment cost results from the aggregate of overall system adjustment services managed by the SO – technical and real-time constraints, power reserve, secondary and tertiary control band and deviation management process services.

Taking into account the above considerations, and bearing in mind that the final electricity price is the sum of the different prices and costs associated with each of the markets that integrate the power system, the hourly weighted average *adjustment service cost* is obtained as follows:

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \quad (1)$$

being:

- ASC_t : Weighted average adjustment service cost (expressed in €/MWh)
- FP_t : Weighted average final price (expressed in €/MWh)
- $DAMP_t$: Day-ahead market price (expressed in €/MWh)
- IMP_t : Weighted average intraday market price (expressed in €/MWh)
- CP_t : Weighted average capacity payments (expressed in €/MWh)

⁵ Capacity payments are the regulated payments to finance the medium and long-term power capacity services supplied by the generation facilities to the electricity system. Given that they are not directly related to the procurement of flexibility in the system, this cost is not included.

When assessing the determinant factors behind power system balancing costs the following variables are used:

VRES-E generation (VRES G)

The introduction of large amounts of variable and uncertain power sources, such as wind power, into the electricity grid presents a number of challenges for system operations. One issue involves the uncertainty associated with scheduling power that wind will supply in future timeframes (Hodge et al., 2012).

Although wind and solar photovoltaic power output may display some daily and seasonal characteristics and the forecast models have improved significantly over the past years, electricity generation from wind and solar sources is uncertain, implying unforeseen deviations from scheduled electricity programs. The greater range of variability experienced even by aggregations of wind and solar photovoltaic power plants also adds to the difficulty of forecasting output on the day-ahead timescale. VRES-E generation imbalances imply economic costs given that their correction entails the use of balancing power. Deviations between scheduled and consumed electricity are addressed through ancillary services based, in most instances, on market procedures, such as secondary and tertiary reserves, and the imbalance management process, and so there is a direct relationship between the size of the deviation and the cost incurred by the system in resolving it. Therefore, there is a direct relationship between VRES-E generation and the expected total costs in terms of adjustment services.

Given that, as shown in Figure 7, wind and solar PV production seem to be negatively correlated presenting different –potentially complementary- diurnal patterns with different periods of high (low) output, the variable VRES-E generation (*VRES G*) is defined on an aggregate basis. In this way, *VRES G* is defined as:

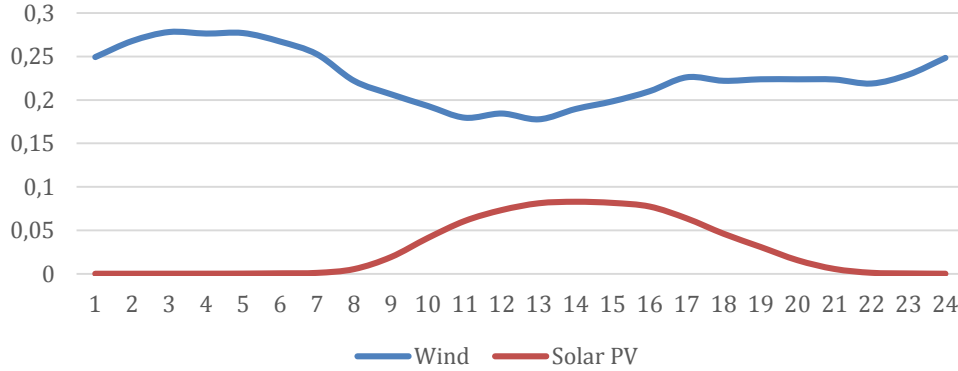
$$VRES G_t = W_t + SPV_t \quad (2)$$

being:

W_t : Wind production in the Daily Base Operating Schedule (PDBF by its acronym in Spanish) (in relative terms over hourly demand).

SPV_t : Solar photovoltaic production in the PDBF (in relative terms over hourly demand).

Figure 7: Hourly average wind and solar photovoltaic generation, 2011-2014



VRES-E ramp (VRES R)

Even with perfect forecasting for VRES-E generation, *ceteris paribus* the consequence for electricity systems of increasing variability in the RES-E output constitutes an additional source of stress on system operation (Huber et al., 2014). In this sense, some studies (Eurelectric, 2010) consider that another relevant factor besides the power production profile is power ramps or gradients over different time horizons. Whilst traditional variability of demand or load has always required a certain amount of flexibility, power ramps will introduce a step change in the way electrical systems are operated. Sudden hourly VRES-E schedules imply additional operational requirements to the system considering that sufficient generation has to be committed to accommodate these variations. In this paper, variable renewable generation ramps (*VRES R*) have been defined as the change of power in a given time interval – in our case from hour to hour -:

$$VRES R_t = VRES G_t - VRES G_{t-1} \quad (3)$$

Changes in operational requirements due to *VRES R* normally take place in the morning and early evening hours. As illustrated in Figure 7, the ramp up in solar generation in the mid-morning and the solar ramp down in early evening can increase the energy regulation requirements of the system. At the same time solar and wind ramps do not necessarily happen at the same moment. In many hours, the combination of solar and wind resources can lessen operational requirements because solar resources are ramping up when wind resources are ramping down, and vice-versa, the aggregated variability of both technologies together being less than each are individually. Given that and considering that the geographic diversity and dispersion of wind and solar photovoltaic output reduces aggregate variability over large

geographic areas, the ramp variable has been defined on an aggregate basis. As in the case of the variable corresponding to renewable generation, the gradients of renewable production are expressed in relative terms on the hourly demand. At the same time, data series are presented in absolute terms

Conventional generation flexibility (CGF)

In order to maintain reliable power system operation as variable energy resources provide a larger proportion of our electric energy supply, sufficient system flexibility will be required. Operational flexibility is an important property of electric power systems. The term flexibility is widely used in the context of power systems although at times without a proper definition. The role of operational flexibility for the transition from existing power systems, many of them based on fossil fuels, towards power systems effectively accommodating high shares of VRES-E has been widely recognized. Integrating large shares of VRES-E generation, in particular wind and solar PV, can lead to a sharp increase in flexibility requirements for the complementary power system (Huber et al., 2014). In the case of Spain, this complementary or conventional system is mainly composed of combined cycle, coal, fuel oil and gas generation, and these have to balance the fluctuations of variable generation.

Categorizing different types of operational flexibility constitutes a complex question (Ulbig and Andersson, 2012) due to the existence of different flexibility metrics. In this paper, as the flexibility strongly depends on the total contribution of wind and solar energy to hourly electricity consumption and load evolution, Conventional Generation Flexibility (CGF) from flexible sources is defined in terms of power portfolio connected to the system able to provide balancing energy to the system. Nuclear and hydroelectric generation are considered to be inflexible given that these generation technologies are currently operated in a base-load mode.

The presence of intermittent generation in power systems with priority of dispatch together with a large quantity of inflexible conventional generation alters and reduces the net load to be satisfied with flexible generation able to start up and shut down generation as the system requires. Sudden and massive requests for power, in terms of power ramps, create new requirements for conventional generators. In this paper, we have defined conventional generation from flexible sources (*CGF*) as the production in the PDBF from flexible technologies, such as coal, fuel oil, and gas (open and combined cycles):

$$CGF_h = COAL_t + F\&G_t + CCGT_t \quad (3)$$

being:

- COAL_t*: Coal production in the PDBF (in relative terms over hourly demand).
- F&G_t*: Fuel oil and gas production in the PDBF (in relative terms over hourly demand).
- CCGT_t*: Combined cycle production in the PDBF (in relative terms over hourly demand).

Given that these flexible generation technologies have different characteristics – costs and time required to start, ramping limits – which determine their capacity to start up quickly and increase their production when the system requires, the importance of the combined cycles in terms of system operation will be assessed independently (*CCGT* variable) from the rest of flexible generation technologies (*OTHERS* variable). Although pumped storage has been identified as the most responsive technology (Eurelectric, 2010) with the fastest load gradient, combined cycle technology is the most important back-up technology able to adjust its generation to provide power when it is most needed. With more than 25 TW of installed capacity – 24.8% of total peninsular installed capacity, as at 31st December 2014-, CCGTs are normally particularly suited to adjusting their output to net load-following operations. At present, CCGT allows SO to deal with both upward and downward VRES-E ramps that may reach 2,000 MWh from hour to hour.

Regarding the econometric approach, using hourly market data for Spain over the period comprised between the 1st January 2011 and the 30th December 2014, a time series regression model controlling for seasonality was constructed. The econometric estimation uses the average weighted cost of system adjustment services (*ASC*) as the dependent variable. This variable, obtained as a price spread, includes the economic cost associated with all adjustment services - technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints -. VRES-E output (*VRES G*), VRES-E gradients or ramps (*VRES R*) and conventional power generation (*CGF*) are used as the main explanatory variables.

In addition, as in other electricity market price studies, we have introduced an autoregressive component to capture the dynamic effects on the adjustment costs. Two additional variables were introduced as control variables. First, to control for consumption patterns in peak and off-peak demand hours we introduced a temporary variable (*Peak Demand (PD)*). As electricity demand varies through the day, this dummy variable (=1 if a peak demand hour) was introduced in the specification of the model in order to address aspects related to seasonality. Second, as VRES-E generation is not the only source of variation in a power system, a second control variable was introduced to control for other possible power imbalances. The demand for electricity, or load, also varies, and the power system was designed to handle that uncertainty. After intraday market gate closure, SO have to adjust the resulting program to any demand and supply deviations from that scheduled. The required balancing energy to handle electricity deviations coming after intraday gate closure

(*Real Demand Adjustment (RDA)*) was included in the model specification. As in the case of the rest of variables, *RDA* is expressed in relative terms on hourly demand.

Table 3 presents the descriptive statistics of the variables used.

Table 3: Summary statistics

Variable	Obs.	Mean	Std. Dev.	Min	Max
<i>GAC</i>	35039	4.8333	3.7475	0	93.86
<i>VRES G</i>	35039	0.2551	0.1137	9.09E-03	0.7121
<i>VRES R</i>	35039	0.0126	0.0109	2.95E-06	0.3334
<i>CGF</i>	35039	0.2184	0.1151	0.0087	0.5234
<i>CCGT</i>	35039	0.0731	0.0528	1.00E-05	0.3196
<i>OTHERS</i>	35039	0.1426	0.0889	0.0074	0.4625
<i>RDA</i>	35039	0.0349	0.0289	2.59E-10	0.2480
<i>PD</i>	35039	0.4166	0.4930	0	1

Before presenting the time series regression models constructed for the analysis of the impact of RES-E integration on adjustment costs, it should be pointed out that a stationary time series analysis was carried out. We performed two tests. First, the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) under the null hypothesis of a unit root, and second the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) tests (Kwiatkowski, et al., 1992) under the null hypothesis of stationarity. Both tests⁶ confirm that the series are stationary in logarithms, so we estimate the models using all series in logarithms. In addition to the time series properties of the variables, a deep outlier analysis was carried out, which confirmed the existence of extreme values⁷. Given the confirmed validity of outlier observations and the dynamic nature of the model, all data points should be maintained. Thus, to alleviate the effects of the outliers we carried out a quantile regression on the median⁸.

With all these considerations, the model specification is defined in the following equation:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 VRES G_t + \alpha_3 VRES R_t + \alpha_4 CGF_t + \alpha_5 RDA_t + \alpha_5 PD_t + \varepsilon_t \quad (4)$$

⁶ The results for the ADF and KPSS tests are available upon request.

⁷ As an additional test of time series, we used the blocked adaptive computationally efficient outlier nominators (BACON) algorithm proposed by Billor et al. (2000) and further developed by Weber (2010) to detect outliers in our multivariate data. The results for the BACON test – available upon request - confirm the existence of extreme values of the observable variables.

⁸ The quantile approach is not as sensitive as the least squares approach to outliers because it does not give much weight to them (at the median it gives symmetric weights to positive and negative residuals), but at the same time, unlike robust estimation, quantile estimation does not sacrifice observations with relevant information.

As in the least squares estimation of dynamic models, it is evident that the unobserved initial values of the dynamic process also induce a bias in the context of quantile regression. Instrumental variable methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions. These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the included regressor but are uncorrelated with the innovations. Thus, valid instruments are available from inside the model and these can be used to estimate the parameters of interest employing instrumental variable methods. In this paper the construction of instruments is carried out using values of the dependent variable lagged two periods and the lag of the exogenous variables, which are all independent of ε_t , to perform estimations using the instrumental variable quantile regression method.

4. RESULTS

In order to evaluate the effects of VRES-E generation (*VRES G*), VRES-E variability (*VRES R*), and conventional generation flexibility (*CGF*) on adjustment costs (*ASC*) we performed five sets of estimations based on equation 4 as presented in the previous section with different groups of control variables. We first estimated the impact of VRES-E on ASC including only the additional controls (*RDA and PD*), these results are reported in column (1) of Table 4. In the second set of estimations - column (2) - we also included the ramp or gradient of VRES-E (*VRES R*) to test if along with the penetration of VRES-E there is also a relevant intensity of sudden changes in consecutive hours. In the third set of estimations –column (3) – we introduce the penetration of aggregated conventional flexibility (*CGF*) in order to evaluate its potential in reducing adjustment costs. Finally, in the last two sets of estimations we evaluate the contribution of the most flexible technology (*CCGT*), by first introducing only CCGT –column (4) – and then adding the other sources of flexibility (*OTHERS*) –column (5).

Overall, the results of the estimations support a significant and positive effect of VRES-E generation on adjustment services costs. The short-run elasticity of VRES-E ranges between 0.01 and 0.05 depending on the group of control variables, being consistently around 0.02 – 0.03 with the full set of controls. In addition, the results confirm that, along with the penetration of VRES-E, adjustment services costs increase with the intensity of VRES-E generation changes in consecutive hours, the ramp (*VRES R*). In all estimations the short-run elasticity of the *VRES R* is 0.01. The magnitude of this parameter seems to be capturing, as we hypothesize from Figure 6, that the interaction between wind and photovoltaic ramping hours are complementing each other, and hence exerting a relatively small effect on the system adjustment services costs.

The reduction of adjustment services costs effects of conventional flexible sources are evaluated in the estimations presented in columns (3) to (5). When considering all the flexible generation together, from an aggregated perspective, the short-run elasticity is 0.03 – see column (3). When CCGT, as the most flexible technology, is separated from the rest (*OTHERS*) the results show that CCGT elasticity is 0.02 and for the rest it is 0.003 – see columns (4) and (5). Therefore, the results confirm that conventional flexible generation decreases adjustment services costs and that the CCGT cost saving effect is greater than it is in the case of other technologies.

Table 4: Impacts on the adjustment services costs

	(1)	(2)	(3)	(4)	(5)
<i>L.ar</i>	0.8978*** (0.003)	0.8949*** (0.004)	0.8798*** (0.004)	0.8783*** (0.003)	0.8786*** (0.003)
<i>VRES G</i>	0.0482*** (0.004)	0.0465*** (0.005)	0.0123*** (0.006)	0.0298*** (0.004)	0.0268*** (0.004)
<i>VRES R</i>		0.0129*** (0.002)	0.0113*** (0.002)	0.0123*** (0.001)	0.0121*** (0.001)
<i>CGF</i>			-0.0355*** (0.002)		
<i>CCGT</i>				-0.0190*** (0.001)	-0.0179*** (0.001)
<i>OTHERS</i>					-0.0028*** (0.001)
<i>RDA</i>	0.0097*** (0.000)	0.0095*** (0.000)	0.0089*** (0.000)	0.0090*** (0.000)	0.0089*** (0.000)
<i>PD</i>	0.0001*** (0.000)	0.0020*** (0.001)	0.0056*** (0.001)	0.0058*** (0.002)	0.0065*** (0.001)
<i>Constant</i>	0.2577*** (0.002)	0.3192*** (0.015)	0.2134*** (0.002)	0.2506*** (0.002)	0.2409*** (0.003)
<i>Observations</i>	35033	35033	35033	35033	35033
<i>Pseudo R2</i>	0.7654	0.8191	0.8368	0.8678	0.8752

Note: QRIV results with weighted bootstrap standard errors in parentheses*** p<0.01, ** p<0.05, * p<0.1

The results for the additional control variables, *RDA* and *PD*, are consistent across the different sets of estimations and in line with expectations. Regarding the *RDA*, our results confirm the finding of previous studies (see Batalla and Trujillo-Baute, 2015) where the demand adjustments are considered to be a factor increasing adjustment services costs. Likewise, the peak hour control captures the hourly consumption pattern during the day, and shows that during peak hours adjustment services costs are higher. Both control variables are significant, and in the context of this study, are important for guaranteeing the proper estimation of the parameters of interest.

In order to provide additional insights, Table 6 summarizes the relevant long-run elasticity from the analysis performed. On the one hand, we observe that if there were an increase of 10% in *VRES-E* penetration with the same flexible generation, in the long run the system would face an increase in the adjustment cost of 2.2%. On the other hand, *ceteris paribus*, if the penetration of aggregated flexible generation were increased by 10% a saving would be made of 2.9% on adjustment services costs. These results highlight the importance of the interaction – counterbalance effects – between *VRES G* and *CGF* from the system perspective, and consequently on the adjustment services costs.

Table 6: Long run elasticities

	Elasticity	Direction of the effect
<i>VRES G</i>	0.22	↑
<i>VRES R</i>	0.09	↑
<i>CCGT</i>	0.14	↓
<i>OTHERS</i>	0.02	↓
<i>CGF</i>	0.29	↓

Finally, a highly interesting result comes to light with the comparison of the long run elasticity between generation from *CCGT* and the other sources of flexibility. While a 10% increase in *CCGT* penetration would lead to a decrease of 1.4% in adjustment services costs, an equivalent increase of the other conventional sources would imply savings of only 0.2%.

5. CONCLUSIONS

At the end of 2013, renewable energy sources covered approximately 14.7% of Spanish final energy consumption. Given that by the year 2020 Spain is required to meet the European target of covering 20% of the energy demand using renewable sources, and that the onus of achieving this goal lies heavily on the electricity sector, further increases in *RES-E* are expected in order to comply with the approved European Commission initiatives. The power system integration of this *RES-E* capacity impacts, as we demonstrate in this paper, on system operation, the final cost depending on multiple factors.

The penetration of *RES-E* generation – especially wind and photovoltaic power – in Spain has developed to levels that were unthinkable a decade ago. Technical improvements coming from both *RES-E* power producers (fault-ride-through

capabilities, visibility and controllability of RES-E power, reactive power control...) and the system operators (specific control centre for RES energies, forecasting tools...) are behind this success in quantitative terms. Nevertheless, given that RES-E market integration is crucial, a comparative quantification of the overall system-related costs and benefits of the increase in RES-E is required.

The variability and uncertainty associated with VRES-E generation have a number of impacts on power systems. Real-time deviations in renewable power generation, explained by its non-full predictability, affect daily markets and result in higher balancing costs and greater fluctuation in the reserve requirements. At the same time, the variability of renewable electricity production, with an availability ratio - production in relation to the installed capacity - ranging between 5% and 70%, implies the need for flexible power capable of covering those moments when renewable generation is not available. As expected, the results point toward a significant effect of VRES-E integration on system costs. According to our estimates, both VRES-E attributes – uncertainty and variability – exert a positive and significant effect on adjustment costs, their respective intensities being statistically different, always higher in the case of the variable responsible for capturing the uncertainty derived from the non-full predictability of VRES-E generation. These results highlight the relevance of forecast errors when explaining integration costs. At the same time, power ramps introduce a step change in the way electrical systems are operated, exerting a positive impact on system costs. Variability implies additional operational requirements to the power system considering that additional generation has to be committed to accommodate these variations

From the broader perspective of energy policy and sector regulation, a key question when evaluating the evolution of RES integration refers to the availability of sufficient operational flexibility. As demonstrated, this additional flexibility, a necessary precondition for the grid integration of large shares of VRES-E power, is provided by conventional generation. The system integration of VRES-E generation requires flexible technologies able to modulate their production to provide coverage for demand. In an isolated country such as Spain, with low cross-border interconnection capacity, the availability of flexible plants acquires increasing importance. Power plants able to work on a part-time operational schedule and ready to provide the upward/downward power are required by the system. Among these flexible technologies, the results indicate the importance of combined cycles. CCGT allows the SO to deal with sudden up and down VRES ramps at the most competitive cost in comparison to other flexible technologies. In Spain, this last issue is of great importance. Although the system has more than 25 TW of installed capacity using combined cycles, the fall in electricity demand as well as a growing share of the renewable in the demand means that a very small part of this power is connected to the network when the system requires it. The low availability of mid-merit power technologies able to change their output dynamically in contrast to baseload

conventional technologies, as we demonstrate in this paper, has its economic consequences in terms of adjustment costs.

Minimising total system costs at high shares of VRES-E requires a strategic approach to adapting and transforming the energy system as a whole. To meet this goal, all countries where VRES-E is becoming a mainstream part of the electricity mix should make better use of existing flexibility by optimising system and market operations. Sending the correct signals to participants, to encourage them to look for the optimum technical solutions, entails an in-depth knowledge of cost drivers as provided by this paper. Success in adapting the power system lies in analyses able to provide clearer insights into the costs and impacts associated with incorporating renewable energy into electricity networks.

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