Short-term effects of PV integration on global welfare and CO_2 emissions. An application to the Iberian electricity market

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Abstract.

This work analyses the effect on the daily electricity market of the authorisation of 3,909 MW of new photovoltaic (PV) power in Spain in 2017 –as a contribution to the EU environmental objectives for 2030. To estimate the impact of this additional offer, we use real data from the supply and demand curves of the Iberian (Spain and Portugal) daily electricity market. Our data is available for all the hours of the full year between August 1, 2016 and July 31, 2017. In this period, more than 800 agents have participated in the market, generating more than 15 million operations. In order to calculate the new supply function for each hour, the hourly production of these new facilities is added to the offer at zero price, since their marginal costs are very close to zeroand correspond to the offers that are being made by the current PV bidders. By using static and dynamic (*multilevel*) analyses, the variations of prices, quantities, emissions and surpluses of buyers and sellers are calculated. As the economic theory foresees, the new supply curve causes a decrease in average prices of 2.7 €/MWh in daylight hours(or 1.5€/MWh considering all the hours of the year), and an8% reduction in the income of the PV plants currently in operation (incumbents). The substitution of combined cycle energy (the technology expulsed) by PV energy brings about a saving of 2.2 million Mt of $CO_{2\,eq}$. In terms of economic welfare, the incorporation of PV power produces an increase in the total surplus of about 300 M€ each year.

Keywords. *Economic Welfare; Surplus sharing; Competitive markets; Photovoltaic; Renewable support policy; $C0_2$ emissions;*

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1. Introduction.

The aim towards a low-carbon economy worldwide helps understand the important changes faced by the electricity markets. The growing role of renewable energy sources (RES), the improvements in energy efficiency and the transport electrification are among the most important goals to achieve. These changes require important investments in electricity generation, transmission, and distribution; an investment effort that has to be compatible with the final challenge of obtaining affordable electricity for households and industries (Erbach, 2016).

The EU (2013) sets ambitious environmental targets in the document *Green Paper: A 2030 framework for climate and energy policies*, where, among other matters, it establishes a minimum RES share of 27% at the end of the period. Although there are several mechanisms to support RES, electricity auctions are becoming more popular in the EU Member States because they offer some advantages, such as the control of subsidies, that can be used to promote specific technologies, depending on their maturity and potential (García-Redondo and Román-Collado, 2016; Newbery et al., 2018). Some other papers provide sonorous conclusions about the RES promotion through a Feed-in-Tariff (FiT) system; for example, Chatri et al. (2018) show, for Malaysia, that if additional revenues from subsidy reforms are re-allocated in order to finance the FiT framework, the production of renewable energies within the power generation sector gains weight.

Spain stands out among EU Member States. The importance of RES in this country has been largely highlighted by Ciarreta and Espinosa (2010a; 2010b) and Bianco et al. (2019). A new frame regulation induced an important increase in RES production between 2007 and 2013 (*Official State Bulletin* (BOE, 2007)). In 2013, the share of RES in the Spanish electricity market was around 57% (Ciarreta et al. 2014; 2017). From then, no relevant changes in RES participation in the pool occurred until 2017 when, through a public auction procedure, the construction of 3,909 MW of new photovoltaic (PV) power and of 1,128 MW of additional wind power was authorised.

Economic theory, through comparative static analysis, enables us foresee the effects of a rightward shift of the supply curve in the short-run. Firstly, a change is expected that reduces the equilibrium price of the electricity market and increases the equilibrium quantity. The magnitude of these changes will depend on the elasticity of the demand and supply curves. Secondly, these changes can be analysed from an environmental point of view, considering the effects on CO_2 emissions. Thirdly, the changes in the electricity market'sequilibrium can also be analysed from a welfare point of view. The shift of the supply curve to the right will provoke a change in the buyer and seller surpluses, providing us with information about the impact on social welfare (total net surplus). Economic theory tells us about the importance of distinguishing the difference between the concepts of surplus and profit. Concretely, the producer surplus shows (in the short term) the difference between revenues and variable costs while profit indicates the difference between revenues and total costs. Therefore, a positive seller surplus (or contribution margin) will not necessarily imply a positive profit.

The aim of this paper is the analysis of the economic and environmental impact produced by the incorporation of the new PV generation authorised into the Spanish wholesale market in 2017, such as the effects on equilibrium prices and quantities, the changes in the buyer and seller surpluses and CO_2 emissions. The results will allow us to provide some energy policy recommendations.

Some previous research literature has analysed the wholesale electricity market based on estimations. Thesepapers provide estimates of the effects that some policy measures have had on the spot market prices. By using an estimation of a complete system of hourly demand, Bigerna and Bollino (2016) have derived optimal zonal prices in the day-ahead Italian electricity market. Gelabert et al. (2011) model daily electricity prices and study the effects that the introduction of renewable electricity and cogeneration have had on the wholesale electricity prices in Spain Similarly, Sorknæs et al. (2019), using an energy system model for Denmark, found that regardless of the renewable electricity source, the price decreases as the amount of energy produced increases.

Unlike these previous papers which make priori assumptions about the wholesale electricity market, other empirical analyses look for an understanding of the real market structure. In general, these studies focus on the possible existence of market power on the supply side. For example, the importance of the institutional and structural features of the Californian wholesale electricity market is highlighted by Joskow and Kahn (2002), who conclude that this is a non-competitive market where the suppliers exercise a power market. Genc (2016) analyses the Ontario wholesale electricity market using some market power measures, such as the Lerner Index and the Residual Supplier Index, to estimate the price elasticity of demand during peak hours of days, seasons and years. De Frutos and Fabra (2012) analyse the impact on equilibrium outcomes of covenant commitments among electricity producers in an oligopolistic model that reflects important institutional and structural features of the electricity market. Sensfuß et al. (2008) analyse the impact of privileged renewable electricity generation on the German electricity market, concretely, on spot market prices. Other studies which estimate the effect of renewable electricity generation on German spot market prices are Neubarth et al.'s (2006) and Bode's (2006).

Complementary to the above, there are other research papers where the wholesale electricity market is analysed based on real-time market information on prices and purchase and sale bids. The analysis of the structure of locational marginal prices (node prices) in day-ahead and real-time wholesale electricity markets has also been taken into consideration (Cui et al. 2018). In addition, Zarnikau et al. (2019), applying a regression-based approach to a newly developed sample of over 60,000 hourly observations from the Texan market, conclude that real-time energy prices are impacted by day-ahead prices and forecasting errors, and suggest that a greater trading efficiency may be achieved by improving forecast accuracy. Mayer and Trück (2018) analyse the wholesale electricity spot prices around the world and conclude that electricity markets organised as day-ahead markets exhibit a significantly lower overall price variation compared to markets based mainly on real-time trading.

A field in which there is a lack of literature is that of the economic analysis of buyer and seller surpluses in the wholesale electricity market. From the seller's perspective, different aspects have been analysed. Bajo-Buenestado (2017) focuses on the welfare consequences of introducing capacity compensation payments,concluding that they are more beneficial for consumers in a perfectly competitive market than in the presence of some market power. Bhattacharya et al. (2017) develop an applied-theoretic model and perform some simulations to analyse the welfare effects of the introduction of Renewable Portfolio Standards (RPS). These authors conclude that, in general, consumers with a relatively stronger preference for green power are likely to gain from the RPS policy. Sauma and Oren (2019) apply a theoretical framework to analyse the incentives that generation firms have to support long-term transmission investments and conclude that in a two-node network, the net exporter generation firm has the correct incentives to increase the transmission capacity incrementally up to a certain point. From the buyer's perspective, Janda (2018) analyses the welfare consequences of introducing PV energy in the electricity market of the Slovak Republic, concluding that although there is a spot price reduction attributable to the PV penetration, the effects do not outweigh the costs of the support scheme, and therefore a consumer loss is finally produced.

Related to the Spanish case, some research papers have analysed the introduction of RES in the Spanish wholesale market. Specifically, Gelabert et al. (2011) conclude that a marginal increase of 1 GWh of electricity production using renewables and cogeneration is associated with a reduction of almost 2 € per MWh in electricity prices –this work is carried out using data from 2005 to 2010, a period in which the regulation and behaviour of renewable producers was not stable in Spain. More recently, based on the bids of all the agents in the Spanish pool, Ciarreta et al. (2017) replicate the equilibrium situation in the electricity market during 2002-2013 and identify the possible changes in the bidding strategies of electricity producers after the introduction of RES. These authors conclude that the introduction of RES made the generators' behaviour more competitive in the short-run. Another recent analysis (for the period 2002-2017) of the Spanish case shows that, although the phasing out of the FiT mechanism reduces regulatory costs, it also limits renewable participation in the electricity market, leading to an increase in electricity prices and emissions (Espinosa and Pizarro-Irizar, 2018). Bianco et al. (2019) conclude that to complement intermittent RES and ensure the security of supply in the wholesale electricity market, the use of Combined Cycles Gas Turbines (CCGTs) has been improved, avoiding a larger diminishing of Green House Gas (GHG) emissions.

The novelty of this paper is twofold. Firstly, the analysis is based on real hourly data. The OMIE data that we process provides us information about the purchase and sale bids of the daily electricity market. Data is available for all the hours of a full year (from August 1, 2016, to July 31, 2017). Secondly, the short-run economic and environmental impacts of the positive supply shock produced by the new PV power in the Spanish wholesale electricity market based on the real hourly data are seen, such as the effects on equilibrium prices and quantities, buyer and seller surpluses and CO_2 emissions without the need to estimate or simulate any explicit model.

The paper is structured as follows. Section 2 offers some relevant notes on the current situation in the wholesale Spanish electricity market. Section 3 describes the data and the methodology proposed for estimating the effects on the Iberian market of the new PV power. In Section 4, the results of the empirical and econometric analysis are presented. Finally, Section 5 provides the main conclusions and policy recommendations.

2. The Spanish electricity industry. The current situation.

The Spanish electricity industry was structured as a vertically integrated monopoly from its creation in the last decade of the nineteenth century. Companies in the sector developed activities of the generation, transmission, distribution and commercialisation of electricity in their respective territories. The entry into force of Directive 96/92/EC (European Parliament, 2004) obliged the liberalisation of the electricity market in the European Union, requiring the separation of activities in which competition makes sense (generation and commercialisation) from those related to the network, which must be regulated given their nature of a natural monopoly. This Directive was then transposed into Spanish legislation, giving rise to the Law 54/1997 on the Electricity Sector (*BOE*, 1997).

Nowadays, the wholesale electricity market in the Iberian Peninsula is organised through the market operator OMIE (*OMI-Polo Español S.A., Operador del Mercado Ibérico de Energía*), which is regulated by the Law 24/2013 of the Electricity Sector (*BOE, 2013*). Its functions were previously defined, in the Decree 2019/1997 (*BOE, 1997*), which also set up and regulated the electricity generation market. In this market, the production companies, on the one hand, and the commercial companies and large customers, on the other hand, formulate their energy offers and demands respectively for each hour of the following day. This process involves more than 800 agents and generates nearly 15 million operations per year. In 2018, the energy distributed in the peninsular market reached 254 TWh and almost 30 million supply points, with a maximum peak powerdemand of 41 GW (*Red Eléctrica Española* (*REE*), 2019).

The price-setting process results from the matching of the offer and demand bids formulated by the agents for each of the 24 hours of the following day (day-ahead market), although 6 auctions are held throughout the day to adjust for possible variations in demand as well as possible interruptions of generating groups (this is the intraday or real-time market). The intraday market has a small effect on the final price paid by consumers. Thus, the extra cost that this market represents in the electricity hourly price in Spain has an average annual value of 0.004 € and a standard deviation of 0.07 €, which represents the negligible value of 0.01% of the price. From our point of view, integrating the intraday market in our analysis would add complexity without producing significant changes in our results, so we have chosen to analyse only the daily (or day-ahead) market, which is the one where the bulk of the electricity is negotiated. The day-ahead market represents a marginal system; that is, the price offered for the last unit incorporated into the market will serve to remunerate all participating generators.

Table 1. Installed power and energy by technology in Spain. 2018.

	Installed Power		Energy	
	MW	%	GWh	%
Combined Cycle	24948	25.2	33648	13.6
Wind	22922	23.2	47508	19.1
Hydro	20358	20.6	20695	8.3
Coal	9536	9.6	42422	17.1
Nuclear	7117	7.2	55540	22.4
Cogeneration	5818	5.9	28175	11.3
Solar PV	4439	4.5	8000	3.2
Solar thermal	2304	2.3	5348	2.2
Other renewables	852	0.9	3599	1.5
Waste	582	0.6	3187	1.3
Fuel	0	0	0	0
Total	98877	100	248122	100

Source: CNMC (2019)

While nuclear and renewable generators typically present a price-taker behaviour (they offer all their production at zero price in accordance with their marginal costs in the short term), thermal groups (combined cycles and coal-fired power plants) make simple offers (based on their marginal costs) and, at times, complex offers. The offers with complex conditions are regulated by the 30th operating rule of OMIE (*BOE*, 2018), which provides three types of conditions: the minimum income, gradients and the indivisibility condition. These complex conditions are associated with the existence of quasi-fixed factors (Filipini, 1996).

Once an equilibrium price is obtained from the matching process between demand and supply (with complex conditions) bids, other components (extra-costs) are added to that price, such as those associated with the System Operator, the interruptibility service, the power guarantee and technical restrictions. In particular, the process of technical restrictions allows the System Operator to order the entry into the market of higher-price generators in order to guarantee the capacityand security of the network. The extra-price paid does not apply to the rest of the generators, being distributed, like the rest of components, as an additional cost to all the energy exchanged. The modelling of these constraints requires a deep knowledge of the network (Roldan et al., 2017) and this does not contribute much to the objective of this research. So, for the sake of simplicity, the equilibrium without considering technical constraints is considered to be our market outcome.

The Spanish electricity sector is undergoing major changes, both on the supply side (closure of coal and nuclear power plants, CO_2 emissions taxes, penetration of renewables, etc.) and on the demand side (installation of batteries for energy storage, demand response through the use of smart meters, etc.). All these changes are included in the NECPs (Integrated National Energy and Climate Plans) monitored by the European Commission, and in the Integrated National Energy and Climate Plan 2021-2030 (PNIEC), which indicates the specific dates of application of each NECPs initiative. The plan contemplates increasing the share of renewables to 42%, incorporating a power of 30,000 MW in this period (*Ministerio para la Transición Ecológica*, 2019). During 2017, through a public auction procedure, the construction of 3,909 MW of new photovoltaic (PV) power and of 1,128 MW of additional wind power was authorised. This increase in the power installed will produce in the next years a shift in the hourly supply curve which will reduce equilibrium prices and will displace (ceteris paribus) other conventional technologies out of the market (merit-order effect), with the consequent reduction in CO_2 emissions. While wind production modelling is relatively complicated, PV production is quite predictable, it being possible to calculate the new hourly generation and, therefore, the new supply functions. The commitment of the Spanish Government is fully justified, as it is the European country with the highest irradiation (Figure 1).

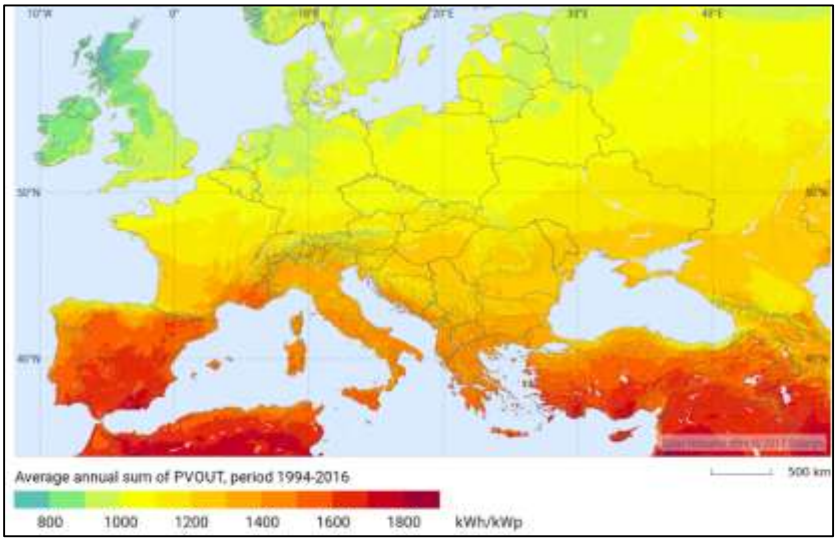


Figure 1. European solar resource map. Source: www.solargis.com

Another particular characteristic of the Iberian market is the relatively weak connection with neighbouring systems (the French and Moroccan markets), what makes it work almost like an electric island, in contrast to what happens in Central Europe, where the market is highly meshed, integrated and interconnected. This feature of the Iberian market makes the system's response to possible supply shocks more idiosyncratic.

A third characteristic that makes the Iberian case interesting is the evolution of the degree of concentration in the electric supply. The liberalisation process, together with the introduction of renewables, has led to the entrance of new players in the Iberian market, decreasing, consequently, their degree of concentration. Table 2 shows the market shares of each corporate group in the wholesale market between 2008 and 2017 and (in the last column) the value of the Herfindahl-Hirschman (HHI) concentration index, which is given by the formula: $HHI = \sum_{i=1}^{N} S_i^2$, where N is the number of participants and $S_i$is the i^{th}participant's market share expressed in a percentage. Its value ranges between 0 (infinite participants) and 10,000 (in the case of the market presenting monopoly conditions).

A wide range of authors relate the conditions of competition in a market to its levels of concentration –see for example Newbery (1995), Wolak (2000), Stoft (2002) and Helman (2006). Although there are several indicators to measure market concentration, such as the Lerner index (Landes and Posner, 1981), the Must Run Ratio (Gan and Bourcier, 2002), the Must Run Share (Wang *et al.*, 2004), the System Interchange Capacity (Goncalves and Vale, 2003), the Location Privilege (LP), and the Surplus deviation index (Bompard *et al.*, 2006), among others, the HHI (Tirole, 1988) is the most widespread among international regulators.

Table 2. Generation market shares (S_i) and HHI. 2008-2017.

Year	HHI	ENDESA	IBERDROLA	EDP	GNF	VIESGO	AXPO	ACCIONA	ENERGYA VM	WIND TO MARKET	NEXUS	DETISA	OTHERS
2008	1.484	27%	22%	13%	16%	1%	4%	3%	1%	1%	1%	1%	10%
2009	1.176	20%	23%	13%	11%	4%	7%	3%	2%	2%	1%	2%	14%
2010	1.255	19%	24%	12%	9%	3%	8%	5%	2%	2%	2%	2%	12%
2011	1.251	23%	21%	12%	7%	2%	9%	5%	3%	2%	2%	1%	12%
2012	1.236	23%	18%	16%	8%	2%	9%	5%	3%	2%	2%	1%	12%
2013	1.304	21%	19%	19%	7%	1%	8%	6%	3%	3%	2%	1%	10%
2014	1.396	21%	21%	20%	6%	1%	7%	5%	2%	3%	2%	1%	10%
2015	1.299	21%	18%	19%	7%	2%	7%	5%	2%	3%	2%	1%	13%
2016	1.279	21%	21%	14%	7%	2%	9%	6%	3%	3%	2%	1%	11%
2017	1.266	23%	18%	16%	6%	3%	8%	6%	3%	3%	2%	2%	12%

Source: CNMC (2019)

The European Commission considers that competition problems are unlikely in a market with an HHI less than 2000 and in which the largest agent has a share of less than 25% (European Parliament, 2004). Some regulatory authorities, such as for example the US Department of justice (U.S. Department of Justice, 2010) consider a market to be highly concentrated if the HHI exceeds 2500, and moderately concentrated if the HHI is between 1,500 and 2,500. Similar to Ciarreta et al. (2016), we conclude thatthe competitive conditions are reasonably assumed and our real data on hourly supply curves adequately reflect, according to OMIE, the marginal variable costs of the bidders, even in bids with complex conditions.

3. Material and methods.

The data on electricity supply and demand used in this work comes from the Iberian market operator (OMIE). This body manages the wholesale electricity market in the Iberian Peninsula (daily and intraday markets), where market agents trade the electricity amounts that they need at publicly stated and transparent prices. Its operating model is the same as the one implemented by other European markets. Participating in the market involves accessing an electronic platform (via the Internet) which permits the simultaneous participation of a large number of agents. In this platform, a high number of bids for the purchase and sale of electricity is produced over a short period of time, so the OMIE has to control the invoicing and settlement of the energy traded, including financial aspects.

In particular, the data used in this study comes from the daily market, with the offer including complex offers. The purpose of the daily market is to manage electricity transactions for the following day through the presentation of electricity sale and purchase bids by market participants. Sellers on the electric power production market are obliged to comply with the Electricity Market Activity Rules by signing the corresponding contract of adherence. Bids submitted by these sellers are presented to the market operator and will be included in a matching procedure that will affect the daily programming schedule corresponding to the day after. All the available production units that are not bound by physical bilateral contracts are required to submit bids for the daily market. Buyers in the electricity market are the relevant retailers, resellers and direct consumers. Buyers can submit bids to buy electricity on the daily market. However, to do so, they must comply with the Electricity Market Operating Rules. Once the operations in the daily market are integrated, a correspondence algorithm (called Euphemia) finds the equilibrium point (price and quantity exchanged) for each hour of the next day.

The data analysed contains, for each hour, the matched and unmatched offers and demands (demand or purchase offers) of electricity at each price level. These data allow calculating the supply and demand curves of the Iberian electricity market (Spain and Portugal) by the aggregation of the sale and purchase bids, respectively.The period under study has been between August 1, 2016 and July 31, 2017. No relevant changes were produced in the Spanish wholesale electricity market during that period, which can be considered representative of this market.

The main advantage of having data of the entire supply and demand curves (for each hour within the year) is that it allows us to calculate the market equilibrium and the surpluses of sellers and buyers directly, without the need to estimate or simulate any theoretical or empirical model based on a finite sample of observations. Since the demand curve shows the buyers' willingness to pay, the buyer's surplus is calculated as the hourly cumulative sum up to the equilibrium quantity (Q_{ti}^{Eq}) of the difference between each buyer's willingness to pay (W_{ti}^{Pay}) ad the market equilibrium price (P_t^{Eq}).

$$BuyerSurplus = \sum_{t=1}^{8760} \sum_{i=1}^{n^{\underline{o}}\ buyers} \left(W_{ti}^{Pay} - P_t^{Eq}\right) Q_{ti}^{Eq} \quad (1)$$

Likewise, the seller's surplus is calculated as the hourly cumulative sum up to the equilibrium quantity (Q_{ti}^{Eq}) of the difference between the equilibrium price (P_t^{Eq}) and the sellers' willingness to charge (W_{ti}^{Charge}, short-term marginal cost, if competitive conditions are assumed). It makes sense to consider complex offers as the marginal cost, because they include both variable and quasi-fixed factors (Filippini, 1996).

$$SellerSuperplus = \sum_{t=1}^{8760} \sum_{i=1}^{n^{\underline{o}}\ sellers} \left(P_t^{Eq} - W_{ti}^{Charge}\right) Q_{ti}^{Eq} \quad (2)$$

Finally, the total surplus (economic welfare) will be the sum of the surpluses of buyers and sellers.

The objective of the following section is to perform real comparative statics (on an hourly basis and in terms of surplus) of the Iberian electricity market between August 1, 2016, and July 31, 2017, considering the entry of new PV energy in the market. To calculate the new market situation, we need to estimate the energy produced by the 3,909 MW of PV power authorised by the Spanish government. The Photovoltaic Geographical Information System (PVGIS) tool[2] (European Commission, 2017) provides the hourly values of available PV energy per kWp according to the geographical location. This study presumes that all the PV power is installed at a central point in Spain, with irradiation levels equivalent to the average of the current PV facilities installed on the peninsula (in fact, the facilities will be spread throughout Spain, so errors should be compensated). In order to estimate the contribution of these new PV energy generators to the supply function, it is assumed that they are willing to offer at any positive price (the same situation as the currently existing PV generators), given their zero marginal cost in the short term–this assumption is also compatible with what economic theory predicts for competitive markets.

4. Empirical analysis of the Iberian electricity market.

4.1. Market equilibrium and surpluses without the quota of new PV generation.

The tables and figures of this section describe the real situation of the Iberian electricity market in the one-year period analysed. Table 3 shows the average hourly values and the accumulated yearly values of the main variables analysed. The hourly price has an average value of 50.9 €/MWh, with a standard deviation of 12.0 €/MWh and a maximum price of 102 €/MWh. On the other hand, almost 30,000 MWh are exchanged every hour on average, with a standard deviation close to 5,000 MWh.

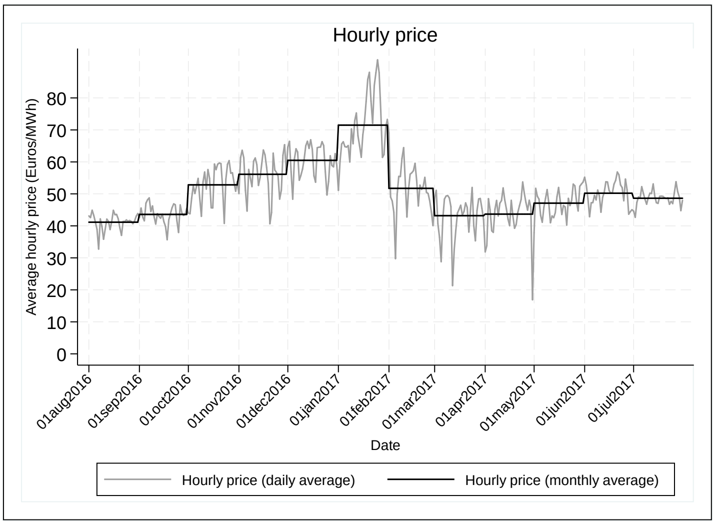
2 On the tool PVGIS, see http://re.jrc.ec.europa.eu/pvgis.

The complete visualisation of the marketallows us to calculate the surpluses obtained every hour by buyers and sellers, respectively. Thus, on average, the sum of both surpluses (i.e., the total surplus) is of about 4 million Euros per hour, of which nearly 3 million € correspond to the buyers. The average surplus of sellers is close to 1 million €/hour on average, although it reached a maximum value of 2.8 M€ on January 19 at 9:00 p.m. In a full year (8760 hours), buyers have accumulated a surplus that is close to 26 billion euros (72% of the total accumulated surplus), while sellers have amassed a surplus of almost 10 billion euros (28%). This percentage distribution is compatible with the consumers' perception of the great value of electricity, and the high opportunity cost of being without it –in fact, the buyer surplus could be much higher if we did not take into account that the maximum purchase price in the Spanish daily market is set at 180 € per MWh.

Table 3. Description of the variables before the entry of new Energy.

Variables	Mean	Std. Dev.	Min	Max
Hourly price (€/MWh)	50.9	12.0	2.3	102.0
Hourly electricity (MWh)	27,544	5,090	14,507	41,156
Buyer hourly surplus (€)	2,949,195	500,996	1,496,656	4,402,908
Seller hourly surplus (€)	1,130,886	372,415	43,782	2,830,462
Total hourly surplus (€)	4,080,081	777,141	1,925,600	6,030,127
Buyer annual surplus (€)	25,831,999,488			
Seller annual surplus (€)	9,905,426,432			
Total annual surplus (€)	35,737,427,968			

The two graphs of Figure 2 show, respectively, the evolution of the equilibrium price and quantity in the daily market. Specifically, the daily average of the hourly price (the first graph) and the daily cumulative value of the hourly energy (the second graph) are represented. These values are also accompanied by their respective monthly averages in order to smooth out their high intraweek volatility. In both series, price and quantity, a clear seasonal component is observed: June and July, on the one hand, and from November to February, on the other, are the months with the highest prices and quantities. Obviously, behind this seasonalevolution, there are movements of supply and/or demand that can be captured with our exhaustive database.



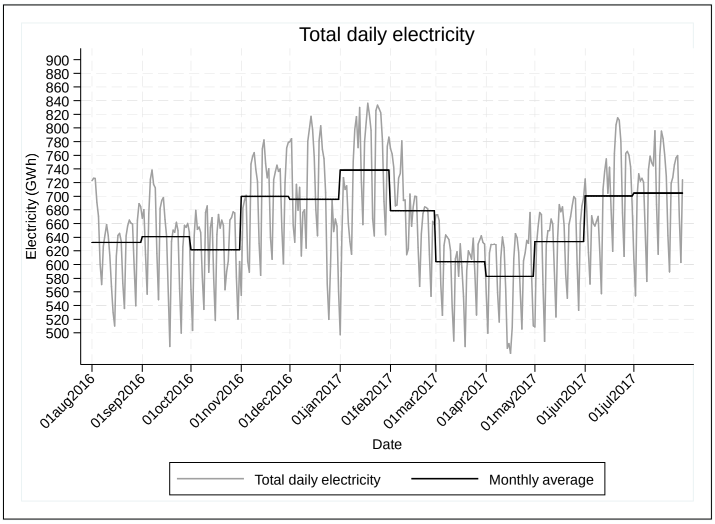
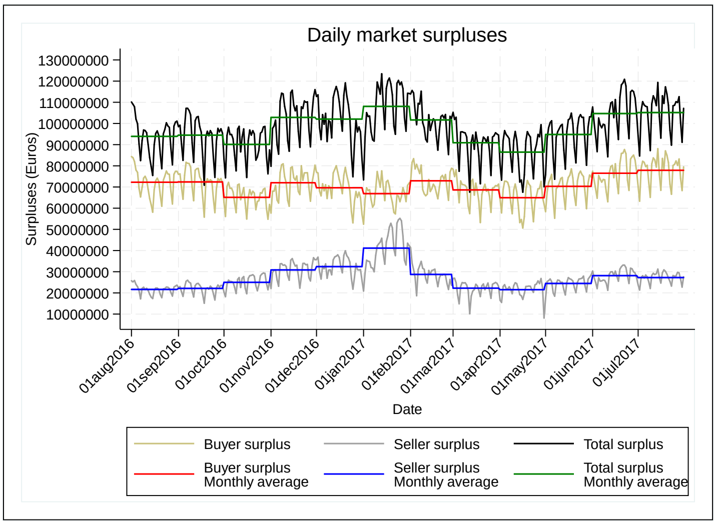


Figure 2. Evolution of equilibrium price and quantity in the daily market. August 1, 2016, to July 31, 2017.

The two plots of Figure 3 depict the evolution of the daily market surpluses in levels and percentages respectively –the daily values are the result of accumulating the hourly surpluses generated throughout the day. The seller surplus follows an evolution quite similar to that of the market price, it is relatively high at the beginning of summer and in winter. The evolution of the buyer surplus is flatter than that of the sellers and has a less clear pattern. In percentage terms (the second graph), the buyer surplus oscillates around 70%, while that of the sellers does so around 30%. This percentage gap narrows significantly in the month of January, where the distribution is closed from 60% to 40%.



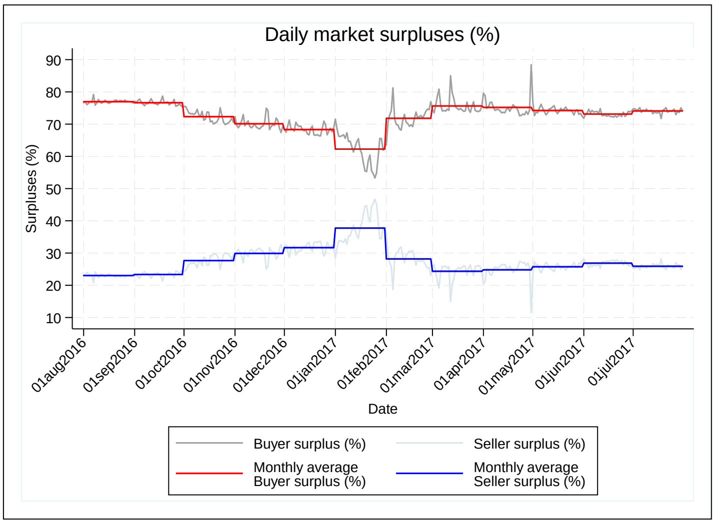


Figure 3. Evolution of the market surpluses in the daily market. August 1, 2016, to July 31, 2017.

4.2. Market equilibrium and surpluses with the quota of new PV generation.

As was mentioned in Section 2, during the year 2017, the Spanish Government authorised the construction of 3,909 MW of new PV power under advantageous conditions for the developers. In addition to providing the connection point, the Spanish Government assured a minimum price for its energy production, with the corresponding mitigation of the financial risk. The objective of this regulatory measure was to reduce Spanish CO_2 emissions, which contributes to achieving the commitments assumed in the Paris Agreement.

A new market equilibrium arises once the energy generated by these new PV facilities is incorporated into the hourly supply curve, while the hourly demand function remains the same –as we will see next, the inelastic nature of the electricity demand curve is an important factor in our comparative statics. It makes sense to analyse this supply shock in the short term, since the construction and connection time of these plants must be relatively short due to the technology's relative simplicity. Moreover, the fact that the promoters have to financially endorse their plants in order to access the business ensures, to a certain extent, the start-up of the facilities.

As described in Section 2, for the estimation of the variation in the energy supply, it is assumed that all new PV facilities are located at a geographical point with an average irradiation (this average value is the one of the current facilities in operation). Under this assumption, the PV-GIS tool allows us to calculate the hourly PV production. Once the energy produced each hour with the new PV power is known, it is assumed that this energy is offered to the market at its marginal cost, which is close to zero, as it is the one of the PV facilities that are currently in operation. In this way, the supply curve experiences a parallel shift to the right in the hours of sunshine.

The following tables and figures analyse the variation that occurs in the main market variables when the new PV energy is supplied. Table 4 shows that the hourly electricity is on average 2.7 €/MWh cheaper with the new supply curve –this effect on the price is also in line with that achieved by Gelabert et al. (2011) for the Spanish case–, while the hourly consumption increases by 359.7 MWh.These values correspond to the hours of sun; if the average values were calculated taking into account all the hours of the year, they would be 1.5 €/MWh and 198.5 MWh respectively. As for the market surpluses, that of the sellers falls about 18,000 € per hour on average, while that of the buyers increases by about 81,000 € per hour (both figures refer to sun hours). These hourly results, accumulated during all the hours of the year, give rise to a loss of seller surplus of 83.4 million € and a gain of consumer surplus of 380.5 million €. As a result of this, the total surplus increases about 297 million euros in a year. As predicted by economic theory, when analysing the effects of new technology, it is important to keep in mind that what is bad for firms is not necessarily bad for society as a whole. Improvement in generation technology can be bad for marginal sellers who become increasingly unnecessary, but it is surely good for consumers who pay less for electricity.

Table 4. Description of the variation of the variables after the entry of new PV energy.

Variable	Mean	Std. Dev.	Min	Max
New PV electricity (MWh)	1285.6	832.6	10.9	2699.1
Hourly price differential (€/MWh) (total hours of the year)	-1.5	2.2	-17.1	0.0
Hourly price differential (€/MWh) (sunlight hours of the year)	-2.7	2.4	-17.1	0.0
Annual quantity differential (MWh)	1,685,977			
Buyer annual surplus differential (€)	380,538,880			
Seller annual surplus differential (€)	-83,389,440			
Total annual surplus differential (€)	297,148,416			

If we divide the total new PV energy offered in the year, which is 6,025,700 MWh (2.5% of the annual exchanged quantity), between the 4,687 hours of PV generation (53.5 % of the total hours of the year), an average hourly energy of 1,285.6 MWh (every sun hour) is obtained. Then, our datasuggest that one additional MWh of new PV electricity reduces the hourly price by 0.0021 €/MWh –this result comes out of dividing the hourly price reduction (2.7 €/MWh) by the additional energy in every hour of sunshine (1,285.6 MWh). From these data, we can do the following linear extrapolation: if an additional capacity of 3,909 MW can generate 1,285.6 MWh of additional energy every hour of sunshine, 15 MW of PV power would generate approximately 5 MWh of electricity each hour of sunshine, contributing to reducing the hourly price (in sunny hours) by 1 € cent (–0.01 € = 5 MWh x –0.0021 €/MWh), and to increasing the annual total surplus by 1.14 M€ approximately. If this reasoning is applied to all the hours of the year (not only to sunshine hours), it is obtained that to achieve a reduction of 1 € cent in the hourly price, it would be necessary to install about 25 MW of new PV plants. These results can be presented as a rule of thumb, that is: *The average price of energy will decrease by 1 c€ for every 25 MW of new PV generation installed. This decrease will be greater (in absolute values) in the hours of more irradiation, being zero at night (see Table 4) and presenting an average value of 1.7 c€ in the hours of sunshine. In the hours of maximum irradiation, the reduction of prices would be higher than 10 c€.*

In the light of the previous results, the impact of the commissioning of the 3,909 MW authorised by the Spanish government will represent a reduction of around 8% in the revenue of the current PV producers (incumbents), a reduction that should be taken into account by these companies when they make their financial projections, development plans or mergers and acquisition movements. To estimate this reduction, the revenue that a 10 MW PV plant would get before and after the commissioning of the authorised PV power has been simulated for each hour of the year, obtaining that its revenue would be reduced from 790,133 to 730.456 €.

Figure 4 depicts the evolution of the price and quantity differentials once we consider the generation of new PV energy. The negative variation of the (24 hours) average daily price (the first graph) and the positive variation of the (24 hours) average daily quantity (the second graph) are greater in the spring and summer seasons, periods when the solar production is more important and/or the electricity demand moderates.

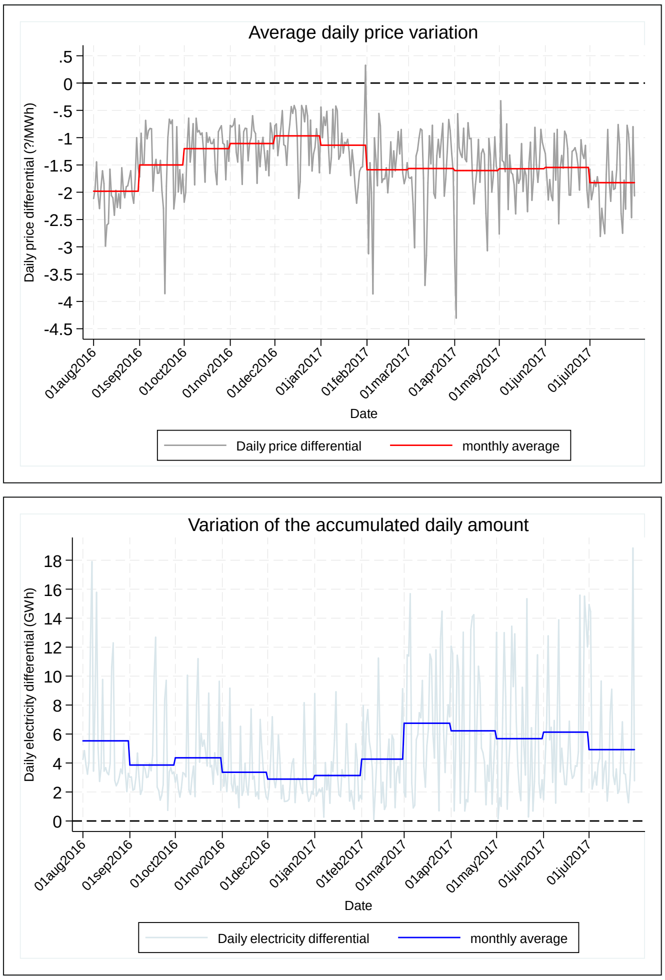


Figure 4. Evolution of price and quantity variations. August 1, 2016, to July 31, 2017.

As for the surpluses, Figure 5 shows the evolution of the respective daily surplus variations, all of them expressed in levels ad in percentages. The first graph shows that the variation of the daily buyer surplus is around 1 million €, although it reaches a maximum value close to 3 million € on June 30, 2017. On the other hand, the variation in the seller surplus is negative and oscillates around –0.5 million €; the maximum fall of this surplus reaches –2.5 million euros the same day as before (June 30, 2017). On the whole, the daily total surplus experiences a positive variation that moves below, but close to, 1 million € throughout the period. In relative terms (the second graph), the entry of new PV energy causes a weight gain of the buyer surplus in the total surplus (with the corresponding weight loss of seller surplus) which oscillates around 1 percentage points over the year, although on specific days this gain may exceed three percentage points.

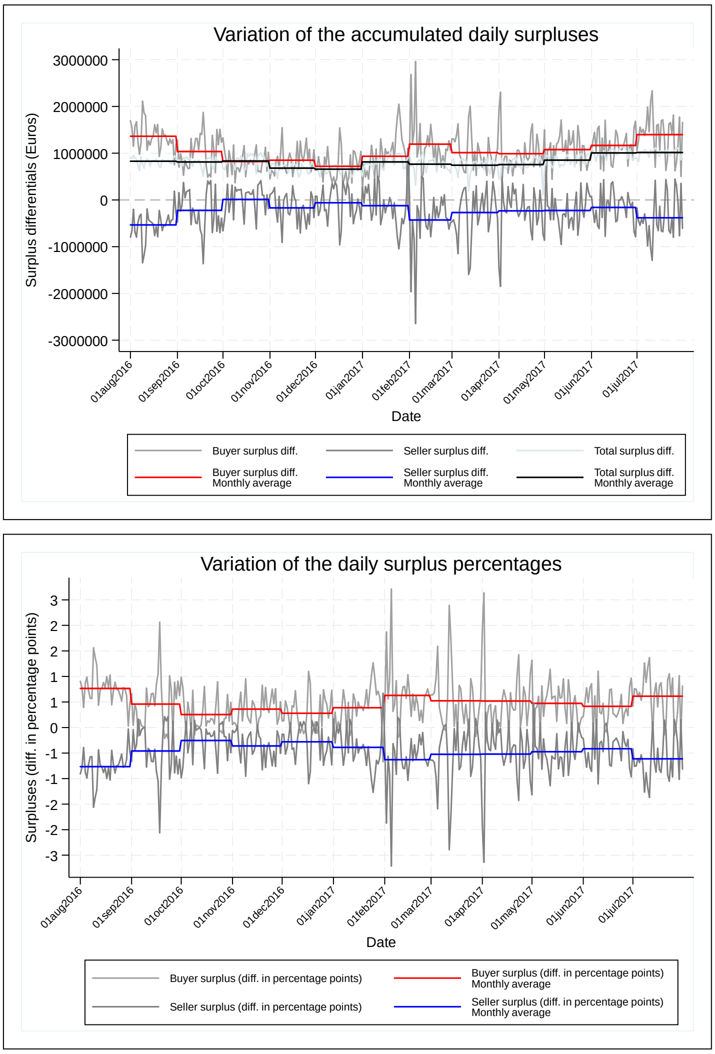


Figure 5. Evolution of surplus variations. August 1, 2016, to July 31, 2017.

Our analysis continues with the study of market dynamics. For this purpose, we propose the estimation of a linear mixed model of the hourly price in the Spanish wholesale electrical market. Linear mixed or multilevel models are models containing both fixed effects and random effects. They are a generalization of linear regression allowing for the inclusion of random deviations other than those associated with the overall error term of the model –on multilevel analysis, see for example Cameron and Trivedi (2005) and Goldstein (2011). They have been used in a wide range of domains, such as education, medicine, labour market, etc., but their presence in studies on the behaviour of the electricity markets is scarce at present. There are some studies that use this technique to predict either load profiles or electricity prices. For example, Koen et al. (2014) presents an approach that uses multilevel models to develop scenario forecasts for South African load profiles, which can then be used to support decisions regarding the electricity generation capacity required – their data show a high degree of correlation among intra-day hours. Tso and Guan (2014) estimate a multilevel regression model to calculate the magnitude and significance of effects of environment indicators and household features on residential energy consumption un the US. According to these authors, the benefit of this approach is that, based on stratified sampling schemes, allows to extract cluster effects from total variations of the dependent variable. García-Martos et al. (2007) state that they estimate a mixed model for short-run forecasting of prices in the Spanish Electrical Market but, in our opinion, the term ‘mixed’ is confusing in this article because, rather than estimating a multilevel model, these authors simply propose to model 24 hourly time series separately, instead of modelling a complete time series of the prices. As far as we know, there are no previous studies that make use of in-sample predictions, in a multilevel residuals scheme, to compare markets with different scenarios of renewable electricity supply.

After trying several specifications, we propose an autoregressive AR(2) two-level model of the hourly market price which is going to be estimated in the two scenarios generated in this article: with and without the new PV power. In the mixed model, the first level corresponds to the hourly observations and the second level to the 365 days of the year. When hourly observations are nested in their respective days, we are admitting that hours of the same day tend to be more alike than hours chosen at random from the population. Different reasons may explain the specificity of each day of the year: festive days, weather conditions, political issues, religious celebrations, sporting events, power grid problems, etc.; our model allows to control this kind of unobservable heterogeneity.

As can be seen in the following equations, the model proposed assume that *purely random effects* affect the intercept of the model and the slopes of the dummy variables on the day of the week –the likelihood-ratio χ^2 test of null hypothesis of *no different in fit between nested models* favours this specification against other nested alternatives–:

Level 1 model:

$$P_{h|d} = \beta_{0,d} + (\beta_{1,2} \dots \beta_{1,12})\begin{pmatrix} D_{\text{February}} \\ \dots \\ D_{\text{December}} \end{pmatrix} + (\beta_{2,1,d} \dots \beta_{2,6,d})\begin{pmatrix} D_{\text{Monday}} \\ \dots \\ D_{\text{Saturday}} \end{pmatrix} + (\beta_{3,2} \dots \beta_{3,24})\begin{pmatrix} D_{\text{hour 2}} \\ \dots \\ D_{\text{hour 24}} \end{pmatrix} + \varepsilon_{h|d} \tag{3}$$

$$\text{with } \varepsilon_{h|d} = \emptyset_1 \varepsilon_{h-1|d} + \emptyset_2 \varepsilon_{h-2|d} + u_{h|d} \quad \text{where} \quad u_{h|d} \text{ iid} \sim N(0, \sigma_u^2)$$

Level 2 model (specific day in the year, 365 days or groups of 24 hours):

$$\beta_{0,d} = \gamma_{00} + v_{0,d} \quad \text{where } v_{0,d} \text{ iid} \sim N(0, \sigma_v^2), \text{cov}(v_{0,d}, u_{h|d}) = 0 \tag{4}$$

$$\beta_{2,j,d} = \gamma_{2,j} + w_{2,j,d} \text{ where } w_{2,j,d} \text{ iid} \sim N(0, \sigma_{w_{2,j}}^2), \text{cov}(w_{2,j,d}, u_{h|d}) = 0, \text{cov}(w_{2,j,d}, v_{0,d}) = 0 \text{ for } j = 1, \dots, 6$$

Integrating both models:

$$P_{h|d} = \gamma_{00} + (\beta_{1,2} \dots \beta_{1,12})\begin{pmatrix} D_{February} \\ \dots \\ D_{December} \end{pmatrix} + (\gamma_{2,1} \dots \gamma_{2,6})\begin{pmatrix} D_{Monday} \\ \dots \\ D_{Saturday} \end{pmatrix} + (\beta_{3,2} \dots \beta_{3,24})\begin{pmatrix} D_{hour\ 2} \\ \dots \\ D_{hour\ 24} \end{pmatrix} + + v_{0,d} + (w_{2,0,d} \dots w_{2,6,d})\begin{pmatrix} D_{Monday} \\ \dots \\ D_{Saturday} \end{pmatrix} + \emptyset_1 \varepsilon_{h-1|d} + \emptyset_2 \varepsilon_{h-2|d} + u_{h|d} \tag{5}$$

The response variable is the hourly electricity price $P_{h|d}$. The fixed part of the model is composed of the global average price for all the hours (γ_{00}) plus the dummy variables which control for the month of the year $\{D_{February}, \dots, D_{December}\}$, the day of the week $\{D_{Monday}, \dots, D_{Saturday}\}$ and the hour of the day $\{D_{hour\ 2}, \dots, D_{hour\ 24}\}$ –dummies $D_{January}$, D_{Sunday} and $D_{hour\ 1}$ are omitted from the estimate in order to avoid multicollinearity. The random portion of the mixed model is composed of two parts. On the one hand, the coefficients ($v_{0,d}$; $w_{2,0,d} \dots w_{2,6,d}$) measure the specificity (random intercept) of every particular day of the year $(v_{0,d})$ and the cross-effects $(w_{2,0,d} \dots w_{2,6,d})$ that every particular day of the year has on the slopes of the weekday dummy variables –effectively, our data confirm that the effect of the weekday on the hourly electricity price depends on the particular day of the year in which we are. Note also that the coefficients of weekday variables $(\beta_{2,j,d} = \gamma_{2,j} + w_{2,j,d} j = 1, \dots, 6)$ have been estimated as random slopes in the model, but given their character of dummy variables (0 or 1), they end up conditioning the intercept of the model. On the other hand, the overall or level 1 error term ($\varepsilon_{h|d}$) is supposed to follow an autoregressive structure of order 2 in order to control for the temporal correlation between successive level 1 residuals; this means that two more coefficients are estimated in the model ($\emptyset_1$ and $\emptyset_2$). In summary, in our mixed model the average hourly price of a specific day within the year can move away from the global average of the year and, in addition, the intraday prices can move away, only temporarily, from their specific average.

The 2-level model has to be estimated by using maximum likelihood techniques (or by Bayes methods) since it has got a composite error term whose variance is partitioned into the between-day variance component (the variance of the level 2 residuals) and the between-hour variance component (the variance of the level 1 residuals). Table 5 shows the results of estimating the mixed model using as dependent variable the market equilibrium price without (model 1) or with (model 2) the new PV power allowed by the Spanish Government. In order to measure the pure effect of the new PV power, both estimates use only the sun hours (where there is PV generation).

Table 5.
Multilevel model for hourly electricity price in Spain. Estimation results.

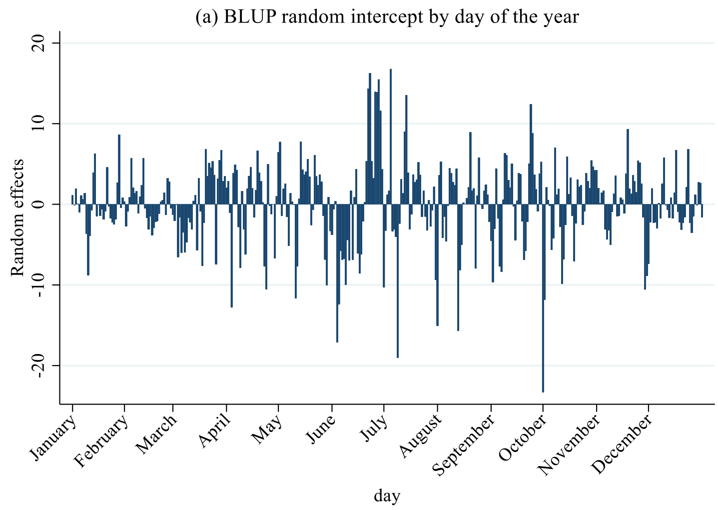
		MODEL (1) WITHOUT NEW PV POWER				MODEL (2) WITH NEW PV POWER			
		Mixed-effects ML regression		Number of obs. = 4686		Mixed-effects ML regression		Number of obs. = 4686	
		Group variable: día		Number of groups = 365		Group variable: Day		Number of groups = 365	
				Wald chi2(31) = 2708.95				Wald chi2(31) = 2657.18	
		Log likelihood = -9829.6638		Prob > chi2 = 0.000		Log likelihood = -10282.995		Prob > chi2 = 0.000	
		Coef.	Std. Err.	z	P>z	Coef.	Std. Err.	z	P>z
Reference month: January	February	-20.77	1.41	-14.77	0.00	-21.28	1.45	-14.63	0.00
	March	-30.07	1.36	-22.09	0.00	-31.00	1.41	-22.03	0.00
	April	-30.33	1.37	-22.16	0.00	-31.22	1.41	-22.07	0.00
	May	-27.72	1.36	-20.42	0.00	-28.71	1.40	-20.46	0.00
	June	-23.89	1.37	-17.44	0.00	-24.88	1.42	-17.58	0.00
	July	-25.2	1.36	-18.56	0.00	-26.50	1.40	-18.89	0.00
	August	-33.09	1.36	-24.33	0.00	-34.49	1.41	-24.53	0.00
	September	-30.33	1.37	-22.06	0.00	-31.03	1.42	-21.83	0.00
	October	-19.68	1.37	-14.37	0.00	-19.86	1.42	-14.02	0.00
	November	-15.81	1.38	-11.44	0.00	-15.77	1.43	-11.03	0.00
	December	-11.8	1.38	-8.54	0.00	-11.37	1.43	-7.94	0.00
Reference weekday: Sunday	Monday	11.25	1.04	10.79	0.00	11.77	1.08	10.93	0.00
	Tuesday	12.27	1.05	11.71	0.00	12.90	1.08	11.91	0.00
	Wednesday	12.8	1.05	12.22	0.00	13.45	1.08	12.42	0.00
	Thursday	12.71	1.05	12.13	0.00	13.32	1.08	12.30	0.00
	Friday	12.37	1.05	11.8	0.00	12.97	1.08	11.97	0.00
	Saturday	6.11	1.05	5.84	0.00	5.93	1.08	5.48	0.00
Reference hour of day: 6:00 am	Hour 7	2.22	0.15	14.7	0.00	1.83	0.17	11.03	0.00
	Hour 8	4.95	0.22	22.14	0.00	3.93	0.24	16.30	0.00
	Hour 9	7	0.26	26.78	0.00	5.06	0.28	18.12	0.00
	Hour 10	8.26	0.29	28.8	0.00	5.21	0.30	17.11	0.00
	Hour 11	8.32	0.3	27.39	0.00	4.28	0.32	13.28	0.00
	Hour 12	7.61	0.31	24.17	0.00	2.75	0.33	8.23	0.00
	Hour 13	7.26	0.32	22.58	0.00	2.03	0.34	5.93	0.00
	Hour 14	7.03	0.33	21.62	0.00	1.75	0.35	5.03	0
	Hour 15	5.81	0.33	17.78	0.00	0.84	0.35	2.41	0.02
	Hour 16	4.26	0.33	13	0.00	0.17	0.35	0.49	0.63
	Hour 17	3.81	0.33	11.62	0.00	0.92	0.35	2.6	0.01
	Hour 18	5.08	0.33	15.46	0.00	3.75	0.35	10.58	0
	Hour 19	6	0.34	17.89	0.00	5.62	0.36	15.47	0
	Hour 20	7.43	0.36	20.94	0.00	7.6	0.39	19.73	0
	Constant	59.01	1.2	49.01	0.00	59.62	1.25	47.79	0
	Random-effects Parameters	Estimate	Std. Err.	[95% Conf. Interval]		Estimate	Std. Err.	[95% Conf. Interval]	
	day: Identity								
	var(R.Weekday)	23.03	2.21	19.09	27.79	23.54	2.45	19.2	28.87
	Residual: AR(2)								
	Φ_1	1.24	0.02	1.21	1.27	1.19	0.02	1.16	1.22
	Φ_2	-0.41	0.02	-0.45	-0.38	-0.36	0.02	-0.4	-0.33
	var(ε)	15.21	1.07	13.26	17.45	17.87	1.37	15.37	20.78
	LR test vs. linear model	chi2(3) = 10248.62; Prob > chi2 = 0.0000				chi2(3) = 9892.35; Prob > chi2 = 0.0000			

Examining the estimation results of the fixed portion of models (1) and (2), we observe that the dummy variables for month, day of the week and hour of the day are significant at the 95% confidence level. Moreover, the coefficients of the dummy variables that control for the month and the day of the week are similar in both models, the same not happening with the coefficients of the hours of the day, whose difference increases between 12:00 pm and 14:00 pm; that is, the price of electricity is more than 4 € cheaper in those hours in model (2), logically due to the greater weight of solar production in this second scenario (note that the intercepts of both models are quite similar, just over 52 € per MWh).

The dummies for months show a relevant price increment in winter –for example, January is more than 30 €/MWh more expensive than August or September in both models. The coefficients for weekday dummies illustrate that Sunday is the cheapest day and Wednesday and Thursday the most expensive (these two days are about 13 € more expensive than Sunday in both models). Finally, the most expensive sun hours are those that go from 10:00h to 12:00h –for example, in model (1), electricity at 11:00 am is 8.32 €/MWh more expensive than at 6:00 am; this figure drops to 4.28 €/MWh in model (2). These results do not have to match with those observed in other countries, for example, Ketterer (2014) finds that the electricity price in Germany remains high at the beginning of the week (falling from Friday onward), and observes that, in October and November, the price is significantly higher than in January, which is not our case.

The random part of the model allows us to estimate the two variance components, the between-day variance component (variance of level 2 residuals) and the between-hour variance component (variance of level 1 residuals). The variance of the level 2 residuals is somewhat greater than 23 in both models, or said otherwise, the standard deviation of the random effect of the specific day of the year is approximately 5 €/MWh. As for the level 1 AR(2) residuals, we observe that the sum of the two autoregressive coefficients ($\emptyset_1$ and $\emptyset_2$) is less than the unit in both models (0.83 in both cases), so the hourly electricity price follows an stationary process –on autoregressive models see, for example, Hamilton (1994), Lütkepohl (2005), and Stock and Watson (2001). Moreover, the variance of the white-noise disturbance (σ_u^2) is 15.21 in model (1) and 17.87 in model (2). Therefore, compared to model (1), model (2) results in a lower mean price prediction but a greater price variance; this higher volatility is possibly due to the fact that the PV energy, which is greater in model (2), is intermittent (power generation from solar panels cannot be scheduled in advance and depends on the level of irradiation in each hour).

Mixed-modelling research often focus on the fixed effects, with random effects included only to control for unobserved heterogeneity in the data. However, random effects can themselves be values of interest. Mixed models offer the possibility to estimate the best linear unbiased predictions (BLUP) of random effects. Figure 6 allows analysing these effects. The graph (a) of the figure depicts the random intercepts in model (1) for each specific day of the year (random intercepts of model (2) are quite similar), while the graph (b) shows the standard deviation of level 2 residuals for each day of the week in both models –keep in mind that, for each day of the week $\{Sunday, \ldots.., Saturday\}$, we have 52 BLUP random effects that depend on the specific day of the year. As can be seen in graph (a), there exists unobservable heterogeneity associated to the specific day of the year, and this heterogeneity causes increases or decreases in the price that can exceed 20 €/MWh. For its part, graph (b) shows that the greatest price dispersion due to the effect of the specific day of the year occurs on Sundays; ergo, considering only the 52 Sundays of the year, the level 2 random effects have a standard deviation of about 6 €/MWh in both models –this standard deviation is approximately 4 €/MWh the rest of the days. This fact makes sense due to the less industrial nature of Sunday's electricity demand. On Sundays, electricity demand is lower and comes mainly from households (its fixed industrial component is smaller), so the market price is more influenced by temperature and weather conditions than other days of the week.



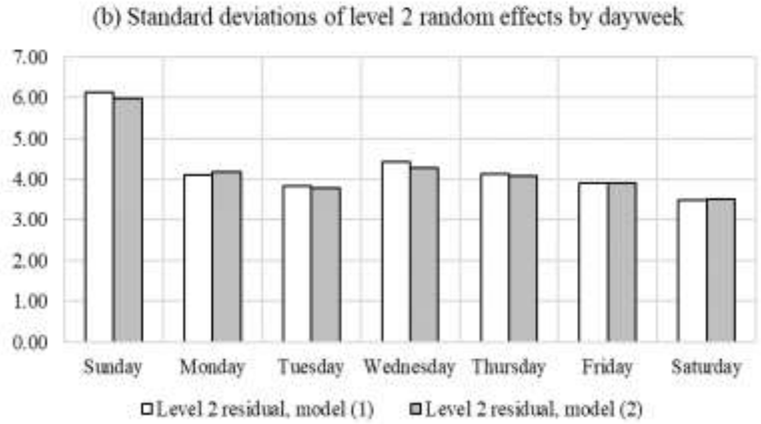


Figure 6. BLUP of Level 2 random intercepts.

4.3. CO_2 emissions.

In the previous sub-section, the effect on the daily market of introducing the PV power assigned in the 2017 auctions has been analysed. The entrance of more PV capacity in the supply curve involves the incorporation of clean (zero emission) energy and the expulsion of marginal technology from the market. The TSO, *Red Eléctrica de España* (REE), provides information on the technologies that, each hour, participate in the market according to their order of merit. The incorporation of emission-free energy from the new PV plants will lead to an expulsion of the marginal technology, which in all the cases in our data (sunshine hours) corresponds to the combined cycle technologies –if the incorporation of PV power had been greater, it could have also displaced the coal plant technology, but this is not the case in our data.

According to the Spanish System Operator (REE), the CO_2 emission rate of the combined cycle technology is 370 gCO_2/kWh (Arcos-Vargas et al., 2018). The solar energy incorporated into the market does not generate emissions, and the energy displaced (coming from the combined cycle) allows avoiding 0.37 Mt. CO_2 per MWh. As we have seen in the previous sections, the incorporation of the 3,909 MW of PV generation will generate a little more than 6 TWh of additional energy, so that the CO_2 savings can be estimated as follows:

$$\mathrm{CO_2\ Emission\ Reduction} = 0.37\ \frac{\mathrm{Mt.\ CO_2}}{\mathrm{MWh}} \cdot 6\ \mathrm{TWh}\ \cdot \frac{1{,}000{,}000\ \mathrm{MWh}}{1\ \mathrm{TWh}} = 2{,}220{,}000\mathrm{Mt\ CO_2} \qquad (4)$$

This figure would be the contribution that this PV generation initiative would have to reach the national commitments that Spain adopted in the Paris Agreement (Arcos-Vargas, 2016). In order to make an economic valuation, one has to consider the long-term CO_2 price, which S&P Global Platts figures at 35-40 €/Mt (Watson, 2018). With this price, the additional benefits obtained from the incorporation of PV generation would amount to 80 Million€ per year approximately.

5. Conclusions and policy implications.

This paper quantifies the impact that the commissioning of the new PV facilities (3,909 MW of PV power) approved by the Spanish Governmentin 2017 will have on the Spanish electricity market. The effects are measured in terms of market price, quantity exchanged, CO_2 emissions, and economic surpluses across the market. As the complete supply and demand curves of hourly electricity in the day-ahead market are known, the study looks directly at the electricity market, instead of estimating or simulating behavioural models from a given data sample. The complete characterisation of the Iberian daily market is possible thanks to the data on purchase and sale bids published by the Iberian Operator Market (OMIE).

According to our data, the economic welfare (total surplus) transmitted to society by the daily electricity market between August 1, 2016 and July 31, 2017 is very large (35.7 billion €). Most of this welfare (72%) corresponds to the buyer's side, which is consistent with the high value that users give to electricity. In temporary terms, the month in which the greatest welfare is generated is January, which coincides with the period of higher prices and hourly quantities exchanged. In this month, the buyer surplus' share decreases by up to 60%.

The entry into service of the PV power allocated in the 2017 auction will enable the supply to generate an additional clean energy of 6 TWh in a year, which represents 2.5% of peninsular energy demand. This positive supply shock has been analysed by using comparative statics and by estimating an *ARIMAX* model for the hourly electricity price. Three main results are extracted from the analysis. On the one hand, a positive supply shock consisting of the introduction of 1 MWh of PV electricity will reduce the electricity price by 0.002 €/MWh on an hourly average (in the hours of sun). Likewise, 25 MW of new PV power would be needed to reduce the average hourly price by 1 € cent. Thisprice reduction will be greater (in absolute values) in the hours of more irradiation, being zero at night and presenting an average value of 1.7 c€ in the hours of sunshine.

The potential impact of the commissioning of the 3,909 MW authorised by the Spanish government will represent a reduction of around 8% in the revenue of the current PV producers (incumbents), which must be taken into account when making their financial projections, development plans or mergers and acquisitionmovements.

Regarding environmental issues, the CO_2 savings for replacing contaminating technologies with non-contaminating ones will amount to 2.2 million Mt; this saving will contribute to the Spanish Government's compliance with the commitments adopted in the Paris Agreement. On the other hand, in terms of economic welfare, the greater electricity supply will cause an increase in total surplus of 300 M€ in a year, although its distribution will be asymmetrical. While the buyer surplus will increase by almost 400 M€, the seller surplus will decrease by about 100 M€.

Our analysis shows that a new situation arises in the market when additional PV energy is introduced into the equation. This supply shock positively affects the system as a whole but causes the expulsion of less efficient firms (mainly combined cycle units) and the reduction of the joint contribution margin of the companies that remain in the market. To redirect this situation to a Pareto optimum, a monetary compensation could be given to those companies with less efficient technologies which would leave the market if they could not maintain their contribution margins and financial results. In return, these companies should offer support to the auxiliary services of the market and to the security of the network, which simultaneously improves the system’s reliability and security, increasing the buyers’ surplus, without reducing the sellers’ initial surplus.

For future research, the effect on the electricity market of other supply shocks (the closure of coal-fired power stations, nuclear power stations, higher levels of penetration of renewables, etc.) and demand shocks (the electrification of transport, heating, industrial applications, etc.) could be analysed. The richness of OMIE’s databases allows addressing these types of analysis.

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