Effects of self-generation in imperfectly competitive electricity markets: The case of Spain

David Ribó -Pérez[a,*], Adriaan H. Van der Weijde[b], Carlos Álvarez Bel[a]

[a] Institute of Energy Engineering, Universitat Politècnica de València Camí de Vera S/N, 46022 Valencia, Spain

[b] School of Engineering, The University of Edinburgh, Scotland, UK, & The Alan Turing Institute, London, UK.

Abstract—Domestic rooftop photovoltaic (PV) energy can reduce net electricity demand, and therefore reduce energy prices through a merit-order effect. This reduces profits of all incumbents in the electricity markets. In addition, in imperfectly competitive markets, PV self-generation reduces prices through a reduction in market power. The first effect may warrant additional policy interventions to maintain cost recovery, but the second is much more desirable, as it simultaneously helps increase sustainability and competition. However, unlike a simple reduction in market prices, the competition effect affects all incumbents differently. Since resistance from incumbents can be a significant barrier to energy policy change, it is important to understand the distribution of effects. This paper does so for the Spanish market. A Nash-Cournot model and a simplified representation of the Spanish electricity market is used to determine the merit-order and competition effects of an increase in solar self-generation. We conclude that both are important, and that their analysis is essential to inform the social debate around PV policy.

Keywords—PV; self-generation; wholesale electricity market; imperfect competition; modelling.

Nomenclature

The mathematical symbols used throughout this paper are classified below as.

Indexes

i	nodes
f	firms
h	generation technologies
k	lines
t	time periods

Parameters

MD_{it}	Maximum demand of electricity at node *i* during time period *t*
$MaxP_{it}$	Maximum price at node *i* during time period *t*
ε_{it}	Elasticity at node *i* during time period *t*
Q_t	Total electricity consumption during time period *t*
q_{it}	Quantity of electricity consumed at node *i* during time period *t*
RV_{ih}	Regional variation at node *i* of generation technology *i*
CF_{ih}	Capacity factor at node *i* of generation technology *h*
$\overline{CF}_h$	Mean capacity factor of generation technology *h*
$PTDF_{ik}$	Power Transfer Distribution Factor of line *k*, node *i*
$\overline{X}_{fiht}$	Maximum generation capacity oftechnology *h* from firm *f* at node *i*
$\underline{X}_{fiht}$	Minimum generation capacity of technology *h* from firm *f* at node *i*
$MaxP_{it}$	Maximum price at node *i* during time period *t*
SG_{it}	Solar PV self-generation at node *i* during time period *t*
MF_k	Capacity of line *k*

Variables

s_{fit}	Sales of firm *f* at node *i* during the time period *t*
x_{fiht}	Generation of firm *f* at node *i* with technology *h* during time period *t*
B_f	Profits of firm *f*
W_{it}	Transmission cost at node *i* during time period *t*
ρ_{fiht}	Dual variable of the maximum generation bound of technology *h* from firm *f* at node *i*. time period *t*
β_{fiht}	Dual variable of the minimum generation bound of technology *h* from firm *f* at node *I*, time period *t*
θ_{ft}	Dual variable of the within-firm energy balance constraint, for firm *f* at time period *t*
λ_{kt}^{+}	Dual variable of the upper thermal limit of line *k* at time period *t*
λ_{kt}^{-}	Dual variable of the lower thermal limit of line *k* at time period *t*

1. Introduction

Scientific evidence overwhelmingly shows that climate change threatens our habitat and is a global risk that needs to be addressed universally and urgently (Stern, 2007; IPCC, 2014). This issue has generated much discussion about the necessity for reducing emissions and how this can be accomplished. One of the main *foci* of greenhouse gas (GHG) emissions reduction has been electricity generation, as this has traditionally been based on fossil fuel burning. Renewable energy sources (RES) are offering an alternative that is currently paving a way to decarbonise the sector.

Solar photovoltaic energy is becoming an economically feasible technology for reducing emissions by generating energy, not just in centralised facilities, but also in a way known as solar self-generation (SG). With SG systems, electricity consumed in buildings is generated locally by the installation of PV panels, normally deployed on rooftops. This new way of generating has become feasible after large reductions in Photovoltaic (PV) costs of around 6-7% per year since 1998 (Barbose *et al.*, 2013; Fu *et al.*, 2017). Nowadays, PV is reaching economic competitiveness and represents a viable alternative to other generating sources in many parts of the world. This is a massive opportunity, since approximately 20% of all GHG emissions result from energy consumed in buildings (IPCC, 2014). Besides GHG emission reduction, self-generation has a number of other advantages: electricity is produced where it is consumed, so reliance on transmission infrastructure is reduced; private investors face the cost of deploying new generating capacity instead of the governments; and reductions on countries' energy dependence.

However, this concept embodies a significant legal and economical shift in a sector where previously only a few players existed. In the past, a small number of firms owned large generating facilities (taking advantage of economies of scale) from where they produced electricity that was then distributed to the loads. This contrasts with the multitude of homeowners, offices, small business and industry who now have the capability to generate their own electricity and who want to sell their excess generation back to the grid.

RES has been widely promoted by the European Union (EU), where a series of goals have been set to reduce carbon emissions. To meet these, different supporting policies to back RES and PV self-generation have been put into place in most countries. The Spanish case deserves specific attention. A shifting regulatory environment and the 2008 financial crisis moved the country from encouraging RES deployment to a legally adverse scenario, where the government was putting legal and economic barriers up in a way of discouraging new project installations (Urbina, 2014). However, the new government has recently shifted this position to again engage with the energy transition.

In this paper, we present a study of the economic impacts on prices and market power that result from increased levels of PV-self-generation. We use a Nash-Cournot model of the Spanish electricity market to simulate profit-maximisation behaviour of all players in an imperfectly competitive market. This allows us to analyse the effects of solar self-generation on individual incumbents and on consumers in possible future scenarios. This information is highly relevant to policy, and necessary to inform the social debate around RES support.

We aim to make three contributions to the existing literature. First, we present a novel analysis that demonstrates how larger penetrations of rooftop PV reduce prices through a merit order effect, but also enhance competition in the market and reduce market power . To do so, a Nash-Cournot model is applied to a simplified representation of the Spanish electricity system. Second, our analysis illustrates that these two forces affect companies with different portfolios of generation in very different ways, which suggests one way to understand resistence to PV subsidies from incumbents. Third, we analyse the implications of larger deployments of rooftop PV on total amounts of thermal generation and associated GHG emissions in the Spanish system, taking into that energy demand is price-sensitive and therefore that solar self-generation is not wholly offsetting thermal electricity generation.

The remainder of this paper is structured as follows: Section 2 sets out the current state of the art. Section 3 outlines our mathematical methods. Section 4 deals with specific characteristics of the Spanish case study. Section 5 presents the results of our numerical analysis. Section 6 discusses these results, followed by a conclusion in Section 7.

2. Existing Literature

2.1. Impacts of RES on energy prices

Approaches to energy planning and policy require more sophisticated and analytical tools than the ones previously used to model other sectors (Munasinghe and Meier, 1993). Over the years, modelling has proved its usefulness, and it has been widely used as a decision support tool. However, it is important to consider that models are all based on simplifications, assumptions and often require data which may not exist. Whilst they are extremely powerful tools to analyse different policy options and economic trends, their results must not be taken as undeniable truths. It is important to highlight how an inaccurate description of energy problems might lead to inappropriate policy recommendations and actions (Bhattacharyya and Timilsina, 2010).

The effects of a high penetration of RES on prices in liberalised electricity markets have been studied extensively. Most of these markets, which were traditionally ruled by an established merit order, have seen the entrance of new competitors with lower marginal costs which has pushed traditional technologies out of the margin. The entrance of RES, historically boosted with subsidies, has generated an intense and controversial debate. These studies have mainly focused on the analysis of national or regional markets such as Germany and Austria (Tveten *et al.*, 2013; Würzburg and Linares, 2013; Cludius *et al.*, 2014; Ederer, 2015), Australia (McConnell *et al.*, 2013), Israel (Milstein and Tishler, 2011) or Italy (Clò, Cataldi and Zoppoli, 2015; Gullì and Balbo, 2015). These studies have approached the issue mainly through simulation based models and statistical analysis.

Simulation methods have focused on estimating the reductions in prices due to the merit order effect mentioned above. For instance, McConnell *et al.* (2013) state that policy incentives have produced net gains if wholesale price reductions and financial support is accounted for. Cludius *et al.* (2014) show how the merit order effect overcompensates some privileged groups of large consumers while negatively affecting domestic consumers. On the other hand, statistical analysis have been mainly based on econometric models such as Gelabert and Linares (2011), who perform an *ex post* analysis of the influence of renewable energy on the wholesale market prices.

The case of Spain has been widely studied due to its pioneering role in promoting large-scale deployment of solar PV. The Spanish government, in 2007, created a scheme that granted investors an extremely attractive Feed-In-Tariff. This generated a boom for Solar PV in 2008 with almost 3 GW of new capacity installed, while the technology was perhaps not mature enough, generating an economic deficit (Azofra *et al.*, 2016). Along a similar line, another study from Azofra *et al.* (2015) concludes that while Spanish subsidies to wind power have saved costs to the whole system, solar PV subsidies have generated an increase in total costs. Another study reflects the decrease in prices and the reduction of price spikes due to larger RES deployment (Ballester and Furió, 2015). The merit order effect of wind energy in the Iberian market and its effect on domestic consumers was studied by Prata, Carvalho and Azevedo (2018), who also conclude that consumers benefit less from this effect. Finally, Gelabert and Linares (2011) argued the unsustainability of the subsidies in Spain due to low reductions in the wholesale prices compared with the cost of subsidies. However, they surmise that large firms were exercising market power to push prices up and compensate the impact of renewables. Therefore, the merit order effect that RES created was being eliminated throughout illicit practices, as the 25M€ fine imposed by the National Market Commission (CNMC by initials in Spanish) to a Spanish electricity utility due to price manipulations (CNMC, 2015b) also suggests.

Hence, the effect that imperfectly competitive markets have had in all of this has been mentioned but generally not included in studies. Not taking into account this characteristic might have led to misleading policy interventions (Gullì and Balbo, 2015). The literature around the effects of RES in imperfect markets is still scarce. Closest to this study, Milstein and Tishler (2011) simulated imperfect competition markets in Germany and the effect of RES in them. Cournot oligopoly models were used and their conclusions contradict the existing literature on the topic, showing how FITs may actually increase prices due to enhanced market power. Another analysis that takes into account imperfectly competitive markets is presented by Gullì and Balbo (2015). Here, the authors conclude that PV generation might produce immediate reductions in electricity prices. However, PV capacity is able to erode the market power that large firms are able to exert. We will see similar effects in our analysis below. All these studies remain at the macro level and do not analyse the effect that an increasing capacity of solar PV has on individual incumbent's revenues and therefore the attitudes to RES developments that each of them might have in the near future.

2.2. Modelling energy markets

Optimisation models are widely used to analyse energy markets. These generally assume that the market is perfectly competitive, among a number of other assumptions. Like many other markets, real-world power markets usually present a degree of market power. Depending on market design, firms may be able to deliberately congest the network, bid strategically and/or withhold generating capacity. These issues have an even greater impact in electricity markets then they would in others, as supply and demand must match at any time due to physical requirements and because there is limited scope for intertemporal arbitrage. This affects not only prices and firms' profits but also consumers' economic welfare, and can lead to efficiency reductions. (Gabriel *et al.*, 2013a).

Simple optimisation models cannot capture these effects, so more advanced models, based on game theory, have been developed. Defined as *"the study of mathematical models of conflict and cooperation between intelligent rational decision-makers"* (Myerson, 1991), game theory principles have been extensively applied to social science analysis. In particular, game theory has played a key role in the understanding of behavioural patterns of market players. Mathematically, they can be represented by equilibrium models, which are playing an increasingly important role in power market analysis. These equilibrium models assume that each player individually maximises its own objective, usually profit, and find a solution by simultaneously solving these optimisation problems for all players. They are a powerful tool that can be used to analyse a wide range of settings, including regulation and deregulation, imperfect competition, and other features of real-world electricity markets. They are, however, more complex to solve than simple optimisation problems, and are usually formulated as non-linear optimisation or feasibility problems, or as complementarity problems, as we will do below.

Within an equilibrium framework, assumptions have to be made about what it is that firms are maximising, and which variables they control. When analysing behaviour of firms, competition and economic trends in power systems, Nash-Cournot competition is most commonly assumed (Gabriel *et al.*, 2013a). In a Nash-Cournot equilibrium, firms maximise profits, deciding on their quantities of production. This concept has stood the test of time and has been used extensively since the liberalisation of electricity markets (e.g., Ramos, Ventosa and Rivier, 1998; Borenstein, Bushneil and Knittel, 1999; Hobbs, 2001; Borenstein, Bushnell and Wolak, 2002). Currently, this concept is still applied in many different power system applications such as the analysis of transmission infrastructure investment (Sauma and Oren, 2006); the integration of charging stations for electrical vehicles in large cities (Ma and Callaway, 2013) or the evaluation of the risk of supplying electricity in uncertain markets with high penetration on RES (Kannan, Shanbhag and Kim, 2013).

There are alternatives, including supply function equilibrium models and Nash-Bertrand models. Supply function equilibrium models, in which firms decide price and quantity combinations, work well in small networks but in large networks are very computationally expensive. Nash-Bertrand models assume that firms set prices rather than quantities. This is appropriate for some markets, but the specific features of electricity markets, in which long-term decisions are typically related to quantities, make Nash-Cournot models more appropriate. Agent-based models are also commonly used in energy applications, but these are more appropriate for simulating the behaviour of a large number of players (e.g., consumers) which cannot be assumed to be rational profit maximisers, as opposed to the small number of large industrial players in wholesale energy markets.

Although they are able to capture more details of real-world markets than simple optimisation models, Nash-Cournot models, like any other modelling approaches, cannot precisely predict prices in imperfect markets, since invariably some market detail is assumed away. Nevertheless, they are a crucial tool for gaining insights on behavioural modes, efficiency differences between players, price levels, and other market outcomes of market designs (Hobbs, Helman and Pang, 2001). Due to its wide range of application areas, many of these models have been developed and are still being developed (Zhang, 2010; Yang and Chung, 2012; Oliveira, 2015; Chen *et al.*, 2017; Helgesen and Tomasgard, 2018), and we will use this same approach in our analysis below.

3. Methodology

3.1. Model overview

The model presented here is a Nash-Cournot model, which we will use to analyse the effects of self-generation impacts on the wholesale electricity market. It is based on the Hobbs (2001) POOLCO model, and separately includes renewable generation and solar PV self-generation. Since the main intention is to understand market behaviour, some technical characteristics have not been included in the model. These include variable marginal costs, ramping constraints, reserve and future markets and the uncertainty of renewable output. Although it is still highly simplified, the model represents how actors use their market power to increase electricity prices above marginal costs. Nevertheless, we recognize that some authors (e.g., Munoz, Sauma and Hobbs, 2013) have shown that ignoring these technical characteristics may generate distortions in the economic and policy consequences for the power system. Our quantitative results, like the results of any modelling study, should therefore be used with care, and we will focus on the more general insights derived from them.

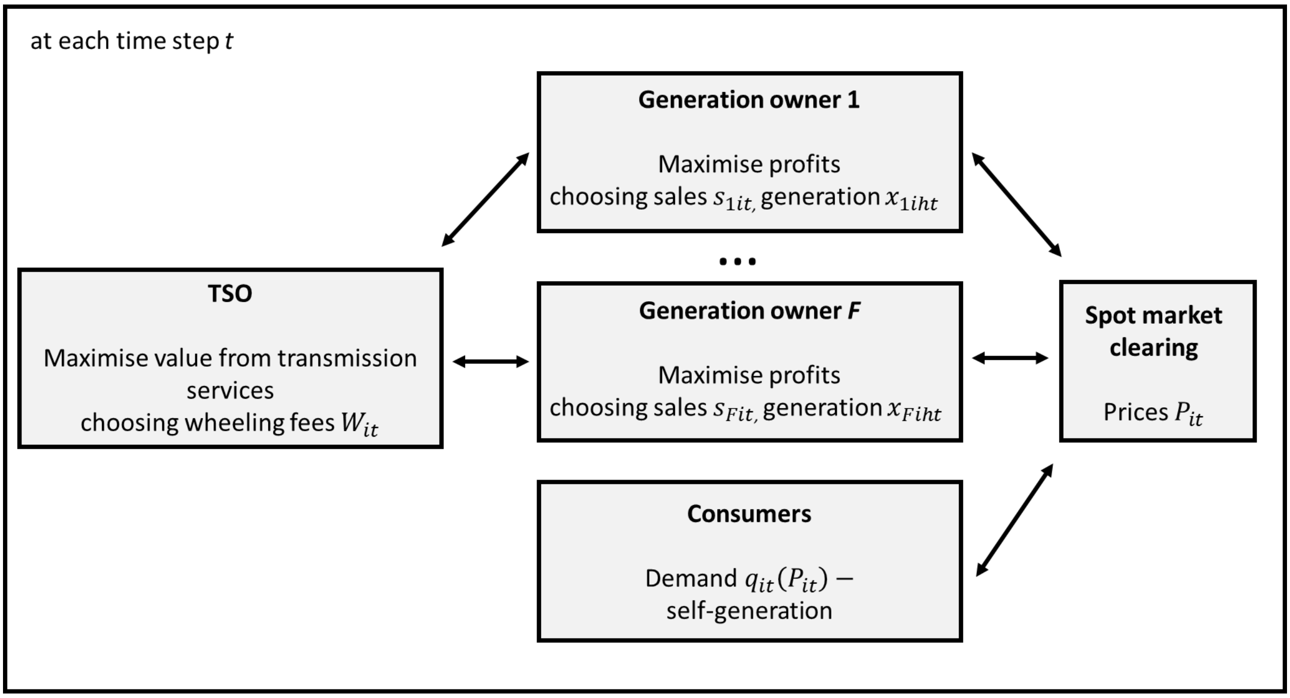

Figure 1 Block diagram of the POOLCO model.

In this model, each generation owner decides how much electricity to produce each hour, using its portfolio of power plants. Because of the computation expense of our modelling approach, we model representative 24-hour days, in this example the extreme cases of one winter and one summer day are presented. An exact quantification of prices would require more than three years of modelling, because of varying climates. However, this would be very computationally intensive without brining significantly more insight. Moreover, solar generation patterns, which are the key parameters in our model, are relatively regular and predictable in Spain, in comparison to other countries. Thus, in our spefici case, modelling two representative days, in the two extreme seasons of a year, is sufficient to establish the competitive and merit order effects of solar self-generation.

We use a Direct Current (DC) load flow approximation of a 12-node reduction of the Spanish high-voltage transmission network to approximate power flows. It is important to remark that the model proposed here considers that the network and generation infrastructure remains constant; that is, it ignores the transmission and generation expansion opportunities. Although expansion has an important relationship with market operation and can be included in game-theoretical (Sauma, 2009; Pozo, Contreras and Sauma, 2013; Pozo, Sauma and Contreras, 2017) we do not include them here, as the Spanish transmission network is relatively uncongested (and hence, transmission expansion would not significantly affect our results), while generation expansion is highly politicised and therefore cannot be modelled as an invidual generator's decision.

Demand is price-sensitive, with a low price elasticity. Variable renewable generation is modelled using historical hourly capacity factors. For simplicity, we assume a nodal pricing market, but since the Spanish system is relatively uncongested congested, this does not have a significant impact on our results; we present weighted average prices in our results. Section 3.2. below list our assumptions in detail.

3.2. Model assumptions

3.2.1. Network:

We estimate power flows using a linearised DC load flow approximation. Instead of including both Kirchoff's laws of current and voltage, linear equations approximate the flow in a DC version of the laws. This simplification is widely used in power economics modelling (Gabriel *et al.*, 2013b). It assumes that the line resistance is irrelevant compared with the reactance. Therefore, voltage magnitudes are equal to the nominal voltage level at all nodes. This implies that all nodes' voltages hover around 400 kV. We can then presolve for voltage angles and instead use PTDFs, power transfer distribution factors, which represent the increase in flow going through a line as a result of an injection of power in a node.

If the flow is defined as t_k, the total flow that is being transmitted through a line is represented by a summation of the electricity transmitted from each node i (y_i) and the $PTDF_{ik}$ of the combination of node and line:

$$\mathrm{t_k} = \sum_{\mathrm{i}} \mathrm{PTDF_{ik}} * \mathrm{y_i}, \qquad \forall \mathrm{k} \tag{1}$$

To take into account the system losses and the reactive power that is consumed in real-world AC networks, we increase demand by 3 %.

3.2.2. Generating facilities:

The generating facilities that have been taken into account in the model are: wind, hydro, nuclear, combined cycle gas turbines, coal, cogeneration and biomass, solar and self-generation. The complete list of generators has been aggregated by firm and node, such that every firm owns one generator of each type at each node, which represents the total amount of generation capacity of that type owned by the firm in that location. Ramping constraints have not been included; instead, in order to approximate the most important operational constraint in the Spanish system, minimum running levels have been included for nuclear generators. The minimum level at which nuclear plants can run in the model is 85% of their maximum capacity.

The marginal costs of the generating facilities are constant and only differentiated by type – they are not location or firm dependent. This approach has been used in other studies, as firm-level cost data is unavailable and plants using the same technologies can reasonably be assumed to behave similarly (Helgesen, 2018; Van der Weijde and Hobbs, 2012).

3.2.3. Demand:

We assume that demand is price-sensitive and linear in prices, (2) with a relatively low value for the slope, which has been established to be the case in the empirical literature (Bianco, Manca and Nardini, 2013; Chang *et al.*, 2014).

$$P_{it} = MD_{it} - \varepsilon_{it} * q_{it} \tag{2}$$

Spatiotemporally differentiated demand in the Spanish system is difficult to obtain. Hence, we apportion demand to the different nodes using constraint fractions, which are calculated using annual consumption data:

$$q_{it} = \%_i * Q_t, \forall it \tag{3}$$

Even though this is a simplification, the sizes of the consumption at each node are large enough to aggregate out any variation in demand structures because of regional variation in types of customers.

3.2.4. Renewable output:

The variability of the renewable output is modelled using hourly capacity factors, which are estimated using two years of historical data, validated against existing empirical studies (Boccard, 2009; REE, 2015, 2016, 2019). This is done individually for each node, since climate conditions differ between nodes. For computational convenience, a new parameter defined as Regional Variation (RV) is added. This parameter shows the deviation from the national mean capacity factor for each technology at each node.

$$\mathrm{RV_{ih}} = 1 + \frac{(\mathrm{CF}_{ih} - \overline{\mathrm{CF}}_{h})}{\overline{\mathrm{CF}}_{h}} \tag{4}$$

Therefore, the maximum hourly capacity of the renewable generator is constrained following (5). Since we are solving for electricity production over a relatively short time span, conventional generators have an hourly capacity factor equal to 1.

$$\mathrm{x_{fiht}} \leq \mathrm{RV_{ih}} * \mathrm{CF_{hi}} * \overline{\mathrm{X}}_{\mathrm{fiht}} \tag{5}$$

3.2.5. Self-generation

Since self-generation is generally non-dispatchable, we model it as an effective reduction in net demand, where capacity penetration levels are a percentage of demand. For instance, if the initial consumption in a node is 1000 MW, a level of 2% of penetration means that 20MW of solar PV is installed at the node. Apart from its non-dispatchability, self-generation is treated as any other renewable generating facility. Therefore, SG is subject to the same solar capacity factor and nodal deviation from the mean as dispatchable solar generation. Self-generation levels have been assessed from 0% up to 32%, this late number would account for around 10 GW of Solar PV between residential and commercial sector in the Spanish scenario, where some studies suggest that up to 16.5 GW of Solar PV could technically be installed (PwC, 2015).

3.3. Mathematical formulation

We assume that each firm f chooses electricity generation x_{fiht} at each of its type of generating facilities h at each node i and its sales s_{fit} at each node i, to maximise its profits at each time period t, where profit is defined as the difference between the revenues from electricity sales minus generation and transportation costs:

$$\text{MAX } \mathrm{B_i} = \sum_{\mathrm{i}} [(\mathrm{P_{it}} - \mathrm{W_{it}}) * \mathrm{s_{fit}}] - \sum_{\mathrm{i\,h}} [(\mathrm{MC_h} - \mathrm{W_{it}}) * \mathrm{x_{fiht}}] \tag{6}$$

Subject to:

$$\mathrm{x_{fiht}} \leq \mathrm{RV_{ih}} * \mathrm{CF_{ht}} * \overline{\mathrm{X}}_{\mathrm{fiht}} \quad (\rho_{\mathrm{fiht}}) \tag{7}$$

$$\mathrm{x_{fiht}} \geq \underline{\mathrm{X}}_{\mathrm{fiht}} \quad (\beta_{\mathrm{fiht}}) \tag{8}$$

$$\sum_{\mathrm{i\,h}} \mathrm{x_{fiht}} = \sum_{\mathrm{i}} \mathrm{s_{fit}} \quad (\theta_{\mathrm{ft}}) \tag{9}$$

$$\forall\ \mathrm{s_{fit}}, \mathrm{x_{fiht}} \geq 0 \tag{10}$$

Where P_{it} represents the price of electricity at the node i at the hour t, which is defined as:

$$\mathrm{P_{it}} = \mathrm{MaxP_{it}} - \varepsilon_{\mathrm{it}} * (\textstyle\sum_{\mathrm{i}} \mathrm{s_{fit}} + \mathrm{SG_{it}}) \tag{11}$$

$MaxP_{it}$ represents the maximum price at the node i at the hour t, ε_{it} represents the inverse demand function slope, and the consumption quantity q is assumed to be equal to the self-generated energy and the purchased energy in the node (equal to the sales). SG_{it} represents the amount of self-consumed energy, which is assumed to have a zero marginal cost and which can be or consumed or exported to the grid. This is the case in many countries, including Spain, which recently passed legislation specifying that self-generation can act as any other type of generation (BOE, 2018). W_{it} represents the transmission wheeling fee and MC_h is the marginal cost of generation, which is assumed to be constant and equal for generation facilities using the same type of energy source.

Regarding the constraints, $\overline{X}_{fiht}$ is the maximum installed capacity. The terms RV_{ih} and CF_{ht} are introduced to show the RES availability: CF_{ht} is the global capacity factor of RES in the system and RV_{ih} represents the variation in terms of RES availability between different nodes of the system. $\underline{X}_{fiht}$ is the minimum running level of a block of generators and ρ_{fiht}, β_{fiht} and θ_{ft} are the dual variables for the above mentioned constraints.

The producers' Karush-Kuhn-Tucker (KKT) conditions for the above problem are:

$$0 \leq \mathrm{s}_{\mathrm{fit}} \perp \mathrm{MaxD}_{\mathrm{it}} - \varepsilon_{\mathrm{it}} * \left(\mathrm{s}_{\mathrm{fit}} + \sum_{\mathrm{i}} \mathrm{s}_{\mathrm{fit}} + \mathrm{SC}_{\mathrm{it}} \right) - \mathrm{W}_{\mathrm{it}} - \theta_{\mathrm{ft}} \leq 0 \quad \forall\, i, t \tag{12}$$

$$0 \leq \mathrm{x}_{\mathrm{fiht}} \perp -(\mathrm{MC}_{\mathrm{h}} - \mathrm{W}_{\mathrm{it}}) - \rho_{\mathrm{fiht}} + \theta_{\mathrm{ft}} + \beta_{\mathrm{fiht}} \leq 0 \quad \forall\, i, h, t \tag{13}$$

$$0 \leq \rho_{\mathrm{fiht}} \perp \mathrm{x}_{\mathrm{fiht}} - \mathrm{RV}_{\mathrm{ih}} * \mathrm{CF}_{\mathrm{ht}} * \overline{\mathrm{X}}_{\mathrm{fiht}} \leq 0 \quad \forall\, i, h, t \tag{14}$$

$$0 \leq \beta_{\mathrm{fiht}} \perp \underline{\mathrm{X}}_{\mathrm{fiht}} - \mathrm{x}_{\mathrm{fiht}} \leq 0 \quad \forall\, i, h, t \tag{15}$$

$$\textstyle\sum_{\mathrm{i\,h}} \mathrm{x}_{\mathrm{fiht}} = \sum_{\mathrm{i}} \mathrm{s}_{\mathrm{fit}} \quad \forall\, t \tag{16}$$

We assume that the transmission system operator is a price-taker, which maximises revenues from providing transmission services, such that its maximisation problem is:

$$\mathrm{MAX}\ \sum_{\mathrm{i}} \mathrm{W_{it}} * \mathrm{y_{it}} \tag{17}$$

Subject to:

$$\sum_{\mathrm{i}} \mathrm{PTDF_{ik}} * \mathrm{y_{it}} \leq \mathrm{MF_k} \quad (\lambda_{\mathrm{kt}}^{+}) \tag{18}$$

$$-\sum_{\mathrm{i}} \mathrm{PTDF_{ik}} * \mathrm{y_{it}} \leq \mathrm{MF_k} \quad (\lambda_{\mathrm{kt}}^{-}) \tag{19}$$

Where y_{it} represents the flow on each line transmitted to the node i, MF_k represents the maximum thermal capacity of each line k and λ_{kt} represents the dual variable associated with the maximum and minimum flow constraints on the lines. Therefore, the KKT conditions for the grid owner are:

$$\mathrm{W_{it}} + \sum_{\mathrm{k}} \mathrm{PTDF_{ik}} * (\lambda_{\mathrm{kt}}^{-} - \lambda_{\mathrm{kt}}^{+}) = 0 \quad \forall\, i, t \tag{20}$$

$$0 \leq \lambda_{\mathrm{kt}}^{+} \perp \sum_{\mathrm{i}} \mathrm{PTDF_{ik}} * \mathrm{y_{it}} - \mathrm{MF_k} \leq 0 \quad \forall\, k, t \tag{21}$$

$$0 \leq \lambda_{\mathrm{kt}}^{-} \perp -\sum_{\mathrm{i}} \mathrm{PTDF_{ik}} * \mathrm{y_{it}} - \mathrm{MF_k} \leq 0 \quad \forall\, k, t \tag{22}$$

Finally, a transmission market clearing constraint must be satisfied, which specifies that the supplied transmission capacity is equal to demand for transmission:

$$\sum_{f} s_{fit} - \sum_{fh} x_{fiht} = y_{it} \quad \forall\, i, t \tag{23}$$

4. Case Study: Spanish market

Since 1998, the Spanish electricity sector has been restructured according to the Electricity Sector Act 54/1997. This act aimed to introduce competition into both electricity generation and retail markets. On the other hand, transmission and distribution are natural monopolies and remain highly regulated markets. Although liberalised, the Spanish electricity market presents a distinctive model since it permits vertically integrated firm holdings with generation, distribution and retail services (Ciarreta, Nasirov and Silva, 2016).

Currently, the Spanish generating market is dominated by three main firms, Endesa, Gas Natural Fenosa (recently renamed to Naturgy) and Iberdrola. Each hold more than 12% of the market share, and combined the three firms were responsible for 60% of the generating capacity, 55% of the generated electricity and 80% of the retail market during 2014 (CNMC, 2015a). EDP and Viesgo (owned by the German firm E.ON) are the other two main players on the market. They each own more than 5% of the generating capacity and have a strong position on the retail market.

The electricity is traded in a joint market with Portugal (MIBEL). The preferred marketplace for electricity transactions is a *day-ahead market*, often referred to as *spot market*. This market represents more than 70% of the total purchased electricity of Iberian market (OMIE, 2016), while the future market represents only 30% and contracts are normally indexed to spot prices. The market works as a two-sided auction, where producers submit offers for delivering electricity at a certain price and time of the next day and are merged by the Market Operator with a marginal pricing system. This market is regulated and transparent. However, market power has been still been observed.

Market power has been legally proven, as deponstrated by, for instance, a fine imposed in 2015. The CNMC (National Commission on Markets and Competition) fined an electricity utility €25M for voluntary curtailing hydro production to obtain higher prices in the spot market (CNMC, 2015b). This market power in the Spanish sector has been widely studied since the creation of the liberalised market. Fabra and Toro (Fabra and Toro, 2005) conclude that Spanish generating firms were probably engaged in tacit agreements to distort the market outcomes. Ciarreta & Espinosa (Ciarreta and Espinosa, 2010) find that larger operators were able to increase considerably the prices above competitive levels. And, Nuño *et al.* (Nuño, Pereira and Machado, 2015) show how an increasing wind penetration on this market has shifted some of the market power of these firms to the capacity market.

Physically, Spain has a large and well-diversified generation system. The system has a high reliability and has successfully integrated a large share of RES with little generation curtailment (IEA, 2015). The Spanish network is characterised by its robustness. The transmission network has a large degree of reliability and flow constraints are not normally binding (Dietrich *et al.*, 2015). Even though the internal system is highly reliable, since the Iberian Peninsula has a low cross-border capacity (IEA, 2015), any intermittency in the Iberian system must be dealt within the region. Therefore, the Iberian electricity system operates almost as an island in Europe.

4.1. Input data

In order to reproduce the Spanish market, we use a reduced network model that only covers the 400 kV lines in Spain. These lines are the major source of transport capacity in the peninsula with 21,094 km of lines installed at the end of 2014 (REE, 2015). The initial network data was obtained from a model of the European network (Neuhoff *et al.*, 2013). The Spanish nodes have been reduced to 12 nodes, one for each Spanish region, with the exception of the “North” node, which contains Asturias and Cantabria, and “Basque Country”, which groups the Basque Country, Navarra and La Rioja. These 12 nodes are connected with 23 lines. These nodes have been chosen because they provide enough detail to analyse the Spanish system for the purpose of policy making. By aggregating generators and loads by region, reliable data from the TSO is available. The extra peninsular systems (islands) and international connections have not been considered. Therefore, Portuguese, French and Moroccan generation and consumption have not been taken into account. To model the system, PTDFs have been calculated using a lossless DC approximation of the network and taking Andalucia as the slack bus; the resulting data is presented in Table 1.

Table 1 PTDFs, Spain 12 node system

PTDF	Andalucía	Aragon	Castilla LM	Castilla Leon	Cataluña	Extremadura	Galicia	Madrid	Murcia	Norte	País Vasco	Valencia
L1	-	- 0,364	- 0,301	- 0,422	- 0,359	- 0,667	- 0,422	- 0,399	- 0,238	- 0,422	- 0,410	- 0,302
L2	-	- 0,195	- 0,200	- 0,172	- 0,198	- 0,097	- 0,172	- 0,175	- 0,378	- 0,172	- 0,177	- 0,230
L3	-	- 0,456	- 0,507	- 0,416	- 0,461	- 0,240	- 0,416	- 0,434	- 0,391	- 0,416	- 0,425	- 0,477
L4	-	0,200	0,028	- 0,144	0,195	- 0,032	- 0,146	- 0,025	0,030	- 0,142	- 0,072	0,054
L5	-	0,146	- 0,007	0,075	0,131	0,017	0,075	0,016	- 0,023	0,075	0,090	- 0,055
L6	-	0,230	0,032	- 0,165	0,224	- 0,037	- 0,168	- 0,029	0,034	- 0,171	- 0,295	0,062
L7	-	0,117	- 0,022	0,079	- 0,842	0,021	0,086	0,012	- 0,035	0,084	0,091	- 0,088
L8	-	0,307	- 0,031	0,154	0,289	0,031	0,153	0,026	- 0,007	0,155	0,186	0,027
L9	-	0,084	0,128	0,087	0,081	0,055	0,087	0,102	- 0,383	0,087	0,087	0,032
L10	-	0,021	0,033	0,010	0,022	- 0,036	0,010	0,014	0,025	0,010	0,012	0,029
L11	-	- 0,203	0,093	- 0,085	- 0,247	- 0,003	- 0,084	0,016	- 0,182	- 0,086	- 0,110	- 0,651
L12	-	- 0,058	0,209	- 0,278	- 0,038	- 0,226	- 0,279	- 0,541	0,143	- 0,277	- 0,232	0,139
L13	-	0,243	- 0,023	0,461	0,225	0,024	0,462	- 0,139	- 0,006	0,460	0,415	0,018
L14	-	- 0,005	- 0,001	0,003	- 0,001	0,001	- 0,052	0,001	- 0,001	- 0,933	- 0,029	- 0,001
L15	-	0,004	0,001	- 0,003	0,007	- 0,001	- 0,954	- 0,001	0,001	- 0,035	- 0,003	0,001
L16	-	0,171	0,080	0,245	0,166	- 0,089	0,245	0,088	0,067	0,245	0,230	0,092
L17	-	- 0,217	- 0,030	0,155	- 0,209	0,035	0,156	0,027	- 0,032	0,125	- 0,682	- 0,058
L18	-	0,189	- 0,008	0,095	0,262	0,021	0,094	0,021	- 0,028	0,095	0,115	- 0,066

L19	-	-0,183	-0,191	-0,173	-0,185	0,211	-0,172	-0,299	-0,149	-0,173	-0,175	-0,185
L20	-	-0,000	-0,000	0,000	-0,001	0,000	0,057	0,000	-0,000	-0,031	-0,001	-0,000
L21	-	-0,005	-0,005	0,008	-0,008	0,009	0,009	0,023	-0,013	0,008	0,006	-0,031
L22	-	-0,119	-0,073	-0,090	-0,129	-0,043	-0,090	-0,075	0,246	-0,090	-0,096	-0,199
L23	-	-0,009	-0,001	0,007	-0,009	0,002	0,009	0,001	-0,001	0,044	-0,028	-0,002

We only model the firm-specific strategic behaviour of Iberdrola, Endesa, Gas Natural (recently renamed to Naturgy, but still operating under its old name during the modelled period), E.ON, EDP and GDF Suez, since the rest of the facilities are owned by a large number of smaller firms. In order to include the behaviour of these firms, we group them into five renewable energy firms, each with a 3% market share. This allows the model to include all renewable generation without giving these aggregate firms significant market power. In a similar way, a catch-all firm representing all the thermal generation not owned by the main electricity utilities has been created (named “Other Thermal” in the results). Firms have very different portfolios of generation. These are presented in Table *2* and have been estimated using a number of sources (REE, 2015; Acciona, 2016; EDP, 2016; Endesa, 2016; Gas Natural, 2016; Iberdrola, 2016).

Table 2: Firms’ portfolio by source

	Acciona	**E.On**	**EDP**	**Endesa**	**Gas Natural**
Coal	0%	19%	52%	27%	20%
Nuclear	0%	0%	0%	17%	0%
Wind	80%	6%	3%	9%	0%
Hydro	15%	15%	15%	26%	17%
CCGT	0%	60%	30%	21%	63%
Solar	4%	0%	0%	0%	0%
Cogeneration	1%	0%	0%	0%	0%
% of total	6.56	5.33	3.21	20.25	12.32

	GDF Suez	**Iberdrola**	**Other Thermal**	**Other RES I, II, III, IV**
Coal	0%	3%	9%	0%
Nuclear	0%	16%	0%	0%
Wind	0%	21%	0%	67%

Hydro	0%	38%	0%	0%
CCGT	100%	21%	91%	0%
Solar	0%	0%	0%	33%
Cogeneration	0%	1%	0%	0%
% over total	2.23	29.64	3.78	3.34

For instance, while Acciona and the aggregated small renewable generation owners ("Other RES") have only renewable facilities; E.ON, EDP, GDF Suez, Gas Natural and Other Thermal have a portfolio based on thermal generators and hydro. Iberdrola and Endesa have a well-diversified portfolio of generating facilities. The marginal cost (MC) of each generation technology is based on (Van der Weijde and Hobbs, 2012) and translated to current prices. This is an obvious simplification, as in reality different plants using the same fuel may have slightly different fuel costs. Moreover, specific studies in Spain like Ciarreta, Espinosa and Pizarro-Irizar (2017) show inelastic supply offers from technologies like coal, nuclear, and hydro. However, as previously mentioned, detailed marginal cost information for individual power plants is confidential and cannot be accessed.

Table 3 Marginal costs by energy type

MC	**€/MWh**
Coal	20,54
Nuclear	2,15
Wind	0,01
Hydro	1,95
Gas	35,8
Solar	0,01
Cogeneration	11,85

Although there is no wide variety of energy demand studies for Spain, there is evidence that the electricity demand is relatively inelastic (Labandeira, Labeaga and López-Otero, 2012; Blázquez, Boogen and Filippini, 2013; Perez-García and Moral-Carcedo, 2016). The elasticities estimated in these studies vary between 0.05 in the short term, to 0.21 in the long term. We use a linear demand function with a slope of 0.07, similar to (Labandeira, Labeaga and López-Otero, 2012).

Energy demand data for each node, as a fraction of total Spanish demand, was obtained from (REE, 2015) and is presented in Table *4*.

Table 4: Percent demand by node

Node	**Demand**
Andalucia	15.61%
Aragon	4.05%
Castilla la Mancha	4.59%
Castilla Leon	5.31%
Catalunya	19.00%
Extremadura	1.76%
Galicia	7.99%
Madrid	11.84%
Murcia	3.52%
Norte	6.01%
Pais Vasco	9.57%
Valencia	10.76%

The regional variations considered for the different renewable sources can be seen in Table *5*, which are retrieved from (Boccard, 2009; REE, 2015). Finally, hourly historical capacity factors were retrieved from the REE database (REE, 2016).

Table 5: Nodal regional variations by source

Node	Wind	Hydro	Solar
Andalucia	0.980	0.488	1.172
Aragon	1.048	1.225	1.022
Castilla la Mancha	0.920	0.684	1.082
Castilla Leon	0.876	1.313	1.022
Catalunya	0.847	1.225	0.932
Extremadura	0.992	0.488	1.142
Galicia	1.048	1.280	0.811
Madrid	1.000	1.000	1.052
Murcia	0.787	0.684	1.142
Norte	0.968	1.280	0.721
Pais Vasco	1.229	1.280	0.721
Valencia	0.964	0.684	1.052

We consider two days with identical levels of self-generation: a typical winter day (a working day in February 2014) and a typical summer day (a working day in July 2014). The variations between these two scenarios is considerable, due to the climatic characteristics of Spain and its spatial location (an average latitude of 40 degrees), with long summer days and short winter days, which will significantly affect PV performance. The winter day is characterised by only 5 hours of sunlight. Moreover, the intensity of the sun is relatively low and solar capacity factor is around 30% of its nominal value at solar noon. Figure 1 shows the winter demand curve (not including reductions due to solar self-generation) and the hourly solar capacity factor.

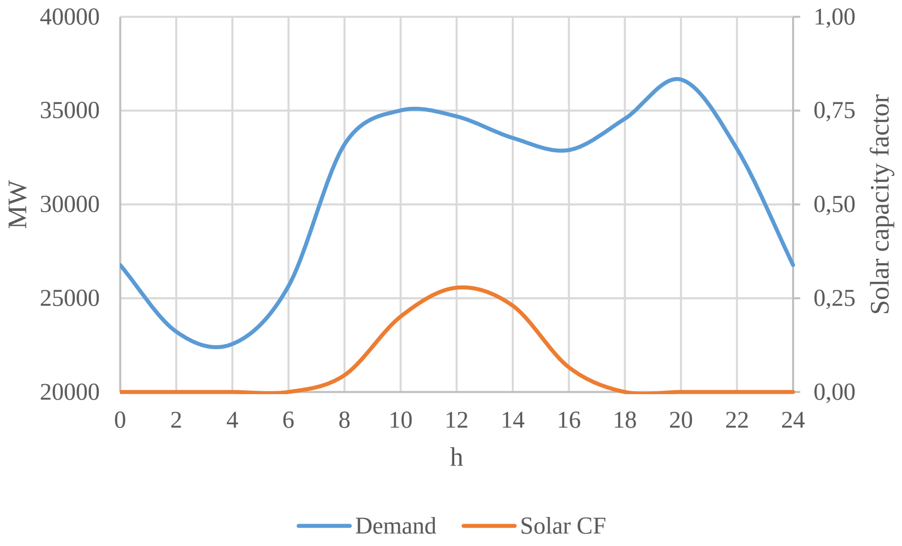

Figure 2: Winter demand curve.

During the summer period simulation, the sun shines between 7am until 10pm. In addition, the levels of irradiation are much higher than the ones experienced in winter. Figure 2 shows the summer demand curve.

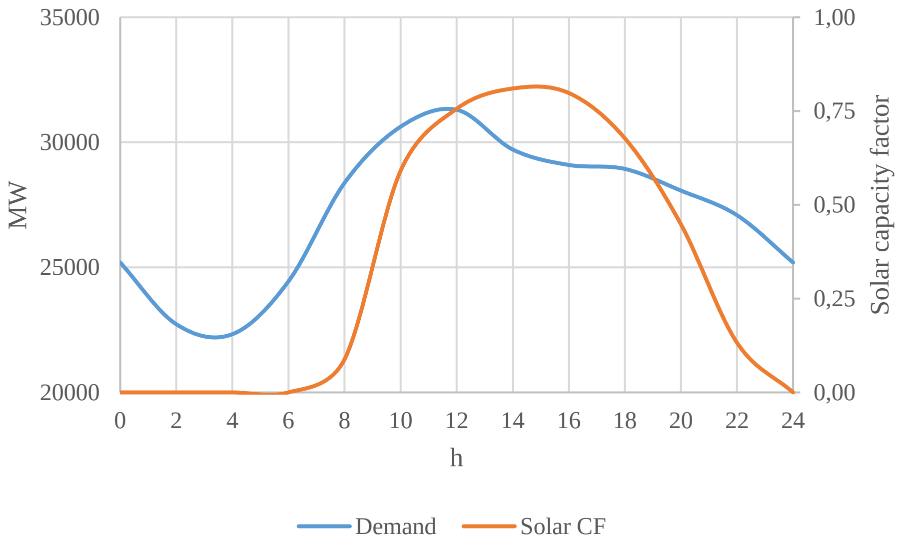

Figure 3: Summer demand curve

5. Results and Discussion

5.1. Overall results

This section presents the results and discussion of the Spanish market response to an increasing level of self-generation. As explained above, we will consider a typical winter day and a typical summer day. Although there are important differences between the two days, in both seasons the market experiences similar qualitative responses to self-generation. In general terms, the competitiveness of the market is enhanced, since both prices and market concentrations decrease. As the penetration of solar self-generation increases, prices move significantly closer to the marginal cost of the last unit dispatched (CCGT).

The overall consumption of electricity, including self-generation and centrally produced electricity, increases. In contrast, less electricity is purchased from the grid. The reduction in purchases is lower than the self-generated electricity since lower prices incentivise consumers to purchase more. This rebound effect reduces the carbon savings of self-generation, but represents an increase in consumer utility and, in the longer run, better living standards and economic performance.

Finally, as self-generation increases, the affected large-scale generators are mainly thermal plants, which have a higher marginal cost. There is little impact on centralised renewable energy output. On the other hand, some low marginal cost generators, including mainly hydro and some nuclear plants, have their output reduced, partly in an effort by firms to maintain higher prices. The voluntary curtailment of hydro, which as explained above has been observed in the Spanish market, represents some evidence that the model does reflect the realities of the Spanish market reasonably well.

5.2. Winter day

The winter day is characterised by only 10 hours of sunlight. Moreover, the intensity of the sun is relatively low and the solar production is around 30% of its nominal value at solar noon. In general terms, average daily prices are reduced by 2% with a 32% of SG penetration. The baseline price without

SG is €51.5 per MWh, a price similar to the average price on the Spanish market the modelled day (€50.3 per MWh).

Average daily consumption goes up by less than 1-2%, even at very high SG penetrations, mostly due to the low price elasticity of demand. However, there is a larger increase in consumption during the hours with sunlight, increasing the correlation between energy availability and consumption.

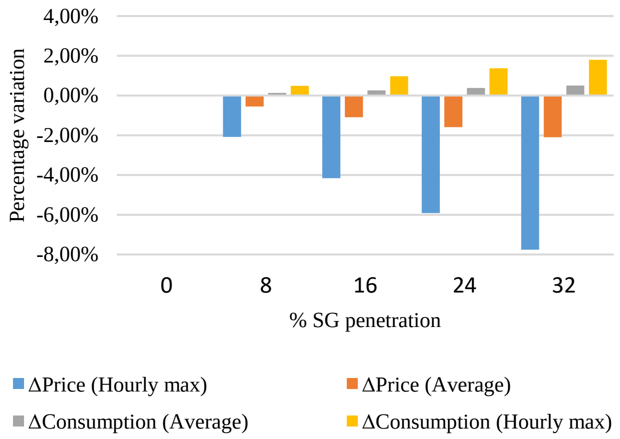

Figure 4: Price and consumption variations. Winter day.

Figure *5* shows the levels of consumption and electricity purchased from the grid at different levels of SG. Only sunlight hours are shown, as there is no change when it is dark. As it can be seen in the figure, as the amount of SG increases the amount of electricity purchased from the grid decreases, whereas the overall consumption increases. This occurs because consumption of zero marginal cost electricity decreases wholesale market prices through a merit order effect and decrease in market power. The variations in consumption and purchases are largely dependent on the assumed elasticity of the Spanish consumers.

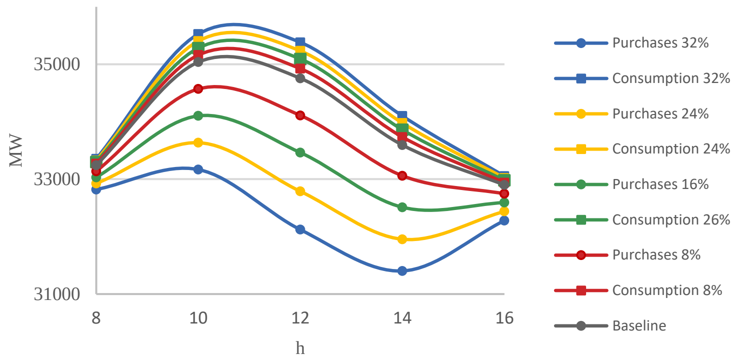

Figure 5: Electricity consumption and purchases from the grid at different levels of SG penetration. Winter day.

Delving deeper in to these results, Figure *6* and Figure *7* show the percentage reductions in generation and profits of the various incumbents. It is important to note that these are future projections obtained from a highly stylised model: we are not accusing any of the firms mentioned of current or future anti-competitive behaviour beyond what has been legally established so far, but simply highlighting what would happen if they responded only to economic incentives.

In terms of generation by firm, the firms with an exclusively renewable generation portfolio are not affected in terms of production; they experience no merit order effect, and have little market power to begin with. This can be seen with the aggregated producer Other RES and Acciona. Naturally, these producers still see lower profits because of a reduction in prices. On the other hand, the firms that only own thermal units, such as GDF Suez, Other Thermal, E.ON and EDP, are the ones most affected; they are more likely to be pushed out of the margin, and lose market power. Although they have gas and coal facilities, Endesa and Iberdrola mainly rely on their nuclear and RES to produce electricity, since these have lower marginal costs. Hence, Iberdrola manages to hold on to its market share and keep its profits high by reducing its output to maintain higher prices. Endesa is not affected during the winter period since it benefits from Iberdrola's capacity withholding. It is necessary to highlight that the decrease in generation never exceeds 10% for a single firm, despite increasing SG up to 32%. Profits decrease more, but still only by a modest 11% in the worst case. This is significant, but unlikely to have immediate solvency consequences for the firms concerned.

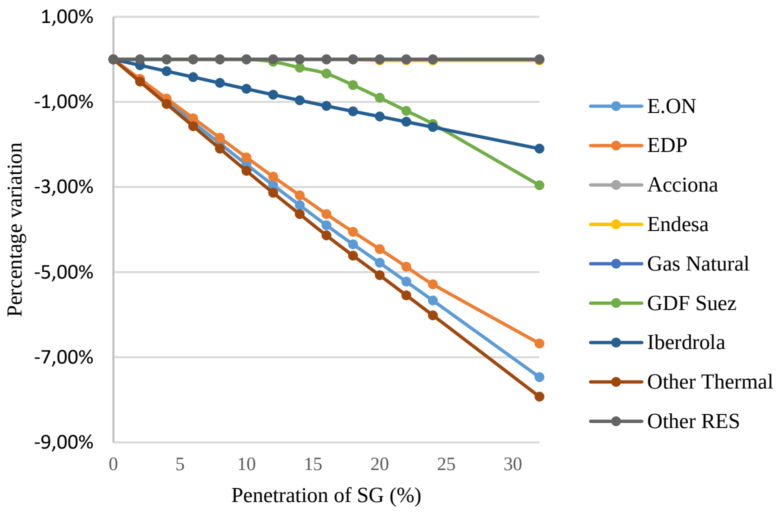

Figure 6: Reduction of firms' generation. Winter day.

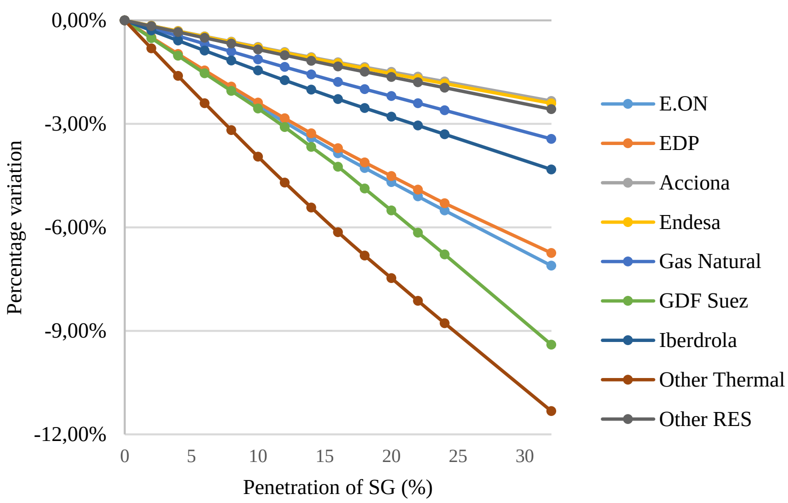

Figure 7: Reduction of firms' profits. Winter day.

In terms of generation by source, the following figures represent the hourly generation by source. Starting from the winter baseline scenario without SG in Figure 7, a scenario with 32% of SG capacity penetration with respect to the maximum hourly demand is pictures in Figure 8. Between 8am and 16pm, SG reduces conventional generation. CCGTs are rapidly curtailed by firms with other generating sources in their portfolio. The high marginal of this technology makes it less attractive with prices getting closer to marginal cost. Another interesting feature is that the other source curtailed is hydro, despite having a lower marginal cost than coal. This happens because these hydro plants belong to Iberdrola, the largest player in the market, which cuts their output to maintain higher prices. This has happened in reality, with fines being imposed on hydro curtailing.

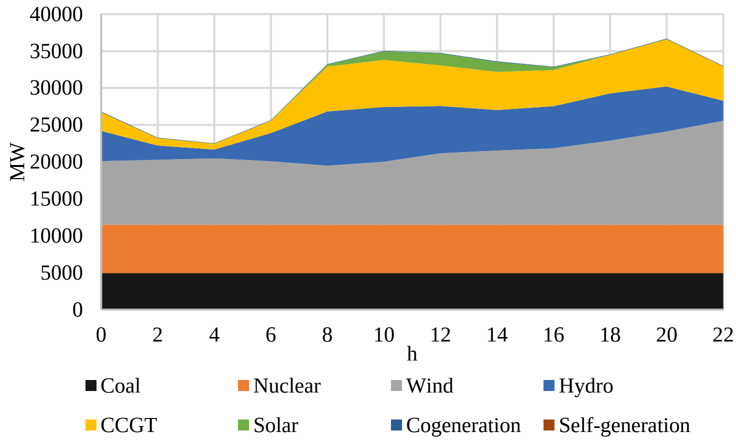

Figure 8: Generation by source. Baseline scenario. Winter day

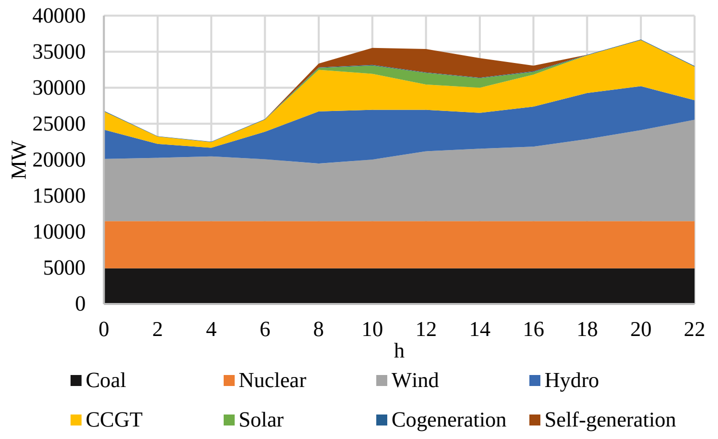

Figure 9: Generation by source. 32% SG winter day

Although the solar resource is poorer in winter, wind and hydro resources are better. Consequently, the hour-to-hour variation in winter market prices does not change substantially with the introduction of SG.

5.3. Summer day

The effects that occur in summer are similar to the ones occurring in winter but are larger in magnitude. This happens because, in summer, the sun is up between 7am until 10pm; a much longer period. In addition, the levels of irradiation are much higher than the ones experienced in winter. Summer demand, on the other hand, is lower. Consequently, the effects of SG prices and consumption are almost five and seven times higher, respectively. Price reductions accentuate the competitive differences between firms: some of them are pushed out of the market almost completely, while others are able to resist the downwards pressure on profits.

The effects of an increase in SG penetration on prices and consumption are presented in Figure 10. It is interesting to point out that the maximum variations on hourly prices result in prices below the marginal cost of a gas-fired power plant, driving this technology completely out of the market during most of the day. In this case, overall consumption grows by 1-4% on average, because, even though the price elasticity is demand is low, the large solar potential that Spain has during summer months leads to a substantial reduction in prices.

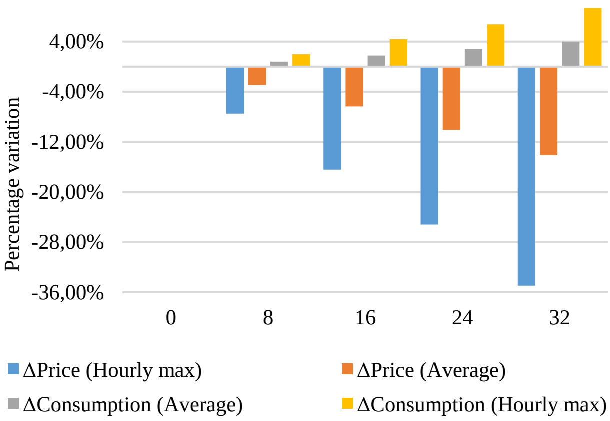

Figure 10: Price and consumption variations. Summer day.

Figure 11 shows purchased and consumed electricity. The purchases from the grid tend to reduce rapidly during daytime hours. Moreover, a high penetration of SG therefore significantly changes consumption patterns. Low electricity prices during the day lead wholesale consumers to behave differently, concentrating electricity consumption during peak hours and reducing consumption during night hours. In the longer term, having SG and low-cost electricity can perhaps make consumers more price responsive (e.g., through households becoming price responsive, in addition to the already responsive industry) and change the inelasticity of electricity demand. Additional studies should be undertaken in the area in order to analyse the long-term effects of changing price patterns.

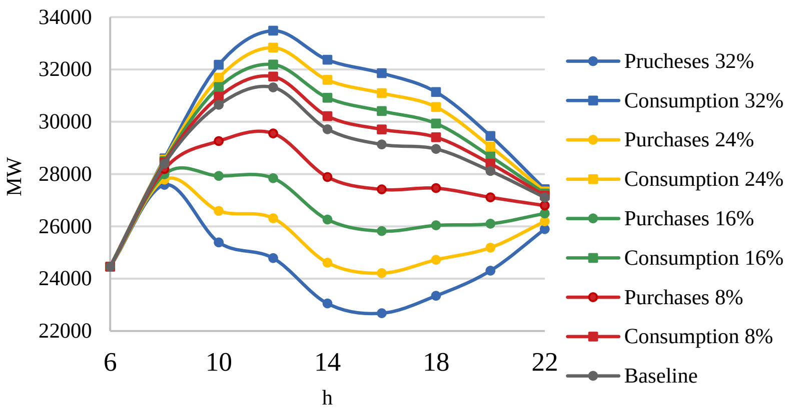

Figure 11: Electricity consumption and purchases at different levels of SG penetration. Summer day.

The generation profiles by firm shown in Figure *12* follow a similar trend to the one experienced in winter but, again, with a larger magnitude. In this case, Endesa does not just free ride on Iberdrola's capacity withholding but reduces its own generation to maintain higher prices. In terms of production, all firms are now affected to some extent, except the ones with only RES on their portfolio. Their zero marginal cost allows them to dispatch all their available electricity even though prices have come down. Although all firms follow a decreasing trend, each firm presents particularities depending on their specific portfolio. Gas Natural starts to decrease its generation with 20% of SG penetration. E.ON stops decreasing its output at around a 21% decrease, which occurs at a 24% SG penetration. On the other hand, Endesa and Iberdrola present a linear trend, a behaviour based on maintaining the prices high to maximise their profits.

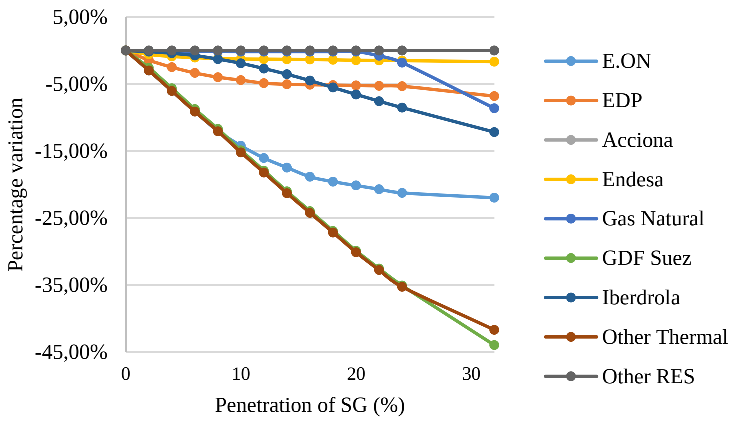

Figure 12: Reduction of firms' generation. Summer day.

Changes in profits can be found in Figure 13. This figure shows how the firms that only own thermal generators are almost driven out of the market since their profits are reduced by 50%. The rest of the players face a reduction of profits of around 20%. While Acciona only loses 15% of its profits, E.ON sees them reduced by 28%.

Three main conclusions arise from these results. First, the figures show the market power that firms currently have. Facing reductions of 12% in prices and reductions of around one third of the sales, most are, in all likelihood, still able to stay in the market and only see their profits reduced by less than a quarter. Secondly, if price reductions are passed down to end users, along with the increase of "free"self-generation, expenditure on electricity will decrease significantly. This effect follows the economic belief that as markets gets closer to perfect competition, consumer surplus is increased. Finally, if the idea of having a liberalised market is to enhance market efficiency, the implementation of SG proves to be a measure that aligns with this objective. Increasing levels of SG bring prices closer to marginal costs, which itself decrease, enhancing efficiency in the sector.

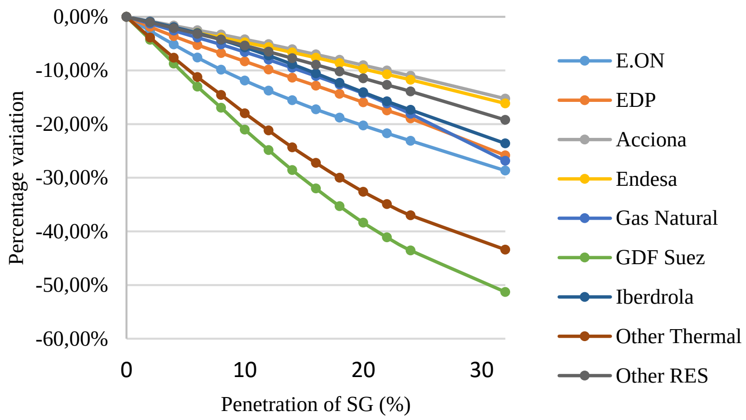

Figure 13: Reduction of firms' profits. Summer day.

Figures 13 and 14 show how the generation mix changes as a result of a high SG penetration on a summer day. Compared to the winter day, wind and hydro generation have a lower contribution in the electricity mix while solar has a higher contribution due to seasonal effects. As renewable sources other than PV produce less in summer and the demand is lower than in winter, the share of nuclear generation is increased.

When SG starts to penetrate in the system, CCGTs are rapidly removed from the mix. At 32% of penetration, CCGTs are no longer generating. Here, the price of electricity is below the marginal cost of gas-fired generators. The other source that reduces its output is hydro. As previously mentioned, Iberdrola, Endesa and Gas Natural reduce their output by reducing hydro production. In terms of coal production, it is not until a 24% SG penetration that a reduction in coal production can be seen. Coal's marginal cost is still competitive at low market prices and many firms rely on these producing facilities to generate profits.

Hence, coal use is reduced less than gas use. This has a major implication in terms of GHG emissions since coal emits more than gas and, obviously, than hydro. Nevertheless, the majority of reduction in generation takes place in sources that emit GHGs. Consequently, a higher SG penetration would not only enhance competition and reduce prices, but also reduce the GHG emission of the electricity sector.

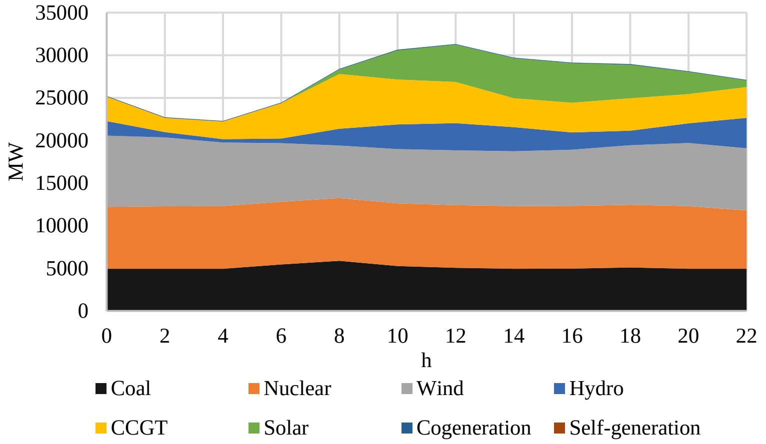

Figure 14: Generation by source. Baseline scenario. Summer day.

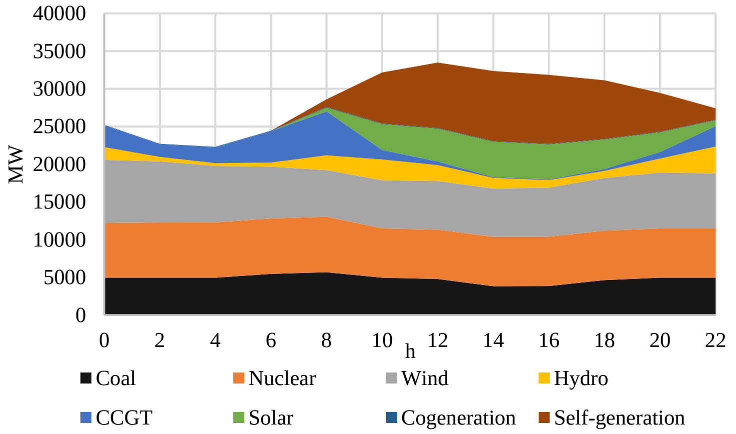

Figure 15: Generation by source. 32% SG scenario. Summer day.

To sum up, the results obtained from the model that simulates the Spanish electricity system with increasing levels of solar SG have been presented for both a winter and a summer day. The effects occurring in summer and winter are similar in qualitative terms but with a larger quantitative impact during the summer period. These effects can be summarised in four main points:

1. The deployment of SG enhances competition and reduces wholesale market prices.

2. SG does create some rebound effects. Increasing levels of SG results in increasing levels of electricity consumption, but grid electricity demand is reduced.

3. Firms with a high percentage of RES on their portfolio are less affected than the ones that mainly rely on thermal generators, although even those that rely on thermal generators are affected differently depending on their current market power.
4. SG reduces thermal generation. Consequently, GHG emissions are reduced as well.

Our base case results are consistent with historical prices; given historic demand data, prices are never more than 5% from their actual levels.

6. Conclusions and Policy Implications

In this paper, the impact of increasing levels of self-generation on the wholesale electricity market have been studied and the Spanish market has been used as a case study. This market is characterised by market power and a generally negative attitude towards self-generation developments because of strong lobbying by incumbents. A Nash-Cournot model has been used to simulate the market with different scenarios of SG penetration to consider their effects on prices, electricity demand and profits of different incumbents.

The result of the study shows how an increase in self-generation reduces prices in two ways: through a merit-order effect and through a reduction in market power. Hence, although it is positive for consumers, it is understandable that the incumbent electricity suppliers are not enthusiastic about increasing the SG penetration. However, as we have also shown, the effects are far from uniform and affect different incumbents differently. Moreover, even if SG capacity was expanded to account for up to 32% of the peak hour demand as modelled in the maximum case the total SG electricity would still be less than 15% of the total market. Increasing SG does change the market but is not a radical reshaping of the current status quo.

Moreover, the presented results suggest that the usage of complementarity models in the analysis of self-generation provides valuable insights. Results like those above can contribute to the social discussion about the desirability of SG developments, and increase transparency about who wins and who loses. In addition, analyse if these losses are just correcting a current market failure (if they originate from reduced market power) or originate from fundamental changes in the cost structures of the market (in the case of a merit order effect).

Further research remains essential. There are many opportunities to further refine this type of analysis This can range from increasing the detail in the model such as more nodes and more firms as well as introducing new features like demand alignment or ramping constraints. It is particularly recommended that in addition to the variability of RES and SG, its stochasticity is incorporated into the model and that the modelling of behaviour of the market players is considered carefully and include new policy constraints that address these issues. Future developments should implement a more complex and realistic situation showing the particularities of markets. In terms of self-generation, behavioural patterns as demand alignment with generation or technicalities such as the installation of batteries could be included too. Nevertheless, the above analysis presents a first attempt to quantify how self-generation affects imperfect electricity markets.

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