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Preface

Between February 4 and 5, 2016, The Lisbon Superior Engineering Institute (ISEL) held the 1st Energy Economics Iberian Conference (EEIC 2016), organized by the Portuguese Association of Energy Economics (APEEN) in close collaboration with the Spanish Association of Energy Economics (AEEE), the Lisbon Superior Engineering Institute (ISEL) and the Research Unit in Governance, Competitiveness and Public Policies (GOVCOPP) of the University of Aveiro.

The EEIC 2016 scientific committee received 90 papers for the reviewing process, from which 73 were accepted for oral presentation in 18 parallel scientific sessions at the conference. Moreover, six work in progress presentations were made in two workshops. The parallel scientific sessions and the workshops covered a wide variety of topics in energy economics, including energy and climate policies, carbon markets, modeling simulation and forecasting, regulation and competition laws.

Besides the parallel scientific sessions and the workshops, the EEIC 2016 hosted three presentations from outstanding keynote speakers. In the first day of the conference, Pierre Dechamps from the European Commission talked about “Credible and Feasible decarbonisation pathways towards 2050”. In the second day, the keynote presentations were carried out by Reinhard Madlener from RWTH Aachen University, which presented “High shares of renewable energy sources and needs for electricity market reform”, and by Karen Turner from the University of Strathclyde with a presentation on “Beyond direct rebound: too complex a story for a single measure”. The EEIC 2016 also hosted a roundtable where representatives of the major Iberian utilities presented their viewpoints regarding recent developments, in particular oil price evolution, the Paris agreement and the EU energy union, and their impact upon the Iberian energy market.

The EEIC 2016 was a premier forum for the exchange of ideas and to discuss the development of the energy markets in the Iberian Peninsula, in Europe and throughout the world. The EEIC 2016 strengthened ties among the 155 participants, from 17 countries, of the academia, industry, regulators, competition authorities and policy makers.

For the success of the EEIC 2016 have also contributed our sponsors: EDP, REN, Siemens and GALP Energia.

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An economic analysis of Commercial Aggregator services

Lucía Igualada[1], Cristina Corchero[1], Ioannis T. Moschos[1], Grigorios Kotsis[1], Miguel Cruz-Zambrano[1]

[1] *Catalonia Institute for Energy Research, Jardins de les Dones de Negre, 1, 2ª, Barcelona, Spain,*
ligualada@irec.cat, ccorchero@irec.cat, imoschos@irec.cat, greg-wl@hotmail.com,
miguelcruzzambrano@gmail.com

ABSTRACT

Nowadays, the trends point to a more decentralized electricity sector with a higher penetration rate of renewable generation and more flexible. A key to reach these aims is a service of flexibility products that exploits the flexibility potential of smaller customers connected to distribution networks. This fact implies the requirement of the services of a new agent called Commercial Aggregator (CA). In order to analyse economic effects that the CA services would have over its clients, a methodology with different layers is proposed. This methodology contains five key modules: (1) Scenario Generator and Consumption Forecasting; (2) Consumer Segmentation (Clustering); (3) Flexibility Forecast Tool; (4) Market Forecasting and (5) Commercial Optimal Planning Tool. The proposed methodology has been analysed for two different scenarios: the first one based on current data (2015) and the second one considering a possible future scenario (2020). Both scenarios have the same general inputs and they are based on European low voltage (LV) network for domestic users. Numerical results indicate that higher penetration of RES and flexible loads lead to higher profits for the CA.

KEYWORDS: Commercial Aggregator, Energy Market, Microgrids, Flexibility services, Energy management

1 INTRODUCTION

European Energy Policy aims at promoting the integration of large amounts of renewable energy sources (RES) in the electricity sector. This growing share of variable generation in Europe is increasing the need for flexibility in the electricity system. Stochastic nature of the RES generation hinders system forecasting and scheduling procedures required for a normal and reliable operation. The move towards a liberalized electricity market with high penetration of RES requires an upgrade in the traditional architecture of the power system, including new approaches for system management and new players.

In this context, flexibility management offers the opportunity to exploit the flexibility potential of smaller customers connected to distribution networks, such as household load, distributed generation, and energy storage, becoming a potential revenue source for them through incentives, and allowing Distribution System Operators (DSOs) to have a higher controllability of its networks. In accordance to [1]-[2] flexibility can be defined on an individual level as the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system. Within this paper, flexibility is considered to be provided by aggregated smaller sources, such as household load, distributed generation, and energy storage. As a general term, these grid users will be named as “prosumers” hereinafter, covering both “only-demand” consumers, and those consumers capable of producing their own energy.This fact implies the requirement of the services of a Commercial Aggregator (CA) whose main role will be to gather flexibility products from its prosumers portfolio and to optimize its trading in electricity markets aiming to maximize its profits. This new agent would provide direct revenue to the businesses and homeowners, besides ensuring higher stability and efficiency in the grid.

The main objective of our work is the analysis of economic effects and potential benefits derived from flexibility participation on wholesale markets and specific ancillary services. For doing so, we define a tool which combines optimal management modules for day ahead operation and intraday adjustment for the CA, with a distribution network generator [3]-[4] for offering a set of different random scenarios in order to analyse the CA with a global perspective.

2 FRAMEWORK

2.1 Commercial Aggregator Concept

Potential services to be provided by means of flexibility products within the power system are traded in electricity markets. Given that most consumers and prosumers do not have neither the means nor the size to trade directly into wholesale electricity markets, they require the services of the CA to access them [5].

The Commercial Aggregator concept considered within this paper is following the architecture proposed in ADDRESS FP7 Project where the Aggregator is a central concept. He is the key mediator between the consumers on one side and the markets and the other electricity system participants on the other side. The Aggregators gather the flexibilities and the contributions provided by the former to build Active-Demand-based products relevant and interesting for the latter. “Flexibilities” and contributions of consumers are provided in the form of modifications of their consumption: an Aggregator sells a deviation from the forecasted level of demand, and not a specific level of demand [6].

1.2 Scenarios

In this paper two different scenarios are analysed: the first one based on current data (2015) and the second one considering a possible future scenario (2020). Both scenarios have the same general inputs, such as geographical characteristics of the distribution network as well as the number of nodes and substations in the network. These values have been calculated taking into account European LV network for domestic users.

The differences between two scenarios lie in penetration rates values for renewable generation units, electric vehicles and flexible load profiles. Scenario 2015 takes conservatives values based on a distribution network of Cuellar and mobility values of Barcelona (Spain), while for Scenario 2020 more optimistic values have been considered.

3 METHODOLOGY

Fig. 1 describes a methodology with 5 key modules in order to analyse economic effects that the CA services would have over its clients. The main objective of this methodology is to offer a set of different random scenarios in order to analyse the CA with a global perspective.

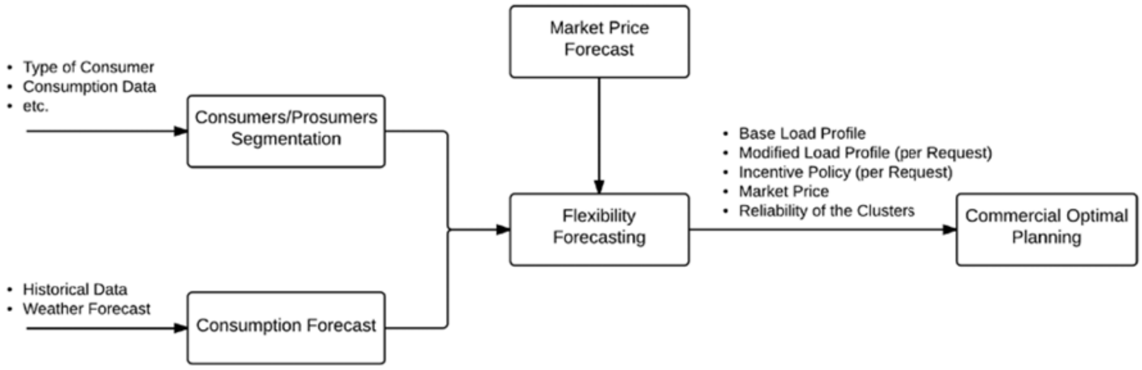

Figure 1:

3.1 Scenario Generation and Consumption Forecasting

The Scenario Generation module generates distribution network topologies whose nodes are located according to a fractal method [3]-[4]. Once the network has been built, the module configures every node. Each node has the opportunity to have a solar panel, a micro wind turbine, an Electric Vehicle (EV) and flexible load profiles depending on random distribution whose parameters are input data of the module. The idea is to send this network of consumers to the next module. However, this first step can be avoided if there is a predetermined set of consumers. Fig. 2 shows this fact by a dashed line.

Consumption Forecasting module is used to forecast the consumption of the prosumers. This information will rely on historical consumption data as well as demand models based on weather information. Consumption forecast will be used for estimating the consumption baseline that will be used afterwards for flexibility services quantification. Baselines should balance accuracy, simplicity and integrity. They should be designed to produce statistically valid and consistent results, unbiased in either over-predicting or underpredicting actual performance. A baseline is important to calculate the effective service provided by the aggregation service provider and to avoid strategic users from being incentivized to emphasize their individual benefits without real gain for the system [2].

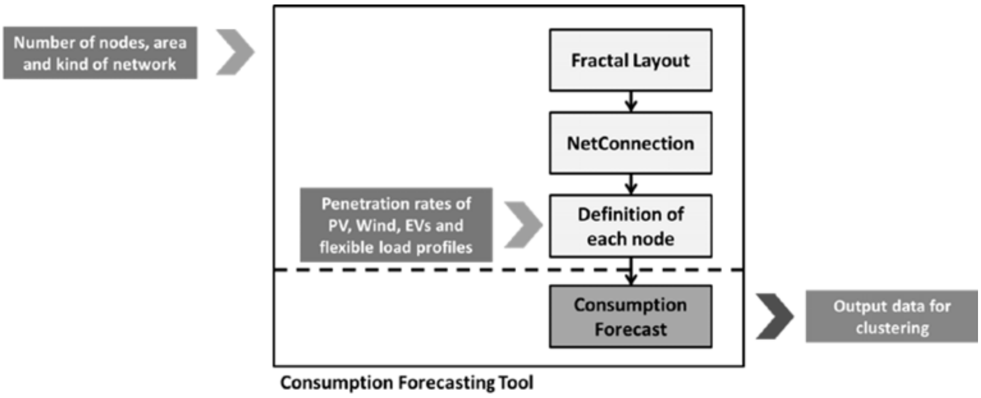

Figure 2: Scenario Generation and Consumption Forecasting Tool

3.2 Consumers Segmentation

The objective of this function is to classify prosumers belonging CA's portfolio into several groups, defined as clusters. Every cluster comprises a group of prosumers sharing some key characteristics for flexibility provision such as a similar consumption pattern, kind of contract, kind of appliances included, or existence (or not) of Energy Storage Systems (ESS), where is included the batteries of the EVs. The clusters are a commercial segmentation, and are used by the CA in order to better handle its portfolio of prosumers and to simplify the calculations. Since every cluster consists of prosumers having a similar behaviour, an average one per cluster may be assumed. Then, incentive policies and their results may be simplified by simulating the average consumer of every cluster.

Fig. 3 shows the 5 clusters considered in this work. Note that the nodes classified as "Consumers" are not client of the CA because they do not have any manageable element.

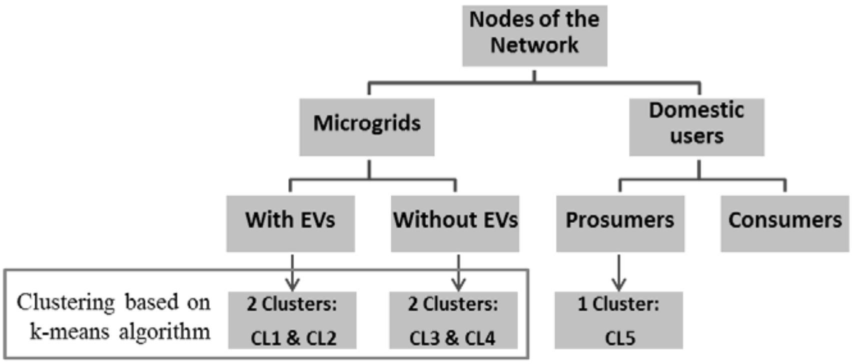

Figure 3: Clustering method for the node in the network

3.3 Flexibility Forecaster Tool

The objective of Flexibility Forecaster module is to predict prosumers' flexibility, under a specific price incentive signal that is sent by the CA to their Energy Management System (EMS). As described in [8] (D6.1 Part II section 4), each prosumer is assumed to have a local EMS which is supposed to minimize its energy costs. The idea is to model a generic EMS optimization algorithm [9] as seen from the Aggregator's perspective [7].

Therefore, the purpose of the Aggregator is to apply price incentive signals to the prosumers according to their energy consumption (purchased power from the grid); the price incentives are linked to pre-defined energy consumption levels. Evidently, there is a correlation between incentive, consumption level and time step. Combining these three factors many possibilities can arise, i.e. different policies would be created. Each combination is referred as a request. For each time step during a request time interval, the EMS algorithm can choose between any combinations.

Every cluster is represented by an average prosumer. The EMS is simulated independently for each cluster and the results are then multiplied by the number of prosumers in the cluster. Thus, the Aggregator forecasts the available flexibility and can later build their portfolio.

3.4 Market Forecasting

This function forecasts the market price of the sold and purchased electricity. These methodologies rely on statistical and financial analyses of the markets where CAs participate.

3.5 The Commercial Optimal Planning Tool

Given the flexibility forecast, as well as the market price forecast, the Commercial Aggregator can schedule the optimal bidding policy, by using the Commercial Optimal Planning Tool. This tool is in fact one optimization algorithm aiming at maximizing the profits of the Commercial Aggregator, subject to some constraints [8]. The profit maximization is achieved in two ways: by selling the available flexibility and by moving the consumption towards the low price hours, in order to procure cheaper energy. During this procedure, the Commercial Aggregator evaluates the set of incentive polices coming from the Flexibility Forecast algorithm and finally picks the most profitable ones, in order to plan its bids. The bids are formed as energy to be sold in the wholesale market. This energy corresponds to the surplus caused by the re-profiling of the consumption.

4 RESULTS

Table 1 shows the characteristics considered for 2015 and 2020 scenarios. Scenario 2015 takes conservatives values based on a distribution network of Cuellar and mobility values of Barcelona and Scenario 2020 more optimistic values expected for 2020 have been considered.

Table 1: Penetration rates

Input Rates	Scenario 2015	Scenario 2020
Domestic Users	100%	100%
Solar Generation	1.38%	20%
Wind Generation	1%	5%
Electric Vehicles	4%	15%
Flexible Load	40%	70%

Results of the clustering process for both scenarios are described in Table 2. For both cases, prosumers connected to the distribution network are clustered as a function of their characteristics. Results shown in the tables are average values for solar, wind and contracted power. Electric vehicle availability is characterized by yes/no. It can be seen how the amount of prosumers increases when Scenario 2020 is compared to Scenario 2015. While for Scenario 2015 only 19 prosumers including controllable loads are obtained, for Scenario 2020 this figure is increased to 34. Average values for PV and wind generation capacity is also increased, while contracted power remains practically unchanged. As a result, higher flexibility is significantly increased when Scenario 2020 is compared to Scenario 2015.

Table 2: Results of the clustering procedure for an average consumer

Average Consumer	Cl. 1	Cl. 2	Cl. 3	Cl. 4	Cl. 5	Cl. 1	Cl. 2	Cl. 3	Cl. 4	Cl. 5
Number of Prosumers	**1**	**1**	**2**	**2**	**13**	**4**	**2**	**8**	**11**	**9**
Solar [kW]	0	0	**1,32**	**0,5**	0	**1,73**	**2,64**	**1,94**	**1,55**	0
Wind [kW]	0	0	0	**1,01**	0	**0,5**	0	**0,44**	**0,55**	0
Contracted Power [kW]	**3,45**	**5,75**	**8,05**	**4,6**	**5,75**	**8,05**	**3,45**	**4,6**	**8,05**	**5,75**
EV	**Yes**	**Yes**	No	No	No	**Yes**	**Yes**	No	No	No

4.1 **CA Results Comparison**

Once incentives to be conveyed to available prosumers are selected by the CA, results obtained for both scenarios are compared.

First, an example of load re-profiling is shown for cluster 2.1 (Scenario 2020 – Cluster 1, Fig. 6).

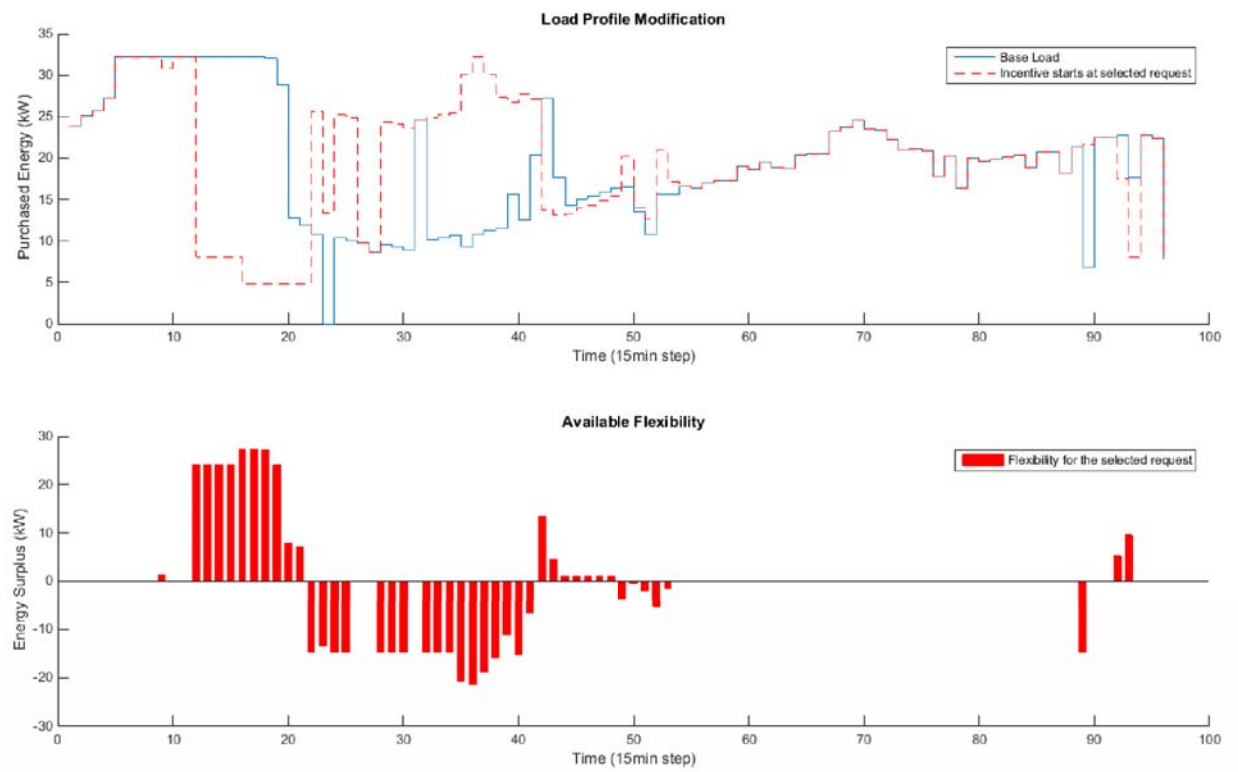

Figure 6: Load re-profiling for Cluster 2.1

The blue line represents the base load (without incentives) and red-dashed line represents the re-profiled load once the incentive is activated. It can be seen how the amount of purchased energy from the grid dramatically decreases while the price incentive (0,17€) is activated from time step #10 to time step #21. A rebound effect therefore appears once the price incentive is removed, especially from time step 22 to time step 42. Small load changes are also found during the rest of the day as a consequence of the load re-profiling process.
Total load-reprofiling for cluster 2.1 is increased from 6,51 kWh to 64,19 kWh, thus increasing the amount of flexibility to be used by the CA for portfolio optimization purposes. Similar results are obtained for the rest of clusters when base load and load re-profiling are compared. This information will be used as an input for the commercial aggregator and network operators for obtaining market results and performing grid validations respectively.

In Fig. 7, total flexibility offered from each cluster is shown for scenarios 2015 and 2020. It can be seen how similarly to cluster 1, a higher amount of flexibility is offered from the rest of clusters. That is not the case for cluster 5, where total amount of flexibility is reduced in accordance with the lower number of prosumers belonging to this cluster. Specifically, flexibility is reduced from 25,48 kWh to 16,98 kWh. However, this reduction is counterweighted by the increase found in the rest of clusters, bringing up total flexibility from 53,69 kWh to 136,52 kWh, i.e. 154% higher.

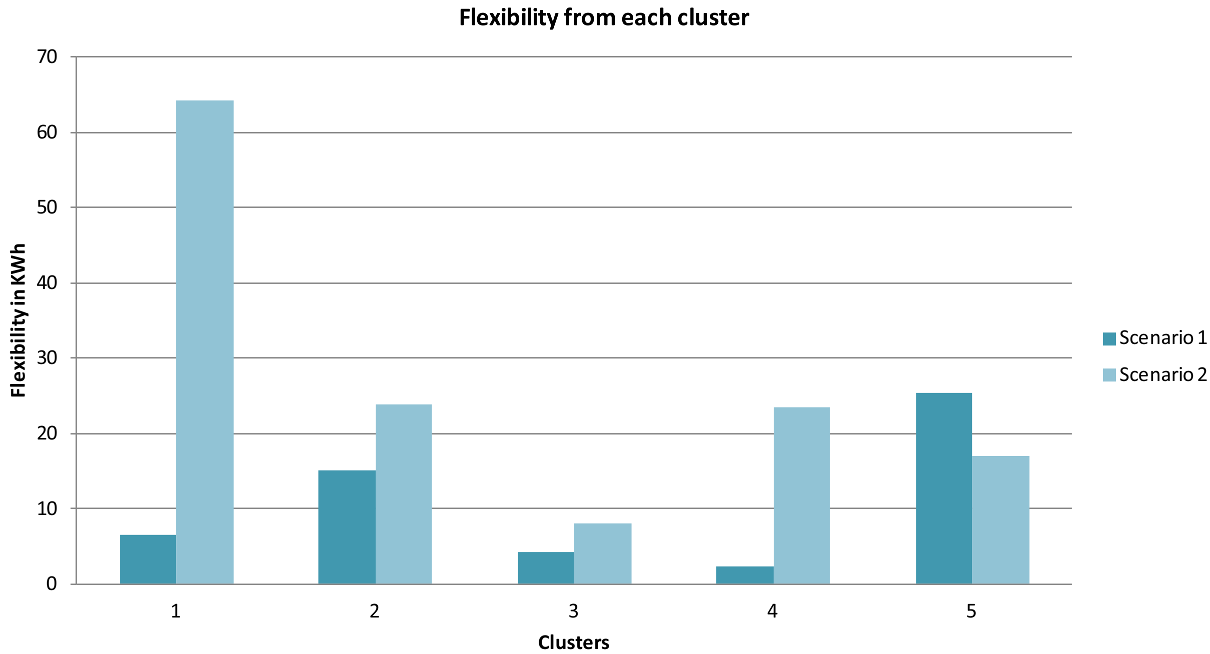

Figure 5: Flexibility offered from each cluster for scenarios 1 and 2

Finally, daily profits and savings for CA and prosumers respectively are shown in Fig. 8.
From the CA perspective, it can be seen how potential profits are increased from Scenario 2015 to Scenario 2020. While total daily profit for Scenario 2015 was 17,98 €, the figure is increased until 39.06 € for Scenario 2020. Therefore, total profit increases with the amount of flexibility obtained from prosumers. However, it should be noticed that flexibility coming from different

clusters show different profitability: while total increase in flexibility offered by cluster 4 is lower than the one offered from cluster 1, total profits obtained from the CA are higher.
Another effect that can be observed is the following: average profit per prosumer increases a 21,40 % from Scenario 2015 to Scenario 2020. While for Scenario 2015 average profits are 0,94 €/user, it were 1,15 €/user for Scenario 2020. From this, it can be concluded that higher penetration of RES and flexible loads lead to higher profits for CAs.
From the prosumers perspective, it can be seen how for all cases bill savings account for more than 10 %. Reason behind is that a savings threshold has been set for the CA when selecting the incentives to be activated. When scenarios 2015 and 2020 are compared, no major changes are observed excepting for cluster 2, where the higher amount of RES availability give more room to EV owners to shift their consumption, thus increasing the flexibility potential to be offered.

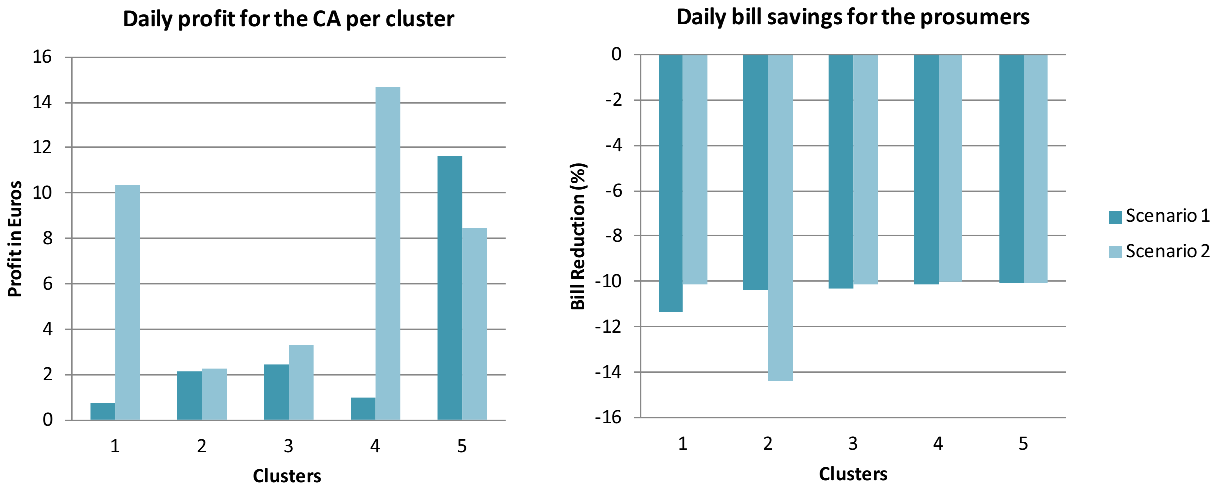

Figure 6: CA daily profit and daily savings from prosumers

5 CONCLUSIONS

In this paper, we have presented a methodology composed by 5 modules with the goals of generating different sets of scenarios with similar characteristics to actual consumer networks in order to simulate the main processes of a CA. The final aim is to analyze the economic effects that the CA services would have over its clients and itself. Specifically, the 5 key modules are: (1) Scenario Generator and Consumption Forecasting; (2) Consumer Segmentation (Clustering); (3) Flexibility Forecast Tool; (4) Market Forecasting and (5) Commercial Optimal Planning Tool. The proposed methodology has been analysed in two different scenarios based on a European LV network for domestic user; Scenario 2015 with conservatives values and Scenario 2020 with more optimistic values, yielding the following results:

- From the prosumers perspective: numerical results from our study show how for all cases bill savings account for more than 10%. A main reason for this fact is the growth of the clusters that include a storage or/and generation units, whose flexibility potential to be offer is higher.
- From the CA perspective: results show how potential profits are increased from Scenario 2015 to 2020. Specifically, average profit per prosumer increases a 21,40 % in the second scenario, while the daily profit is doubled from 2015 to 2020. From these results, it can be concluded that higher penetration of RES and flexible loads lead to higher profits for CAs

- The results indicate that higher penetration of RES and flexible loads lead to higher profits.

Taking into account the above, it is clear that the Commercial Aggregator is a key gateway between the power system and the small consumers to face future challenges posed by growing demand and RES integration.

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An empirical analysis of the relationships between crude oil, gold and stock markets

Semei Coronado[a], Rebeca Jiménez-Rodríguez[b], Omar Rojas[c]

[a]*Department of Quantitative Methods, Universidad de Guadalajara, Guadalajara, Mexico*
[b]*Department of Economics, IME, University of Salamanca, Salamanca, Spain*
[c]*School of Business and Economics, Universidad Panamericana, Guadalajara, Mexico*

Abstract

This paper analyzes the direction of the causality between crude oil, gold and stock markets for the largest economy in the world with respect to such markets, the US. To do so, we apply non-linear Granger causality tests. We find a nonlinear causal relationship among the three markets considered, with the causality going in all directions, when the full sample and different subsamples are considered. However, we find a unidirectional nonlinear causal relationship between the crude oil and gold market (with the causality only going from oil price changes to gold price changes) when the subsample runs from the first date of any year between the mid-1990s and 2001 to last available data (February 5, 2015). The latter result may explain the lack of consensus existing in the literature about the direction of the causal link between the crude oil and gold markets.

Keywords: Nonlinear Granger-causality test, Oil price, Gold price, Stock markets

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1. Introduction

The crude oil and gold markets are the main representative of the large commodity markets and seem to drive the price of other commodities (see Sari et al., 2010). On the one hand, gold is the leader in the precious metal markets and is considered as an investment asset. Gold is a safe haven to avoid an increase in financial risk (see Aggarwal and Lucey, 2007), a

Email addresses: semeic@cucea.udg.mx (Semei Coronado), rebeca.jimenez@usal.es (Rebeca Jiménez-Rodríguez), orojas@up.edu.mx (Omar Rojas)

store of value (see Baur and Lucey, 2010) and a hedge against inflation (see Jaffe, 1989); consequently it is used as a fundamental investment strategy (see Baur and McDermott, 2010). On the other hand, crude oil is the main source of energy and is also used as an investment asset. Therefore, investors often include one of the two commodities –gold and crude oil– or both in their investment portfolios as a diversification strategy (see Soytas et al., 2009).

There seems to be a close relationship between the price movements of the two commodity markets, but there is no consensus on the direction of the influence. Baffes (2007), Zhang and Wei (2010) and Sari et al. (2010) found that gold prices respond significantly to changes in oil prices. However, there are some authors such as Narayan et al. (2010) and Wang and Chueh (2013) that argue that oil and gold prices affect each other.[1] Reboredo (2013) pointed out the four mechanisms through which crude oil and gold (seen as an investment asset) are linked: a) the increase in oil prices leads to inflationary pressures (see, e.g. Hooker, 2002; Chen, 2009; Álvarez et al., 2011) that induces gold prices to increase since gold is seen as a hedge against inflation; b) high oil prices have a negative impact on economic growth (see Hamilton, 2003; Jiménez-Rodríguez and Sánchez, 2005; Kilian, 2008; Cavalcanti and Jalles, 2013) and asset values (see Reboredo, 2010), which gives rise to an increase in gold price since it is seen as an alternative asset to store value; c) higher oil prices have a positive effect on revenues in net oil exporting countries, which increases their investment in gold to maintain its share in the diversified portfolios and, consequently, gold price increases due to higher gold demand (see Melvin and Sultan, 1990); and d) when the US dollar depreciates oil prices rise (see Reboredo, 2012) and investors may use gold as a safe haven.

Given that oil and gold are used as investment asset,[2] they are closely related to the evolution of stock market indices since any influence on decisions about investment portfolios affects the stock market returns (see Ciner et al., 2013).

The relationship between changes in oil prices and stock market indices has been widely studied. Authors such as Jones and Kaul (1996), Sadorsky (1999), Ciner (2001), Park and Ratti (2008), Kilian and Park (2009), Ciner

[1] Bampinas and Panagiotidis (2015) found a unidirectional causality from oil prices to gold prices before the 2007/2008 crisis and a biderectional causality after the crisis.

[2] As was pointed out, gold and oil are often used as a safe haven against the more traditional asset classes such as equities and bonds.

(2013) and Jiménez-Rodríguez (2015) found that an oil price increase has a negative impact on stock returns in oil importing countries,[3] while Bjørnland (2009) and Wang et al. (2013) found a positive impact of oil price increases on the stock market in oil exporting countries. However, there are fewer authors who have analyzed how gold prices affect stock market indices, and vice versa. Smith (2001)[4,5] studied the relationship between gold prices and the US stock price indices over the 1991-2001 period. He considered four gold prices (three set in London: 10.30 a.m. fixing, 3 p.m. fixing, and closing time; and one set in New York: Handy & Harmon) and six stock price indices (the Dow Jones Industrial Average, NASDAQ, the New York Stock Exchange, Standard and Poor's 500, Russell 3000, and Wilshire 5000) and showed evidence of a short-run relationship, but not a long-run link. He also found evidence of feedback between gold price set in the afternoon fixing and US stock price indices by using linear Granger causality test, but unidirectional causality from US stock price indices to gold price set in the morning fixing and closing time. Bhunia and Das (2012) analyzed the causal link between gold prices and Indian stock market returns, showing the bidirectional Granger-causality.

The study of the link between the two commodity markets (crude oil and gold) and the stock market indices is of interest to policymakers since the movements in the stock market has an important influence on macroeconomic variables development. To the best of our knowledge, there is no study in the related literature that analyzes the relationships between crude oil, gold and stock markets for the largest economy in the world, the US.[6]

The contribution of this paper is to extend the literature on the relationships between the crude oil and gold markets and the Standards and Poor's

[3] It is worth noting that there are some authors that did not find any significant impact of oil price changes on stock markets (see Huang et al., 1996; Apergis and Miller, 2009).

[4] Authors such as Sherman (1982), Herbst (1983) and Jaffe (1989) had previously studied the role of gold in investment portfolio.

[5] There are authors who state the relative benefits of including gold in the investment portfolios (see Sherman, 1982; Hillier et al., 2006; Baur and Lucey, 2010). Sherman (1982) indicated that gold has less volatility than stocks and bonds and improves overall portfolio performance. Hillier *et al.* (2006) found that portfolios that include precious metals outperform those with standard equity portfolios. Baur and Lucey (2010) showed that gold can be considered as a hedge against stocks on average and a safe haven in extreme stock market conditions.

[6] See the last Gross Domestic Product ranking table based on Purchasing Power Parity provided by the World Bank for 2013 (http://data.worldbank.org/data-catalog/GDP-ranking-table).

500 index by analyzing the direction of the causality and by considering data from the Great Moderation onwards. To do so, we apply the nonlinear Granger causality test for the full sample and for different subsamples in order to analyze the sensitivity of the results to the use of different sample periods. Additionally, we perform the nonlinear Granger causality test for windows of one natural year from 1986 up to 2014 to investigate the causal link within each specific year.

The paper is structured as follows. Section 2 describes the data and the methodology. Section 3 presents the results and discussion. Section 4 concludes.

2. Data and methodology

The empirical sample used for the present study consists of Standard and Poor's 500 daily adjusted closing price (SP500), West Texas Intermediate crude oil spot price (WTI) and Gold Bullion LBM US/Troy Ounce (Gold) from January 2nd, 1986 to February 5th, 2015, with a total of 7351 observations. All data are available from *Bloomberg*. These dates were chosen in order to capture different economic moments in the relationships between the series.

Prices were transformed into series of continuously compounded percentage returns by taking the first differences of the natural logarithm of the prices, i.e. $r_t = 100(\ln(p_t) - \ln(p_{t-1}))$, where p_t is the price on day t. We denote the return time series for SP500, WTI and Gold by SP500R, WTIR and GoldR, respectively. Figure 1 shows the behavior of the prices and returns for each series.

Table 1 presents the descriptive statistics of the return time series. The statistics are consistent, as expected, with some of the stylized facts of financial and economic time series (see Cont, 2001). In particular, the kurtosis indicates that return distributions are leptokurtic. Moreover, the Jarque and Bera (1987) statistic confirms returns are not normally distributed.

We first analyze the stationarity of the variables considered[7] by applying the Augmented Dickey and Fuller (1981) test and the Residual Augmented Least Squares (RALS) test proposed by Im et al. (2014), which does not require either knowledge of a specific density function of the error term or knowledge of functional forms.

[7] It is worth noting that the causality tests are only valid if the variables have the same order of integration (see, e.g. Papapetrou, 2001)

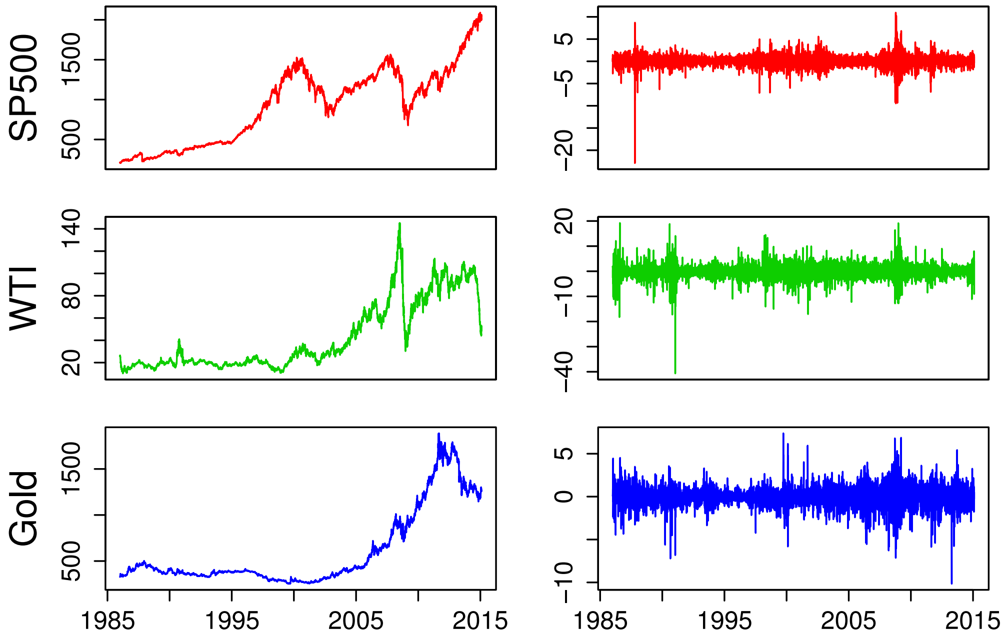

Figure 1: Time series plots of prices, p_t, (left) and returns, r_t, (right) for SP500 (top), WTI (middle) and Gold (bottom).

Table 1: Descriptive statistics of the return time series

Statistic	SP500R	WTIR	GoldR
Mean	0.03	0.01	0.02
Min	−22.90	−40.69	−10.16
Max	10.96	19.24	7.38
Sd	1.17	2.52	1.00
Skewness	−1.28	−0.72	−0.39
Kurtosis	30.90	18.24	10.52
Jarque-Bera	240345.68	71751.11	17491.18

In addition to stationarity, it is standard to test for linearity of the asset variables. Thus, we apply the BDS test (Brock et al., 1996) and the Tsay (1986) test to our variables. Whereas the Tsay test is a direct test for non-linearity of a specific time series, the BDS test is an indirect test.

The aim of the Tsay (1986) test is to detect quadratic serial dependence in the data (see Tsay, 1986, for further details). The BDS test was originally developed to test for the null hypothesis of independent and identical distribution (*iid*) in order to detect non-random chaotic dynamics, but when it is applied to the residuals from a fitted univariate linear time series model the test uncovers any remaining dependence and the presence of an omitted nonlinear structure. Consequently, if the null hypothesis cannot be rejected, then the fitted univariate linear model cannot be rejected. However, if the null hypothesis is rejected, the fitted univariate linear model is misspecified, and in this sense, it can also be treated as a test for nonlinearity (see Zivot and Wang, 2006). There are two main advantages of choosing the BDS test: (1) it has been shown to have more power than other linear and nonlinear tests (see Brock et al., 1991; Barnett et al., 1997); and (2) it is nuisance-parameter-free and does not require any adjustment when applied to fitted model residuals (see F de Lima, 1996). See Brock et al. (1996) for further details.

We analyze the Granger causality relationship among the variables considered. Notice that for a strictly stationary bivariate process $\{X_t, Y_t\}$ the process $\{Y_t\}$ is Granger caused by $\{X_t\}$ if the past and current values of $\{X_t\}$ contain additional information of future values of $\{Y_t\}$ that is not contained in past and current values of $\{Y_t\}$ alone.[8] Recently, there has been an increase of interest in nonparametric versions of the Granger non-causality hypothesis against linear and nonlinear Granger causality (see Hiemstra and Jones, 1994; Bell et al., 1996; Su and White, 2008). Given that the linear Granger causality test might fail to uncover nonlinear causal relationships, we use the Diks and Panchenko (2006) nonlinear Granger causality test (hereafter, DP test).

The DP test is a nonparametric Granger causality test based on the use of the correlation integral between time series and based on Baek and Brock (1992) but without the assumption of the time series being mutually and individually independent and identically distributed. It has has also been shown to be more display short-term temporal dependence, since it reduces the over-rejection whenever the null hypothesis is true.

We next describe the DP test closely following the description offered by Diks and Panchenko (2006). It is denoted by $X_t^{l_X} = (X_{t-l_X+1}, ..., X_t)$ and $Y_t^{l_Y} = (Y_{t-l_Y+1}, ..., Y_t)$ the delay vector of X_t and Y_t, respectively. The null hypothesis tested is the lack of causality, that is, that past observations of X_t do not contain additional information about Y_{t+1}:

$$H_0 : Y_{t+1}|(X_t^{l_X}; Y_t^{l_Y}) \sim Y_{t+1}|Y_t^{l_Y} \tag{1}$$

[8]See Granger (2001), Diks and Panchenko (2006) and Wolski (2014) for a formal definition of Granger causality.

Considering a strictly stationary bivariate time series $\{X_t, Y_t\}$, the null hypothesis is a statement about the invariant distribution of the $(l_X + l_Y + 1)-$dimensional vector $W_t = (X_t^{l_X}, Y_t^{l_Y}, Z_t)$, with $Z_t = Y_{t+1}$. Assuming that the null hypothesis is a statement about the invariant distribution of W_t, the time subscript can be dropped and it can be just written as $W = (X, Y, Z)$. To simplify the test description, it is assumed that $l_X = l_Y = 1$. Thus, the conditional distribution of Z given $(X, Y) = (x, y)$ is the same, under the null hypothesis, as that of Z given $Y = y$. In terms of joint probability density function, $f_{X,Y,Z}(x, y, z)$, and its marginals, the null hypothesis has to ensure:

$$\frac{f_{X,Y,Z}(x,y,z)}{f_Y(y)} = \frac{f_{X,Y}(x,y)}{f_Y(y)} \cdot \frac{f_{Y,Z}(y,z)}{f_Y(y)} \tag{2}$$

for each vector (x, y, z) in the support of W. Thus, it can be stated that X and Z are independent conditionally on $Y = y$ for each value of y (see Bekiros and Diks, 2008; Wolski, 2014). Diks and Panchenko (2006) show that the reformulated null hypothesis implies the q statistic to be noted as

$$q \equiv E\left[f_{X,Y,Z}(X,Y,Z)f_Y(Y) - f_{X,Y}(X,Y)f_{Y,Z}(Y,Z)\right], \tag{3}$$

where the proposed estimator for q is:

$$T_n(\epsilon_n) = \frac{(2\epsilon_n)^{-d_X-2d_Y-d_Z}}{n(n-1)(n-2)} \sum_i \left[\sum_{k,k\neq i} \sum_{j,j\neq i} \left(I_{ik}^{XYZ} I_{ij}^{Y} - I_{ik}^{XY} I_{ij}^{YZ}\right)\right], \tag{4}$$

where $I_{ij}^U = I(\|U_i - U_j\| < \epsilon_n)$, with $I(\cdot)$ being an indicator function, $\|\cdot\|$ being the maximum norm and ϵ_n being the bandwidth which depends on the sample size. Denoting $\hat{f}_U(U_i)$ as the local density estimator of the vector U at U_i ,i.e.,

$$\hat{f}_U(U_i) = (2\epsilon_n)^{-d_U} (n-1)^{-1} \sum_{j,j\neq i} I_{ij}^U, \tag{5}$$

the test statistic simplifies to

$$T_n(\epsilon_n) = \frac{n-1}{n(n-2)} \sum_i \left(\hat{f}_{X,Y,Z}(X_i,Y_i,Z_i)\hat{f}_Y(Y_i) - \hat{f}_{X,Y}(X_i,Y_i)\hat{f}_{Y,Z}(Y_i,Z_i)\right). \tag{6}$$

Considering one lag (which implies that $d_X = d_Y = d_Z = 1$), for a sequence with bandwidth $\epsilon_n = Cn^{-\beta}$, where $C > 0$ and $1/4 < \beta < 1/3$, the test statistic satisfies

$$\sqrt{n}\left(\frac{T_n(\epsilon_n) - q}{S_n}\right) \xrightarrow{D} N(0,1) \tag{7}$$

where S_n is an estimator of the asymptotic standard error of $T_n(\cdot)$ and $\xrightarrow{D}$ denotes convergence in distribution. We implement a one-tailed version of the test, rejecting the null hypothesis if the left hand side of the equation (7) is too large. See Diks and Panchenko (2006) for further details.

3. Empirical Results

Table 2: Unit-root tests results

Series	SP500	WTI	Gold
Series in levels			
With trend and intercept			
ADF	-1.51	-2.59	-1.43
RALS	-1.71	-0.46	-1.06
With drift			
ADF	0.07	-1.58	-0.22
RALS	1.32	1.74	-0.15
Series in first differences	SP500R	WTIR	GoldR
With trend and intercept			
ADF	-21.36^{***}	-33.77^{***}	-25.85^{***}
RALS	-22.66^{***}	-33.50^{***}	-29.09^{***}
With drift			
ADF	-21.34^{***}	-33.77^{***}	-25.85^{***}
RALS	-22.67^{***}	-33.50^{***}	-29.02^{***}

Notes: The null hypothesis is that there is a unit root. The lag was selected by using Bayesian Information Criteria. One/two/three asterisks mean a p-value less than 10%, 5% and 1%, respectively.

Table 2 shows the results of the ADF and the RALS. Both tests fail to reject the null hypothesis that the series in levels are non-stationary and reject the null hypothesis that the series in first differences are non-stationary at the 5% critical level. Thus, the series in levels are integrated of order one, $I(1)$.

We perform the BDS test on the residuals of the return time series for dimensions up to 4 and values of ϵ equal to $0.5\sigma_x$, σ_x, $1.5\sigma_x$, where σ_x represents the standard deviation of the return time series x_t. The results of the tests show the rejection of the null hypothesis in all cases (see Table 3), from which the nonlinearity of the series can be inferred.

Table 4 shows the results of the Tsay (1986) test, showing that we reject the null hypothesis of linearity and confirming results found with the BDS

Table 3: BDS nonlinearity test results

Series	m/ϵ	0.5σ	σ	1.5σ	2σ
	2	12.44***	14.24***	16.58***	19.46***
SP500R	3	19.14***	21.24***	23.27***	25.50***
	4	24.42***	25.97***	27.18***	28.73***
	2	14.57***	17.10***	18.96***	19.32***
WTIR	3	19.90***	22.29***	24.47***	24.99***
	4	25.08***	26.20***	27.72***	28.01***
	2	11.21***	10.24***	10.55***	11.34***
GoldR	3	16.79***	14.43***	14.21***	14.51***
	4	22.45***	18.18***	17.39***	17.14***

Notes: The null hypothesis is that the residuals are iid. One/two/three asterisks mean a p-value less than 10%, 5% and 1%, respectively.

Table 4: Tsay nonlinearity test results

Lag	SP500R	WTIR	GoldR
1	23.81***	16.63***	1.11
2	12.03***	12.12***	1.74
3	10.16***	13.66***	2.60**
4	11.08***	10.29***	2.21**
5	10.11***	8.13***	1.91**
6	8.49***	7.36***	2.00***
7	7.49***	7.29***	2.27***

Note: The null is that the series are linear. One/two/three asterisks mean a p-value less than 10%, 5% and 1%, respectively.

test. Therefore, there seems to be a nonlinear univariate structure behind all our time series. This information is considered and we use the nonlinear Granger-causality test proposed by Diks and Panchenko (2006).

We apply the DP test to the delinearized series. The series have been delinearized by using a VAR filter, whose lag length is chosen on the basis of Bayesian Information Criterion. As Hiemstra and Jones (1994) and Bampinas and Panagiotidis (2015) state "*by removing linear predictive power with a VAR model, any causal linkage from one residual series of the VAR model to another can be considered as nonlinear predictive power*". We perform the DP test for the full sample and for different subsamples to investigate the sensitivity of such results to the use of different sample periods. Additionally, we apply the DP test for windows of one natural year from 1986 up to 2014 in order to analyse the causal link within each specific year.

Table 5 presents the results of DP test for the full sample (January 2, 1986 - February 5, 2015) in a compact way following the simplifying notation of Bekiros and Diks (2008), who consider one/two/three asterisks to indicate that the corresponding p-value of a test is lower than 10%, 5% and 1%, respectively. Directional causalities will be denoted by the functional representation $\nrightarrow$, *i.e.*, $x \nrightarrow y$ means that the VAR filtered r_x series does not Granger cause the VAR filtered r_y series. $(\cdot,\cdot,\cdot)$ denotes the value of p for the $VAR(p)$ filter of the series $\{x, y\}$, $\{x, z\}$ and $\{y, z\}$. Finally, x represents SP500R, y refers to WTIR and z is GoldR.

Table 5: Nonlinear Granger causality test results for the full sample

Lag	$x \nrightarrow y$	$y \nrightarrow x$	$x \nrightarrow z$	$z \nrightarrow x$	$y \nrightarrow z$	$z \nrightarrow y$
1	$***$	$***$	$***$	$***$	$***$	$***$
2	$***$	$***$	$***$	$***$	$***$	$***$
3	$***$	$***$	$***$	$***$	$**$	$**$
4	$***$	$***$	$***$	$**$	$*$	$**$
5	$***$	$***$	$***$	$*$	$*$	$***$

Note: Note: One/two/three asterisks mean a p-value less than 10%, 5% and 1%, respectively. The null hypothesis is that r_x does not Granger cause r_y (i.e., $x \nrightarrow y$). Denoting SP500R, WTIR and GoldR as x, y and z, respectively.

Table 5 indicates that the three markets considered (the crude oil, gold and stock markets) are interrelated, with the causality going in all directions. The bidirectional causality between the price movements of the two commodity markets is in concordance with Narayan et al. (2010) and Wang and Chueh (2013), showing the mutual influence of the two investment assets since the Great Moderation. Moreover, the bidirectional causality between the Standard and Poor's 500 returns and changes in the price of the two commodities implies that movements in S&P's 500 index may be monitored by observing changes in commodity prices and vice versa. The feedback relationship between the crude oil and stock markets is in line with Ciner (2001), among others. The bidirectional causal relationship between the gold market and the US stock price index is very relevant and has been only found by Smith (2001) for a specific gold price (3 p.m. fixing).

To analyze whether the results obtained depends on the sample period

Table 6: Nonlinear Granger causality test results for rolling windows from 1986 to the ending year

Ending year	ϵ	sample size	$x \nrightarrow y$	$y \nrightarrow x$	$x \nrightarrow z$	$z \nrightarrow x$	$y \nrightarrow z$	$z \nrightarrow y$
1991	1.15	1517	*				*	*
1992	1.05	1773	**	*	*	*	**	*
1993	1.00	2032	**	*	*	*	**	**
1994	0.97	2289	***	*	*	**	**	**
1995	0.96	2541	***	**	*	*	***	***
1996	0.94	2795	***	**	**	*	*	*
1997	0.92	3048	***	**	**	**	*	*
1998	0.90	3300	**	*	*	*	*	**
1999	0.88	3552	***	*	*	**	**	**
2000	0.86	3804	***	*	**	**	*	**
2001	0.84	4053	***	*	**	***	*	*
2002	0.82	4305	***	*	***	**	*	**
2003	0.80	4557	***	*	**	***	**	***
2004	0.78	4809	***	*	**	**	**	***
2005	0.76	5061	***	**	**	**	**	***
2006	0.75	5312	***	*	*	**	**	***
2007	0.74	5563	***	*	*	**	**	**
2008	0.74	5816	***	**	**	**	**	***
2009	0.73	6068	***	**	***	***	**	***
2010	0.73	6320	***	*	***	***	*	*
2011	0.72	6572	***	**	**	**	**	***
2012	0.71	6822	***	*	***	***	*	***
2013	0.70	7074	***	**	***	***	*	***
2014	0.69	7326	***	**	***	***	*	*

Note: One, two and three asterisks mean a p-value less than 10%, 5% and 1%, respectively. The null hypothesis is that r_x does not Granger cause r_y (i.e., $x \nrightarrow y$). Denoting SP500R, WTIR and GoldR as x, y and z, respectively. Even though the DP test is run considering different lags ($l = 1, 2, 3, 4, 5$), it is only reported for each sample the lowest significance level (*,** or ***) for the cases in which causality appears at every lag considered. If no asterisk appears for a particular sample, it means that the causality may exist at some specific lag but not at all possible lags considered.

considered we apply the DP test to different subsamples, with subsamples containing a minimum of five years of observations. Whereas Table 6 presents the results for the subsamples that run from January 2, 1986 to the last available observation of the year indicated under the notation "ending year", Table 7 shows the results for the subsamples that run from the first available observation of the year indicated under the notation "starting year" to February 5, 2015. Both Tables only report for each sample the lowest significance level (*,** or ***) for the cases in which causality appears at every lag considered. If no asterisk appears for a particular sample, it means that the causality may exist at some specific lag but not at all possible lags considered.

Table 7: Nonlinear Granger causality test results for rolling windows from the starting year to 2014

Starting year	ϵ	sample size	$x \nrightarrow y$	$y \nrightarrow x$	$x \nrightarrow z$	$z \nrightarrow x$	$y \nrightarrow z$	$z \nrightarrow y$
1987	0.70	7099	**	*	***	***	**	*
1988	0.71	6846	***	**	***	***	*	***
1989	0.72	6592	***	**	***	***	*	**
1990	0.72	6340	***	**	***	***	*	**
1991	0.73	6086	***	*	***	***	*	*
1992	0.74	5833	***	*	***	***	**	*
1993	0.74	5577	***	**	***	***	***	*
1994	0.75	5318	**	*	***	***	*	*
1995	0.76	5061	**	*	***	***	***	*
1996	0.77	4809	**	**	***	**	*	
1997	0.79	4555	***		***	***	**	
1998	0.82	4302	***	**	***	***		
1999	0.84	4050	***	**	***	***	**	
2000	0.86	3798	**	**	***	***	**	
2001	0.88	3546	***	*	***	***	**	
2002	0.90	3297	**	**	***	**	***	*
2003	0.85	3045	**	**	**	**	*	*
2004	0.97	2793	*	*	***	**	*	*
2005	1.00	2541	**	**	***	**	**	*
2006	0.98	2289	**	*	***	***	*	**
2007	1.00	2038	***	**	***	***	*	*
2008	1.05	1787	*	**	***	***	*	*
2009	1.09	1534	*	*	***	***	*	*

Note: One, two and three asterisks mean a p-value less than 10%, 5% and 1%, respectively. The null hypothesis is that r_x does not Granger cause r_y (i.e., $x \nrightarrow y$). Denoting SP500R, WTIR and GoldR as x, y and z, respectively. Even though the DP test is run considering different lags ($l = 1, 2, 3, 4, 5$), it is only reported for each sample the lowest significance level (*,** or ***) for the cases in which causality appears at every lag considered. If no asterisk appears for a particular sample, it means that the causality may exist at some specific lag but not at all possible lags considered.

Tables 6 and 7 show that we reject the null hypothesis of that S&P's 500 returns do not Granger cause oil price changes at the 1% critical level for most subsamples. We also reject that oil price changes do not Granger cause S&P's 500 returns at a 5% critical level for an important number of subsamples. Thus, the bidirectional causality between the crude oil and stock markets found for the full sample is verified when different subsamples are considered, although the causality from oil price changes to S&P's 500 returns seems to weaken depending on when the sample starts and ends.

Tables 6 and 7 also indicate the rejection of the null hypothesis when the returns of the gold and stock markets are considered, showing so a bidirectional causality for almost all subsamples and confirming the results obtained for the full sample. Additionally, these tables reveal the feedback relationship between the crude oil and gold markets when the sample starts in January 2, 1986 and ends in the last available observation of any year beyon 1991. However, a unilateral Granger causality was found from oil price changes to gold price changes when the sample starts in the first available observation of any year between the mid-1990s and 2001 and ends in February 5, 2015. This may explain why some authors (see, e.g. Zhang and Wei, 2010) find a unilateral causality.

Finally, Table 8 reports the results of the DP test for windows of one natural year from 1986 up to 2014, although these results have to be considered with caution since the DP test is an asymptotic test. Table 8 shows no evidence of a causality within most of the years considered. The main exception to this is for the years 2008 and 2009 (the period of global financial crisis), where the three markets appear interrelated. These causal relationships might be due to the fact that gold is considered a safe haven for investors in times of financial crisis and economic instability and also due to investors seeking refuge on gold and other commodities such as oil and energy derivatives after the collapse of the real state market.

4. Conclusions

This paper provides new evidence on a nonlinear causal link among the three markets considered (with the causality going in all directions) for the full sample, for subsamples starting in January 2, 1986 and ending in the last available observation of any year beyond 1991 and for subsamples starting in the first available observation of any year beyond 1987 and ending in February 5, 2015. The only exception to this is the existence of a nonlinear unidirectional causal relationship between the crude oil and gold market (with the causality only going from oil price changes to gold price changes) for subsamples that going from the first date of any year between the mid-1990s and 2001 to February 5, 2015. Therefore, the causality between the price movements of the crude oil and gold markets seems highly dependent on the sample used, which may explain the contradictory results found in the related literature.

The causal link found among the three markets implies that changes in the S&P's 500 index may be monitored by observing changes in the returns of the two commodity markets considered (and vice versa), which is valuable for policymakers

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Table 8: Nonlinear Granger causality test results by year

years	$x \nrightarrow y$	$y \nrightarrow x$	$x \nrightarrow z$	$z \nrightarrow x$	$y \nrightarrow z$	$z \nrightarrow y$
1986						
1987			*			
1989			*			*
1990	*	**	**		*	
1991		**	*		**	**
1992		*	*			
1993						
1994			*		*	*
1995						*
1996				*		
1997			*			*
1998						
1999					*	
2000	*					
2001						
2002					*	
2003	*		*			*
2004			*		*	**
2005	*				*	
2006			*	*		
2007	*		*			*
2008	***	**	**	*	**	*
2009	**	*	*	*	*	**
2010	*	*				*
2011		*	**	*		
2012	*					
2013		*	*	*		*
2014	**	**			*	

Note: One, two and three asterisks mean a p-value less than 10%, 5% and 1%, respectively. The null hypothesis is that r_x does not Granger cause r_y (i.e., $x \nrightarrow y$). Denoting SP500R, WTIR and GoldR as x, y and z, respectively. Even though the DP test is run considering different lags ($l = 1, 2, 3, 4, 5$), it is only reported for each sample the lowest significance level (*,** or ***) for the cases in which causality appears at every lag considered. If no asterisk appears for a particular sample, it means that the causality may exist at some specific lag but not at all possible lags considered.

Transmission Costs, Transmission Capacities and their Influence on Market Power in Wholesale Electricity Markets*

Mario Blazquez de Paz†

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Abstract

The integration of electricity markets around the world has increased the importance of congestion between countries/states and has initiated a discussion of how to harmonize network tariffs. This paper analyzes how the transmission capacity and the transmission cost, such as a transmission tariff, influence bidding behavior in electricity markets. It is shown that transmission costs can have seemingly counter-intuitive effects. Normally, more transmission capacity would improve competition, but this is not necessarily the case when one considers transmission costs. The paper also illustrates that there are cases where increasing transmission costs could have a pro-competitive effect and benefit consumers. In contrast, point of connection tariffs, which are used in the majority of the European countries, always push up electricity prices and always hurt consumers.

KEYWORDS: electricity auctions, wholesale electricity markets, transmission capacity constraints, network tariffs, energy economics.
JEL codes: D43, D44, L13, L94

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†Research Institute of Industrial Economics. Mail: mario.blazquezdepaz@ifn.se

1 Introduction

The integration of electricity markets around the world has increased the importance of congestion between countries/states and has initiated a discussion of how to harmonize network tariffs. In general, transmission from regions with low prices to regions with high prices benefits social welfare. In deregulated electricity markets, more transmission would, in addition, normally improve the market competitiveness. However, it is very costly to expand transmission capacity. In order to focus investments to points in the grid where the gains in terms of enhanced market performance will be the largest, one needs a better understanding of how transmission capacity influences competition between spatially distributed producers. The contribution of this paper is to characterize the outcome of an electricity market auction and how it depends on transmission constraints and transmission costs.

The analysis employs a simple duopoly model similar to that in Fabra et al. (2006). In the basic set up, the two suppliers have symmetric production capacities and marginal costs, but are located in two different markets ("North" and "South") that are connected through a transmission line with a limited transmission capacity.[1] Each firm faces a perfectly inelastic demand in each market that is known with certainty when suppliers submit their offer prices. Each supplier must submit a single price offer for its entire capacity[2] in a discriminatory price auction such as those used in the UK wholesale electricity market. The assumption of price-inelastic demand can be justified by the fact that the vast majority of consumers purchase electricity under regulated tariffs that are independent of the prices set in the wholesale market, at least in the short run. The assumption that suppliers have perfect information concerning market demand is reasonable when applied to markets where offers are "short lived", such as in Spain, where there are 24 hourly day-ahead markets each day.

Suppliers pay a monetary charge (tariff) to the network owner when using the grid. The charge is linear and it depends on how much power the suppliers inject into the grid (*point of connection tariff*) or transmit through the grid (*transmission tariff*). The majority of European countries (ENTSO-E, 2013) have point of connection tariffs. With the point of connection tariffs scheme, suppliers pay a linear tariff for the electricity injected into the grid, i.e., the electricity sold in their own market and the one sold in the other market. From the suppliers' point of view, a connection tariff is equivalent to an increase in generation costs. Given that electricity demand is very inelastic, an increase in generation costs is passed through to consumers that face an increase in equilibrium prices in both markets. This is in line with the pass-through literature (Marion and Muehlegger 2011; Fabra and Reguant 2014). For transmission tariffs, electricity suppliers would only pay a linear tariff for the electricity sold to the other market. Hence, similar to a trade model, firms only pay a transport cost for the goods sold in the other market. The analysis indicates that transmission tariffs are better than point of connection tariffs from the consumers' perspective.

[1] The term "transmission capacity constraint" is used throughout this article in the electrical engineering sense: a transmission line is constrained when the flow of power is equal to the capacity of the line, as determined by engineering standards.

[2] Fabra et al. (2006) show that the equilibrium outcome allocation does not change when firms submit single price offers for their entire capacity and when they submit a set of price-quantity offers.

When there are constraints on the possibility to export electricity to another market, the effective size of the market differs for the suppliers. The supplier located in the high-demand market faces a higher residual demand, while the supplier located in the low-demand market cannot sell its entire generation capacity. Therefore, the supplier located in the high-demand market has incentives to submit higher bids than the one located in the low-demand market (size effect). Hence, due to the limited transmission capacity, the equilibrium is asymmetric even if suppliers have identical production costs and production capacities.

Transmission costs also introduce an asymmetry. The supplier located in the low-demand market has to sell a large part of its generation capacity into the other market and thus, it faces a high transmission cost and has incentives to increase its bid. The transmission cost makes the supplier in the high-demand market more efficient in relative terms. In order to exploit its efficiency rent, it has incentives to submit lower bids and, for a sufficiently high transmission cost, the efficient supplier will even try to undercut the exporting supplier (cost effect). Hence, the introduction of transmission tariffs could reduce the bid of the supplier in the high-demand market and there are even cases where consumers would, on average, gain from the introduction of a transmission cost. Point of connection tariffs do not have the pro-competitive cost effect. This suggests that transmission tariffs would, in most cases, be better for market performance and consumers in comparison to point of connection tariffs.

With low transmission tariffs, an increase in the transmission capacity increases the competition between suppliers and the expected bids for both firms decrease. This reduces the profit for the supplier in the high demand market. The profit for the exporting supplier first increases when the transmission capacity increases, because it can export more. But for a sufficiently large transmission capacity, increased competition will dominate and more capacity will reduce the profit also for the exporting supplier. A third effect is that transmission payments will increase if exports increase. If the transmission costs are sufficiently high and fixed per unit exported, an increase in the transmission capacity will increase the bids. Therefore, an increase in transmission capacity could be anti-competitive if the transmission costs are sufficiently high.

A methodological contribution is that this paper is the first to introduce transmission constraints in models with Bertrand competition and capacity constrained production. Kreps and Scheinkman (1983) and Osborne and Pitchik (1986) characterize the equilibrium in a duopoly with production capacity constraints. Deneckere and Kovenock (1996) and Fabra et al. (2006) extend the analysis to include asymmetries in generation capacity and production costs. Hu et al. (2010) extend the analysis to multiple firms, but they have only found a close form solution for the equilibrium when the suppliers are symmetric. Rosenthal (1980) and Janseen and Moraga-González (2004) applied similar techniques to extend the analysis to multiple firms in different sales models. Transmission constraints have been considered in other types of oligopoly models. Borenstein et al. (2000) characterize the equilibrium in an electricity network where suppliers compete in quantities as in a Cournot game. Holmberg and Philpott (2012) solve for symmetric supply function equilibria in electricity networks when demand is uncertain ex-ante, but they do not consider any transmission costs. Escobar and Jofré (2010) analyze the effect of transmission losses, a transmission cost, on equilibrium outcome allocations, but they neglect transmission constraints. Hence, this paper is the first to characterize equilibrium outcomes in networks with both transmission constraints and transmission costs. The paper also shows that the interaction between transmission costs and transmission constraints is non-straightforward.

The results of this paper could also be of relevance for the trade literature. For instance, Krugman (1980), Flam and Helpman (1987), Brezis et al. (1993) and Motta et al. (1997) explain differences in prices and profits in international trade models based on product differentiation or product cost advantages. By introducing transport costs and transport constraints, this paper finds related results, even if the product is homogeneous and suppliers have identical production technologies.

The article proceeds as follows. Section 2 describes the model and characterizes the equilibrium in the presence of transmission capacity constraints. Section 3 characterizes the equilibrium in the presence of transmission capacity constraints and transmission tariffs. Section 4 concludes the paper. The analysis of point of connection tariffs and all proofs are found in the Appendix.

2 The model

Set up of the model. There exist two electricity markets, market North and market South, that are connected by a transmission line with capacity T. When firms transmit electricity through the grid from one market to the other, they face a symmetric linear[3] transmission tariff t. In order to reduce transmission losses,[4] the transmission tariffs in the majority of European countries have a locational and a seasonal component.[5]

There exist two duopolists with capacities k_n and k_s, where subscript n means that the supplier is located in market North and subscript s means that the supplier is located in market South. The suppliers' marginal costs of production are c_n and c_s. In this paper, I analyze the effect of transmission capacity constraints and transmission costs on the equilibrium. In order to focus on this effect, I assume that suppliers are symmetric in capacity $k_n = k_s = k > 0$ and symmetric in costs $c_n = c_s = c = 0$. The level of demand in any period, θ_n in market North and θ_s in market South, is a random variable uniformly distributed that is independent across markets[6] and independent of market price, i.e.,

[3]The transmission tariffs are linear in electricity markets. However, the model can be modified to assume convex costs. When the transmission costs are convex, the existence of the equilibrium is guaranteed by Dixon (1984).

[4]Electricity suppliers pay a linear tariff that depends on the location and the season/period-of-day. The locational component of the tariff penalizes the injection of electricity in points of the grid that generate high flows of electricity. The seasonal/period-of-day component of the tariff penalizes the transmission of electricity when the losses are larger. For a complete analysis of losses in Europe and a complete description of the algorithm implemented to work out power losses, consult the document "ENTSO-E ITC Transit Losses Data Report 2013".

[5]The locational and seasonal component implies that suppliers face asymmetric linear tariffs. However, the model can easily be modified to introduce this type of asymmetries. For a comparison of European tariff systems, check out the document "ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2014".

[6]In the majority of electricity markets, demand in one market is higher than demand in the other market. Moreover, there exists the possibility of some type of correlation between demands across markets. In this paper, I assume uniform distribution and independence of demand. However, the model

perfectly inelastic. In particular, $\theta_i \in [\underline{\theta}_i, \overline{\theta}_i] \subseteq [0, k+T]$ is distributed according to some known distribution function $G(\theta_i)$, $i = n, s, i \neq j$.

The capacity of the transmission line can be lower than the installed capacity in each market $T \leq k$, i.e. the transmission line could be congested for some realization of demands (θ_s, θ_n).

Timing of the game. Having observed the realization of demands $\theta \equiv (\theta_s, \theta_n)$, each supplier simultaneously and independently submits a bid specifying the minimum price at which it is willing to supply up to its capacity, $b_i \leq P$, $i = n, s$, where P denotes the "market reserve price", possibly determined by regulation.[7] Let $b \equiv (b_s, b_n)$ denote a bid profile. On basis of this profile, the auctioneer calls suppliers into operation. If suppliers submit different bids, the capacity of the lower-bidding supplier is dispatched first. Without lost of generality, assume that $b_n < b_s$. If the capacity of supplier n is not sufficient to satisfy total demand $(\theta_s + \theta_n)$ in the case of the transmission line not being congested, or $(\theta_n + T)$ in the case of the transmission line being congested,[8] the higher-bidding supplier's capacity, supplier s, is then dispatched to serve residual demand, $(\theta_s + \theta_n - k)$ if the transmission line is not congested, or $(\theta_s - T)$ if the transmission line is congested. If the two suppliers submit equal bids, then supplier i is ranked first with probability ρ_i, where $\rho_n + \rho_s = 1$, $\rho_i = 1$ if $\theta_i > \theta_j$, and $\rho_i = \dfrac{1}{2}$ if $\theta_i = \theta_j$, $i = n, s$, $i \neq j$. The implemented tie breaking rule is such that if the bids of both suppliers are equal and demand in market i is larger than demand in region j, the auctioneer first dispatches the supplier located in market i.

The output allocated to supplier $i, i = n, s$, denoted by $q_i(\theta, b)$, is given by

$$q_i(b;\theta,T) = \begin{cases} min\{\theta_i + \theta_j, \theta_i + T, k_i\} & \text{if } b_i < b_j \\ \rho_i min\{\theta_i + \theta_j, \theta_i + T, k_i\} + & \\ \qquad [1-\rho_i] max\{0, \theta_i - T, \theta_i + \theta_j - k_j\} & \text{if } b_i = b_j \\ max\{0, \theta_i - T, \theta_i + \theta_j - k_j\} & \text{if } b_i > b_j \end{cases} \tag{1}$$

The output function has an important role in determining the equilibrium and thus, it is explained in detail. Below, I describe the construction of supplier n's output function; the one for supplier s is symmetric.

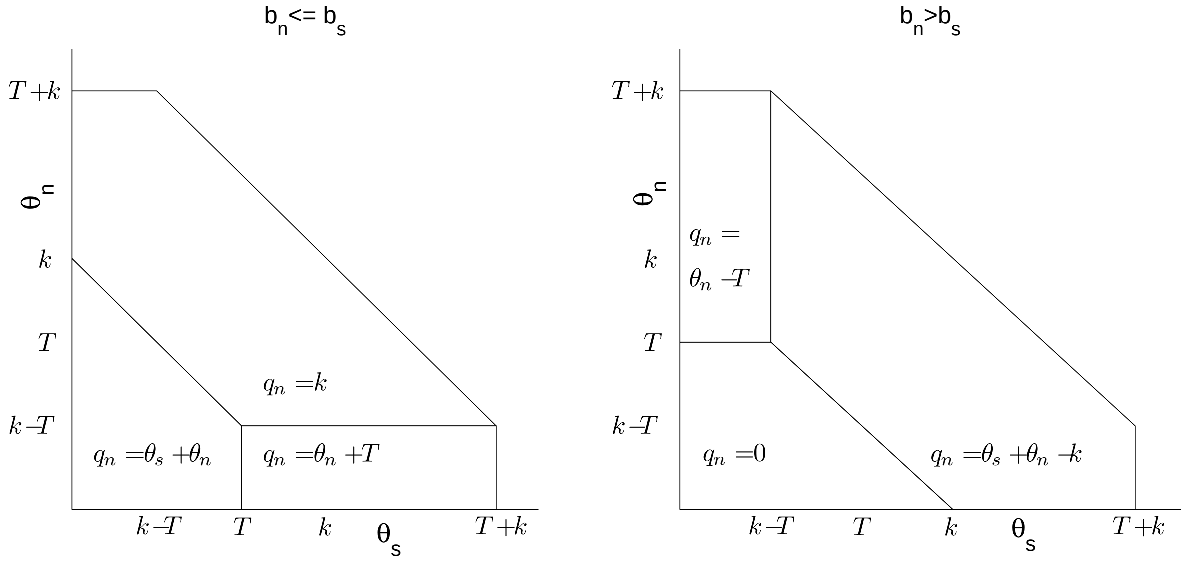
The total demand that can be satisfied by supplier n when it submits the lower bid $(b_n < b_s)$ is defined by $min\{\theta_n + \theta_s, \theta_n + T, k\}$. The realization of (θ_s, θ_n) determines three different areas (left-hand panel in figure 1).

can easily be modified to introduce different distributions of demand and correlation between demands across markets.

[7] P can be interpreted as the price at which all consumers are indifferent between consuming and not consuming, or a price cap imposed by the regulatory authorities. See von der Fehr and Harbord (1993, 1998).

[8] When the demand in market South is larger than the transmission line capacity $\theta_s > T$, supplier n can only satisfy the demand in its own region and T units of demand in region South $(\theta_n + T)$. Below in this section, I explain in detail the total demand and the residual demand that can be satisfied by each supplier.

Figure 1: Output function for supplier n. ($k_n = k_s = 60, T = 40$)



$$min\{\theta_n + \theta_s, \theta_n + T, k\} = \begin{cases} \theta_s + \theta_n & \text{if } \theta_n \leq k - \theta_s \text{ and } \theta_s < T \\ \theta_n + T & \text{if } \theta_n < k - T \text{ and } \theta_s > T \\ k & \text{if } \theta_n > k - \theta_s;\ \theta_s \in [0, T] \\ & \text{or if } \theta_n > k - T;\ \theta_s \in [T, k+T] \end{cases}$$

When demand in both markets is low, supplier n can satisfy total demand $(\theta_s + \theta_n)$. If the demand in market South is larger than the transmission capacity $\theta_s > T$, supplier n cannot satisfy the demand in market South, even when it has enough generation capacity for this; therefore, the total demand that supplier n can satisfy is $(\theta_n + T)$. Finally, if the demand is large enough, the total demand that supplier n can satisfy is its own generation capacity.

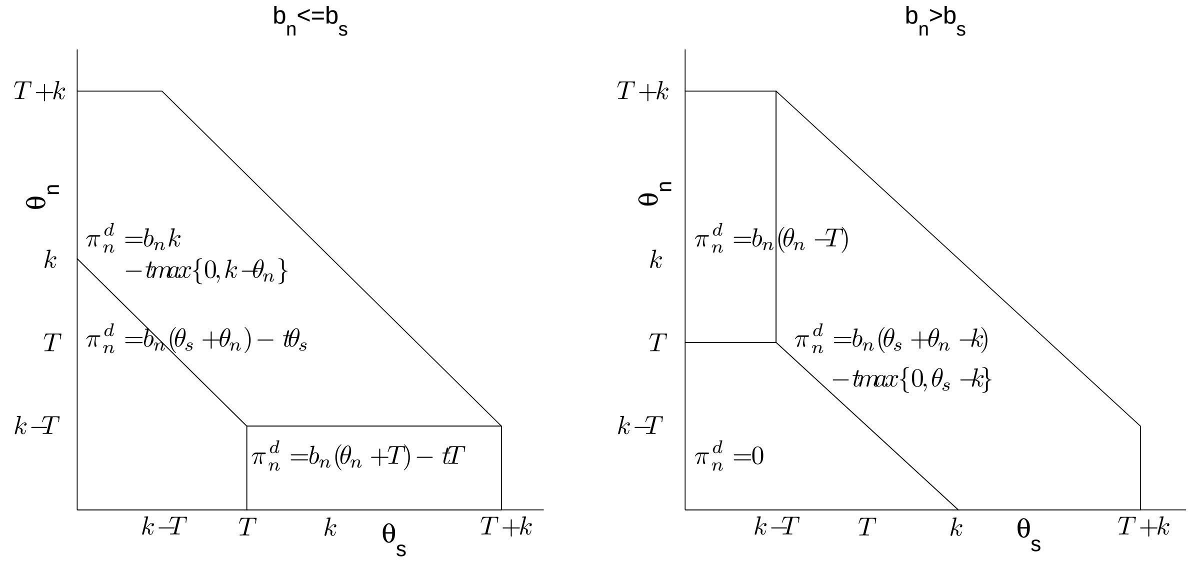
The residual demand that supplier n satisfies when it submits the higher bid $(b_n > b_s)$ is defined by $max\{0, \theta_n - T, \theta_s + \theta_n - k\}$. The realization of (θ_s, θ_n) determines three different cases (right-hand panel in figure 1).

$$max\{0, \theta_n - T, \theta_s + \theta_n - k\} = \begin{cases} 0 & \text{if } \theta_n < T;\ \theta_s \in [0, k-T] \\ & \text{or } \theta_n < k - \theta_s;\ \theta_s \in [k-T, k] \\ \theta_n - T & \text{if } \theta_n > T \text{ and } \theta_s \in [0, k-T] \\ \theta_s + \theta_n - k & \text{if } \theta_n > k - \theta_s;\ \theta_s \in [k-T, T+k] \end{cases}$$

When demand in both markets is low, supplier s satisfies total demand and therefore, the residual demand that remains for supplier n is zero. The total demand that supplier s can satisfy diminishes due to the transmission constraint. As soon as demand in market North is larger than the transmission capacity $(\theta_n > T)$, it cannot be satisfied by supplier s and thus, some residual demand $(\theta_n - T)$ remains for supplier n. When total demand is large enough, supplier s cannot satisfy total demand and some residual demand $(\theta_s + \theta_n - k)$ remains for supplier n.

Finally, the payments are worked out by the auctioneer. When the auctioneer runs a

Figure 2: Profit function for supplier n. ($k_n = k_s = 60, T = 40, t > 0$)



discriminatory price auction,[9] the price received by a supplier for any positive quantity dispatched by the auctioneer is equal to its own bid. Hence, for a given realization of demands $\theta \equiv (\theta_s, \theta_n)$ and a bid profile $b \equiv (b_s, b_n)$, supplier n's profits, $i = n, s$, can be expressed as

$$\pi_i^d(b; \theta, T, t) = \begin{cases} (b_i - c_i) min\left\{\theta_i + \theta_j, \theta_i + T, k\right\} - & \\ \quad tmax\left\{0, min\left\{\theta_j, T, k - \theta_i\right\}\right\} & \text{if } b_i \leq b_j \text{ and } \theta_i > \theta_j \\ (b_i - c_i) max\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\} - & \\ \quad tmax\left\{0, \theta_j - k\right\} & \text{otherwise} \end{cases}$$

If $b_n \leq b_s$ and $\theta_n \geq \theta_s$, supplier n's payoff function is $\pi_n^d(b; \theta, T) = (b_n - c_n)$ $min\left\{\theta_n + \theta_s, \theta_n + T, k\right\}$. In addition to this expression, due to the transmission costs, supplier n is charged a transmission cost t for the power sold in market South. The transmission costs have four different possible values: $t\theta_s$ when the realization of demand in market North is low and the transmission line is not congested; tT when the realization of demand in market North is low and the transmission line is congested; when the realization of demand in market North is high but lower than its generation capacity, the transmission costs are $t(k - \theta_n)$; finally, when demand in market North is larger than the generation capacity k, supplier n cannot sell any electricity in market South and the transmission costs are zero. Hence, after adding the transmission costs, supplier n's payoff is equal to $\pi_n^d(b; \theta, T, t) = (b_n - c_n) min\left\{\theta_n + \theta_s, \theta_n + T, k\right\} - tmax\left\{0, min\left\{\theta_s, T, k - \theta_n\right\}\right\}$ (left-hand panel, figure 2).

In the rest of the cases, supplier n is dispatched last and satisfies the residual demand. Supplier n's payoff function is $\pi_n^d(b; \theta, T, t) = (b_n - c_n) min\left\{\theta_s + \theta_n, \theta_n + T, k\right\}$.

[9]The aim of this paper is to characterize the equilibrium in an electricity auction in the presence of transmission constraints and transmission costs. I have decided to focus on discriminatory auctions because the equilibrium is unique and therefore, it is easier to make a comparative static analysis. However, using the approach presented in Fabra et al. (2006) and taking into account the allocation of transmission rights (Blázquez, 2014), it is simple to characterize the equilibrium when the auction is uniform.

In addition to this expression, due to the transmission costs, supplier n is charged a transmission cost t for the residual demand satisfied in market South. Therefore, after adding the transmission costs, supplier n's payoff is equal to $\pi_n^d(b;\theta,T) = (b_n - c_n)max\left\{0,\theta_n - T, \theta_s + \theta_n - k\right\} - tmax\left\{0,\theta_s - k\right\}$ (right-hand panel, figure 2).

3 Effect of transmission capacity constraints

In the presence of transmission capacity constraints, the size of the market differs for both suppliers. The supplier located in the high-demand market faces **a** higher residual demand and the supplier located in the low-demand market cannot sell its entire generation capacity. In this section, I characterize the equilibrium in the presence of transmission capacity constraints and *zero* transmission costs and then I analyze the effect of an increase in transmission capacity.

Lemma 1. When the realization of demands (θ_s, θ_n) is low (area A), the equilibrium is in pure strategies. When the realization of demands (θ_s, θ_n) is intermediate (areas $A1, B1$) or high (area $B2$), a pure strategy equilibrium does not exist (figure 3).

Proof. When the realization of demands (θ_s, θ_n) is low (area A), both suppliers have enough capacity to satisfy total demand in both markets and the transmission line is not congested. Therefore, they compete fiercely to be dispatched first in the auction. Hence, the equilibrium is the typical Bertrand equilibrium where both suppliers submit bids equal to their marginal cost.

When the realization of demands (θ_s, θ_n) is intermediate (areas $A1$, $B1$) or high (area $B2$), at least one of the suppliers faces a positive residual demand. Therefore, a pure strategy equilibrium does not exist. First, an equilibrium such that $b_i = b_j = c$ does not exist because at least one supplier has an incentive to increase its bid and satisfy the residual demand. Second, an equilibrium such that $b_i = b_j > c$ does not exist because at least one supplier has the incentive to undercut the other to be dispatched first. Finally, an equilibrium such that $b_j > b_i > c$ does not exist because supplier i has the incentive to shade the bid submitted by supplier j. $\square$

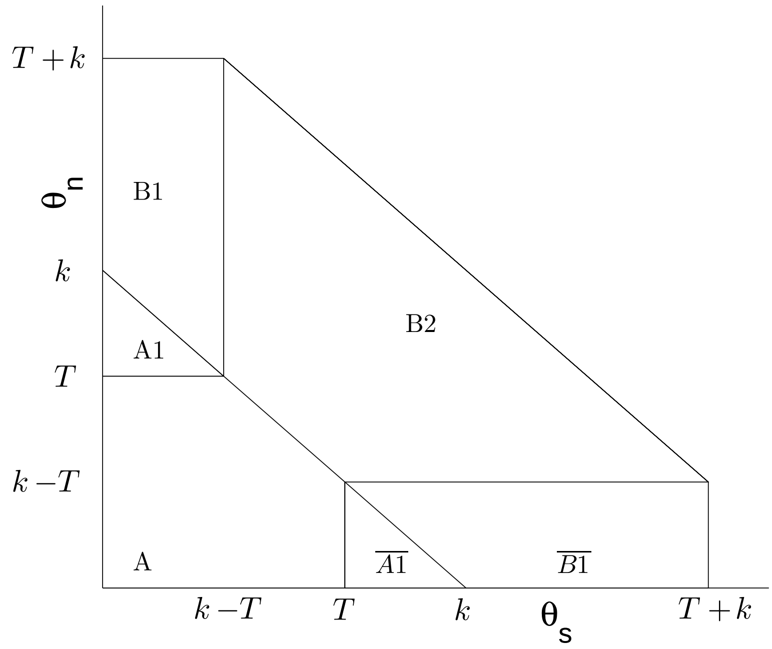
When the realization of demands (θ_s, θ_n) is intermediate or high, a pure strategy equilibrium does not exist. However, the model satisfies the properties[10] established by Dasgupta and Maskin (1986) which guarantee that a mixed strategies equilibrium exists.

Lemma 2. In the presence of transmission constraints. In a mixed strategy equilibrium, no supplier submits a bid lower than bid $(\underline{b}_i)$ such that $\underline{b}_i min\left\{\theta_i + \theta_j, \theta_i + T, k\right\} = Pmax\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\}$. Moreover, the support of the mixed strategy equilibrium for both suppliers is $S = \left[max\left\{\underline{b}_i, \underline{b}_j\right\}, P\right]$.

Proof. Each supplier can guarantee for itself the payoff $Pmax\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\}$, because each supplier can always submit the highest bid and satisfy the residual demand. Therefore, in a mixed strategy equilibrium, no supplier submits a bid that generates a payoff equilibrium lower than $Pmax\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\}$. Hence, no supplier submits a bid

[10] In annex one, proposition one, I prove that the model satisfies the properties established by Dasgupta and Maskin which guarantee that a mixed strategy equilibrium exists.

Figure 3: Equilibrium areas ($k_n = k_s = k = 60, T = 40, c = 0$)



lower than $\underline{b}_i$, where $\underline{b}_i$ solves $\underline{b}_i min \{\theta_i + \theta_j, \theta_i + T, k\} = Pmax \{0, \theta_i - T, \theta_i + \theta_j - k\}$.

No supplier can rationalize submitting a bid lower than $\underline{b}_i, i = n, s$. In the case when $\underline{b}_i = \underline{b}_j$, the mixed strategy equilibrium and the support are symmetric. In the case when $\underline{b}_i < \underline{b}_j$, supplier i knows that supplier j never submits a bid lower than $\underline{b}_j$. Therefore, in a mixed strategy equilibrium, supplier i never submits a bid b_i such that $b_i \in \left(\underline{b}_i, \underline{b}_j\right)$, because supplier i can increase its expected payoff choosing a bid b_i such that $b_i \in \left[\underline{b}_j, P\right]$. Hence, the equilibrium strategy support for both suppliers is $S = \left[max \left\{\underline{b}_i, \underline{b}_j\right\}, P\right]$ $\square$

Using Lemmas one and two, I characterize the equilibrium.

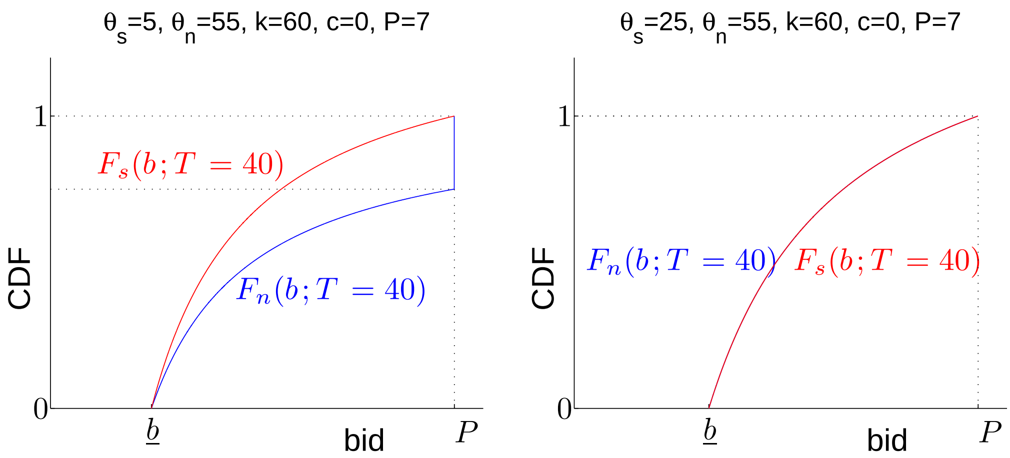
Proposition 1. In the presence of transmission constraints, the characterization of the equilibrium falls into one of the next two categories.

i Low demand (area A). The equilibrium strategy pair is in pure strategies.

ii Intermediate demand (areas $A1$, $B1$) and high demand (area $B2$). The equilibrium strategy pair is in mixed strategies.

When the realization of demands (θ_s, θ_n) is low, suppliers compete fiercely to be dispatched first in the auction and the equilibrium is the typical Bertrand equilibrium in which both suppliers submit bids equal to their marginal cost. When the realization of demands (θ_s, θ_n) is intermediate, due to the scarcity of transmission capacity, the supplier located in the high-demand market faces a higher residual demand and the supplier located in the low-demand market cannot sell its entire generation capacity. Therefore, the equilibrium is an asymmetric mixed strategy equilibrium where the supplier located in the high-demand market randomizes submitting higher bids with a higher probability,

Figure 4: Discriminatory auction. Mixed strategy equilibrium



i.e., its cumulative distribution function stochastically dominates the cumulative distribution function of the supplier located in the low-demand market (left-hand panel, figure 4). Finally, when the realization of demands (θ_s, θ_n) is high, the transmission capacity is not binding, but the generation capacity is. Therefore, both suppliers face the same residual and total demand and the equilibrium constitute a symmetric mixed strategy equilibrium in which both suppliers randomize using the same cumulative distribution function (right-hand panel, figure 4).

In the presence of transmission constraints, there are two relevant constraints that explain the results. When the generation capacity is binding, even when the realization of demands is asymmetric, the equilibrium is symmetric.[11] When the transmission capacity is binding, even when the firms are symmetric in generation capacity and production costs, the equilibrium is asymmetric.

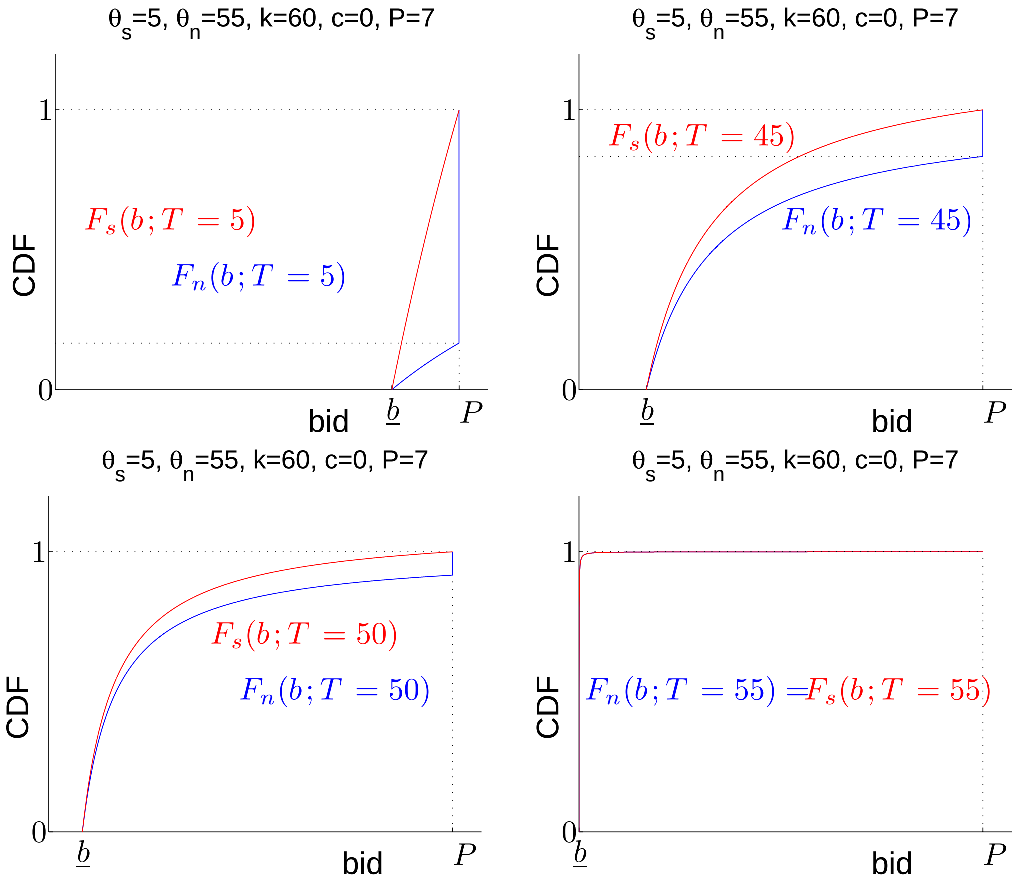
To conclude this section, I analyze the effect of an increase in transmission capacity on equilibrium outcome allocations.

Proposition 2. In the presence of transmission constraints. An increase in transmission capacity $(\triangle T)$ reduces the lower bound of support $\underline{b}$ and reduces the expected bids for both suppliers (an increase in transmission capacity is pro-competitive). Moreover, an increase in transmission capacity reduces the profit of the supplier located in the high-demand market. However, an increase in transmission capacity modifies the profit of the supplier located in the low-demand market in a non monotonic pattern (table 1 and figures 5 and 6).

An increase in transmission capacity modifies the market size as does suppliers' strategies. When the transmission capacity is very low, the supplier located in the high-demand market faces a high residual demand and the supplier located in the low-demand market cannot sell its entire generation capacity. Therefore, the supplier located in the high-demand market submits higher bids than the one located in the low-demand market and

[11]In the next section, I introduce transmission tariffs. In the presence of transmission costs, the realization of demands becomes very relevant because the transmission costs are larger for the supplier located in the low-demand market and the equilibrium is asymmetric.

Figure 5: Increase in transmission capacity $\triangle T$. Cumulative Distribution Function



the cumulative distribution function of the supplier located in the high-demand market stochastically dominates that of the supplier located in the low-demand market (top-left panel, figure 5). When the transmission capacity increases, the supplier located in the high-demand market faces a reduction in its residual demand and the supplier located in the low-demand market faces an increase in the demand that it can satisfy. Therefore, the cumulative distribution function becomes more symmetric (top-right and bottom-left panels). When the transmission capacity is high enough, the transmission line is not congested and the residual and the total demand that both suppliers face are equal; in that case, the equilibrium is symmetric and both suppliers assign probability one to the lower bid (bottom-right panel).

The change in suppliers' strategies induced by an increase in transmission capacity modifies the main variables of the model. An increase in transmission capacity reduces the residual demand and according to lemma two, the lower bound of the support decreases (left-hand panel, figure 6; column two of table 1). A decrease in the lower bound of the support implies that both suppliers randomize submitting lower bids and therefore, the expected bid decreases for both suppliers (right-hand panel, figure 6; columns five and seven of table 1). Finally, an increase in transmission capacity reduces the expected bid and the residual demand of the supplier located in the high-demand market as does its expected profit. In contrast, an increase in transmission capacity reduces the expected bid and increases the total demand of the supplier located in the low-demand market. When the transmission capacity is low, the increase in demand dominates the decrease

Figure 6: Increase in transmission capacity $\triangle T$. Main variables

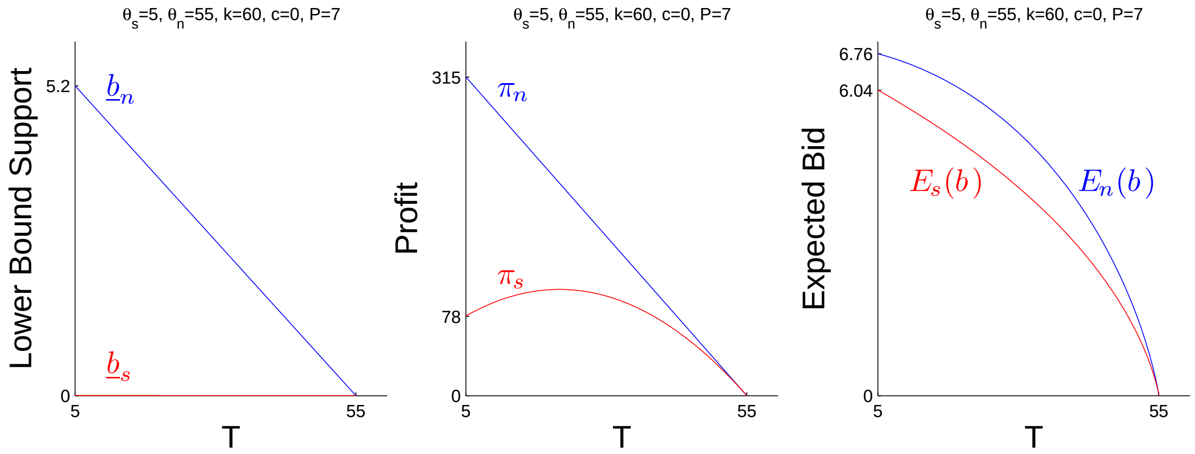


Table 1: Increase in transmission capacity $\triangle T$. Main variables. ($\theta_s = 5$, $\theta_n = 55$, $k = 60$, $c = 0$, $P = 7$)

T	$\underline{b}$	π_n	π_s	$E_n(b)$ Ana.	$E_n(b)$ Sim.	$E_s(b)$ Ana.	$E_s(b)$ Sim.
0	–	385.07	35	7	7	7	7
5	5.835	350.1	58.35	6.8971	6.8963	6.3795	6.3830
15	4.668	280.08	93.36	6.5592	6.5587	5.6770	5.6780
25	3.501	210.06	105.03	5.9264	5.9261	4.8530	4.8532
35	2.335	140.1	93.4	4.8981	4.8981	3.8464	3.8476
45	1.168	70.08	58.4	3.2587	3.2589	2.5102	2.5109
55	0.001	0.06	0.06	0.0089	0.0093	0.0087	0.0093

$E_n(b)$ Ana. and $E_s(b)$ Ana. are the expected values obtained using the analytical expressions presented in proposition one and $E_n(b)$ Sim. and $E_s(b)$ Sim. are the expected values obtained using the simulation explained in detail in Annex 3.

I have assumed that demand in market North (θ_n) is equal to 55.01 to avoid computational problems. This is the reason why the variables in the last row are not exactly equal to zero.

in the expected bid and its expected profit increases. However, when the transmission capacity is large enough, the decrease in bids dominates and its expected profit decreases (central panel, figure 6; columns three and four, table 1.)

Increases in transmission capacity have historically been justified as a way of enhancing competition between markets. However, as I have shown in proposition two, an increase in transmission capacity modifies the profit of the supplier located in the low-demand market and this might increase the competition within a market. For the sake of the argument, imagine that a small hydro-power plant that faces a fixed entry cost would like to install some generation capacity in the low-demand market. When there is no transmission capacity between markets, due to the reduced size of the market, the supplier cannot cover its fixed entry cost. However, if the transmission line increases, the size of the market increases and the supplier could enter the low-demand market. This entry might increase the competition within the low-demand market.

4 Effect of transmission capacity constraints and transmission costs

In the presence of transmission capacity constraints, the size of the market differs for both suppliers. In the presence of transmission costs, the transmission cost differs for both suppliers depending on the realization of the demand. The supplier located in the low-demand market must sell a large part of its generation capacity into the other market and thus, it faces a larger transmission cost than the supplier located in the high-demand market. In this section, I characterize the equilibrium in the presence of transmission capacity constraints and *positive* transmission costs.

Lemma 3. When the realization of demands (θ_s, θ_n) is low (area A) the equilibrium is in pure strategies. When the realization of demands (θ_s, θ_n) is intermediate (area $A1$) and the transmission costs are high, the equilibrium is in pure strategies; otherwise, a pure strategies equilibrium does not exist. When the realization of demands (θ_s, θ_n) is intermediate (areas $B1a, B1b$) or high (area $B2a, B2b$), a pure strategy equilibrium does not exist (figure 7). Moreover, due to the presence of transmission costs, the pure strategy equilibria are asymmetric.

Proof. When the realization of demands (θ_s, θ_n) is low (area A), both suppliers have enough capacity to satisfy total demand and the transmission line is not congested. Therefore, the competition to be dispatched first is fierce. Moreover, the supplier located in the high-demand market (supplier j) faces lower transmission costs. Hence, the equilibrium is the typical Bertrand equilibrium with asymmetries in "costs" [12] where the supplier located in the high-demand market extracts the efficiency rents. The *pure strategies equilibrium* is $b_i = b_j = \dfrac{t\theta_j}{\theta_i + \theta_j}$.

The *equilibrium profit* is:

$$\overline{\pi}_i = (\theta_i + \theta_j)\frac{t\theta_j}{\theta_i + \theta_j} - t\theta_j = 0; \;\; \overline{\pi}_j = (\theta_i + \theta_j)\frac{t\theta_j}{\theta_i + \theta_j} - t\theta_i = t(\theta_j - \theta_i) > 0$$

The *equilibrium price* is $\dfrac{t\theta_j}{\theta_i + \theta_j}$

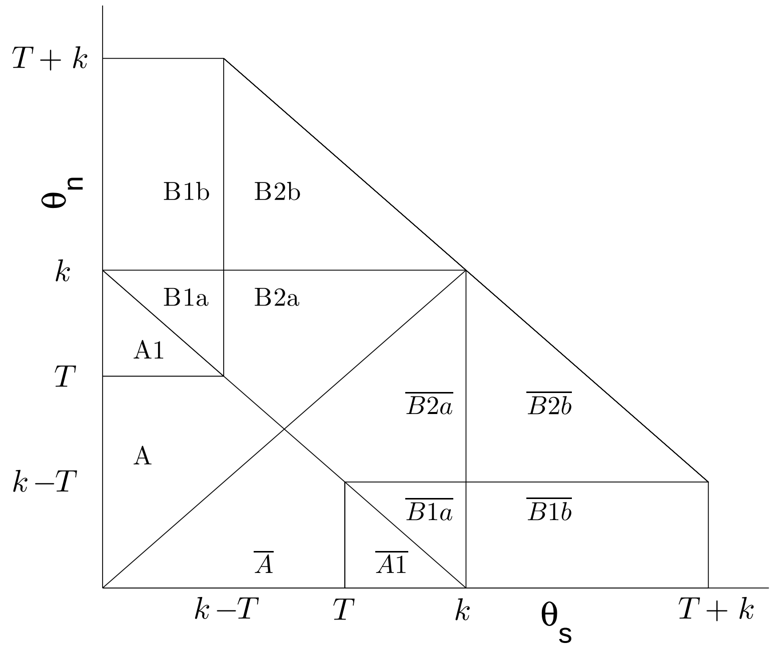
Electricity flows from the high-demand market to the low-demand market.

When the demand belongs to area $A1$ (figure 7), the transmission constraint binds for the supplier located in the low-demand market (supplier i); therefore, only the supplier located in the high-demand market can satisfy total demand. The supplier located in the high-demand market prefers to submit a low bid and extract the efficiency rent instead of submitting a high bid and satisfying the residual demand if $(\theta_i+\theta_j)\dfrac{tT}{\theta_i + T} - t\theta_i \geq P(\theta_i - T)$. In such a case, the pure strategies equilibrium is $b_i = b_j = \dfrac{tT}{\theta_i + T}$.

The *equilibrium profit* is:

[12] It is important to emphasize that the generation costs are symmetric and equal to zero. In this model, the asymmetries in costs are due to the transmission costs.

Figure 7: Equilibrium areas ($k_n = k_s = k = 60, T = 40, c = 0, t > 0$)



$$\overline{\pi}_i = (\theta_i + T)\frac{tT}{\theta_i + T} - tT = 0; \;\; \overline{\pi}_j = (\theta_i + \theta_j)\frac{tT}{\theta_i + T} - t\theta_i > 0$$

The *equilibrium price* is $\dfrac{tT}{\theta_i + T}$

The electricity flows from the high-demand market to the low-demand market.

In the rest of the cases, a pure strategies equilibrium does not exist and the proof proceeds as in lemma one $\square$

When the realization of demands (θ_s, θ_n) is intermediate or high and the auction is discriminatory, a pure strategy equilibrium does not exist. However, the model satisfies the properties established by Dasgupta and Maskin (1986) which guarantee that a mixed strategy equilibrium exists.

Lemma 4. In the presence of transmission constraints and *positive* transmission costs. In a mixed strategy equilibrium, no supplier submits a bid lower than bid $(\underline{b}_i)$ such that

$$\underline{b}_i min\left\{\theta_i + \theta_j, \theta_i + T, k\right\} - tmax\left\{0, min\left\{\theta_j, T, k - \theta_i\right\}\right\} =$$
$$Pmax\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\} - tmax\left\{0, \theta_j - k\right\}.$$

Moreover, the support for the mixed strategy equilibrium for both suppliers is $S = \left[max\left\{\underline{b}_i, \underline{b}_j\right\}, P\right]$.

Proof. The proof proceeds as in lemma two. $\square$

Using lemmas three and four, I characterize the equilibrium.

Proposition 3. In the presence of transmission constraints and transmission costs, the characterization of the equilibrium falls into one of the next three categories.

i Low demand (area A). The equilibrium strategy pair is in pure strategies.

ii Intermediate demand (area $A1$). When the transmission cost is high, the equilibrium strategy pair is in pure strategies. In contrast, when the transmission cost is low, the equilibrium strategy pair is in mixed strategies.

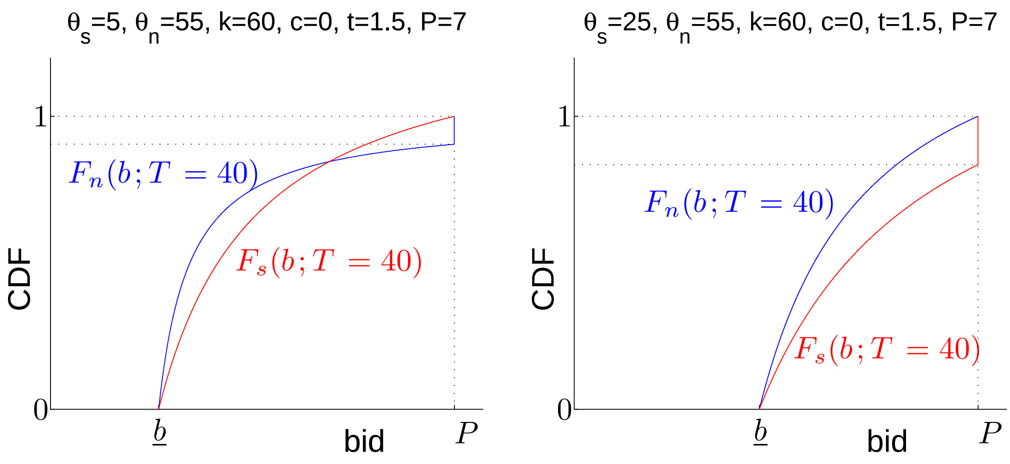
iii Intermediate demand (areas $B1a$, $B1b$) and high demand (areas $B2a$, $B2b$). The equilibrium strategy pair is in mixed strategies.

When the realization of demands (θ_s, θ_n) is low, suppliers compete fiercely to be dispatched first in the auction and the equilibrium is the typical Bertrand equilibrium with asymmetries in costs where the supplier located in the high-demand market extracts the efficiency rents.

When the realization of demands (θ_s, θ_n) belongs to area $A1$ the transmission constraint binds for the supplier located in the low-demand market (supplier i); therefore, only the supplier located in the high-demand market can satisfy total demand. If the transmission costs are high enough, the supplier located in the high-demand market prefers to submit a low bid to extract the efficiency rents. In contrast, when realization of demands (θ_s, θ_n) belongs to area $A1$ and the transmission costs are high or when the realization of demands (θ_s, θ_n) belongs to areas $B1a$ or $B1b$, due to the scarcity of transmission capacity, the supplier located in the high-demand market faces a higher residual demand and the supplier located in the low-demand market cannot sell its entire generation capacity. Therefore, the supplier located in the high-demand market has higher incentives to submit high bids than the one located in the low-demand market (size effect). However, due to the presence of transmission costs, the supplier located in the high-demand market faces lower transmission costs and to exploit its efficiency rents, it has higher incentives than the supplier located in the low-demand market to submit low bids (cost effect). The cost and size effects work in the opposite direction and no stochastic dominance range can be established between the cumulative distribution functions of both suppliers (left-hand panel, figure 8). This is in contrast to the *zero* transmission costs case where only the size effect drives the results and the cumulative distribution function of the supplier located in the high-demand region stochastically dominates the cumulative distribution function of the supplier located in the low-demand market (left-hand panel, figure 4).

When the realization of demands (θ_s, θ_n) is high, the transmission capacity is not binding, but the generation capacity is. Therefore, both suppliers face the same demand. However, due to the transmission costs, the supplier located in the high-demand market faces lower transmission costs and submits lower bids (cost effect). Hence, the cumulative distribution function of the supplier located in the low-demand market stochastically dominates the cumulative distribution function of the supplier located in the high-demand market (right-hand panel, figure 8). This is in contrast to the *zero* transmission costs case where both suppliers randomize using the same cumulative distribution function (right-hand panel, figure 4).

Figure 8: Discriminatory auction. Mixed strategy equilibrium



Finally, when the realization of demands (θ_s, θ_n) is in the diagonal, both suppliers face the same demand and transmission costs. Therefore, the equilibrium is a symmetric mixed strategy equilibrium.

In the rest of this section, I analyze the effect of an increase in transmission capacity on the size and cost effects and thus, on equilibrium outcome allocations (as in the rest of the section, I assume that the suppliers pay a linear tariff only for the electricity sold in the other market).

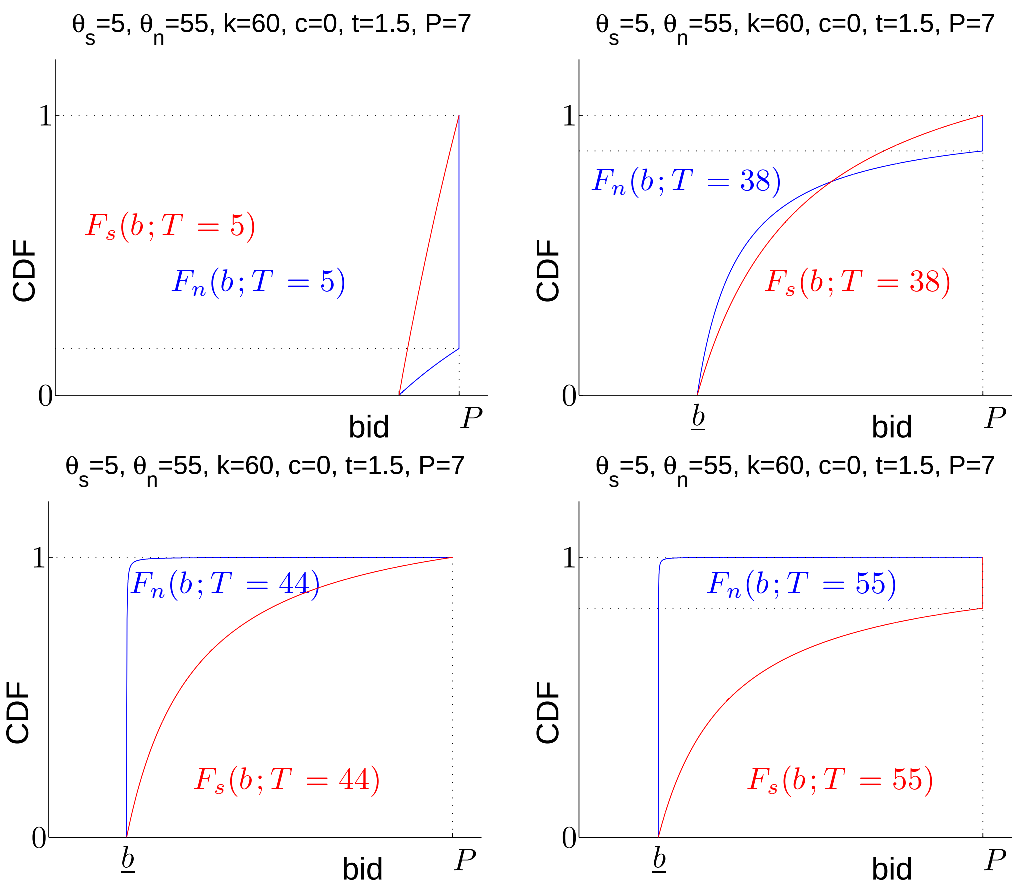
Proposition 4. An increase in transmission capacity ($\triangle T$) reduces the lower bound of the support of the supplier located in the high-demand market and increases the lower bound of the support of the supplier located in the low-demand market (left-hand panel, figure 10).

- When the lower bound of the support of the supplier located in the high-demand market is larger than the lower bound of the support of the supplier located in the low-demand market. An increase in transmission capacity reduces the expected bids of both suppliers (an increase in transmission capacity is pro-competitive), reduces the profit of the firm located in the high-demand market and modifies the profit of the supplier located in the low-demand market in a non-monotonic pattern.

- Otherwise, an increase in transmission capacity increases the expected bids of both suppliers (an increase in transmission capacity is anti-competitive), increases the expected profit of the supplier located in the high-demand market and does not modify the expected profit of the supplier located in the low-demand market (table 2; figures 9 and 10).

An increase in transmission capacity modifies the market size and the transmission costs and thus also suppliers' strategies. When the transmission capacity is very low, the size effect dominates and the cumulative distribution function of the supplier located in the high-demand market stochastically dominates that of the supplier located in the low-demand market (top-left panel, figure 9). When there is an increase in the transmission capacity, no cumulative distribution function stochastically dominates the other (top-right panel, figure 9). When there is a substantial increase in transmission capacity,

Figure 9: Increase in transmission capacity $\triangle T$. Cumulative Distribution Function



there is also an increase in transmission costs, especially for the supplier located in the low-demand market. In that case, the supplier located in the high-demand market submits lower bids than the one located in the low-demand market to extract the efficiency rents and the cumulative distribution function of the supplier located in the low-demand market stochastically dominates that of the supplier located in the high-demand market (bottom-left and bottom-right panels, figure 9).

The change in suppliers' strategies induced by an increase in transmission capacity modifies the main variables of the model. When the transmission capacity is sufficiently low ($T \leq 44$ for the numerical examples in table 2 and figures 9 and 10), the size effect dominates and an increase in transmission capacity induces the same changes in the variables as when the transmission costs are null (proposition two). Hence, an increase in transmission capacity decreases the lower bound of the support and therefore, decreases the expected bid for both suppliers. Hence, an increase in transmission capacity is pro-competitive (right-hand panel, figure 10; columns five and seven, table 2); reduces the expected profit of the supplier located in the high-demand market and modifies in a non-monotonic pattern the profit of the supplier located in the low-demand market (central panel, figure 10; columns three and four, table 2).

When the transmission capacity is high enough ($T > 44$), the cost effect dominates and an increase in transmission capacity increases the lower bound of the support (left-hand panel, figure 10). An increase in the lower bound of the support entailed that both

Figure 10: Increase in transmission capacity $\triangle T$. Main variables

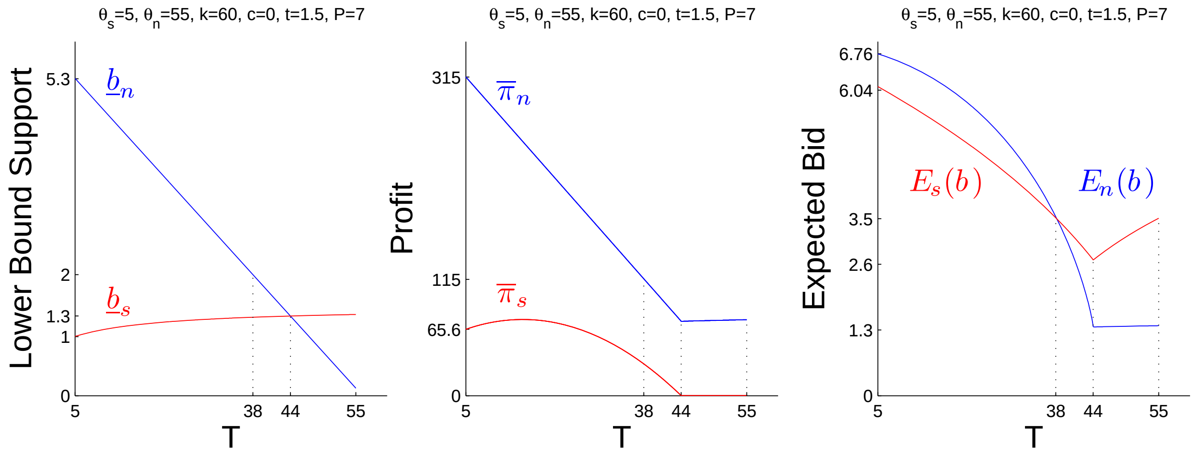


Table 2: Increase transmission capacity $\triangle T$. Main variables. ($\theta_s = 5$, $\theta_n = 55$, $k = 60$, $c = 0$, $t = 1.5$, $P = 7$)

T	$\underline{b}$	$\overline{\pi}_n$	$\overline{\pi}_s$	$E_n(b)$ Ana.	$E_n(b)$ Sim.	$E_s(b)$ Ana.	$E_s(b)$ Sim.
0	–	385.07	35	7	7	7	7
5	5.959	350.05	52.09	6.9079	6.9072	6.4495	6.4483
15	4.793	280.09	73.36	6.5206	6.5201	5.7472	5.7490
25	3.626	210.07	71.28	5.7253	5.7252	4.9294	4.9301
35	2.459	140.05	45.86	4.2942	4.2944	3.9306	3.9307
45	1.351	73.575	0	1.3569	1.3570	2.7299	2.7304
55	1.376	75.075	0	1.3821	1.3825	3.5073	3.5075

Here $E_n(b)$ Ana. and $E_s(b)$ Ana. constitute the expected values obtained using the analytical expressions presented in proposition one and $E_n(b)$ Sim. and $E_s(b)$ Sim. constitute the expected values obtained using the simulation explained in detail in Annex 3.

suppliers randomize submitting higher bids and therefore, the expected bid increases for both suppliers. Hence, an increase in transmission capacity is anti-competitive (right-hand panel, figure 10; columns five and seven, table 2). Finally, an increase in transmission capacity increases the expected profit of the supplier located in the high-demand market because it can exploit the efficiency rents more; in contrast, the expected profit of the supplier located in the low-demand market does not change because the increase in profits derived from an increase in the expected bid is compensated by the increase in transmission costs (central panel, figure 10; columns three and four, table 2).

5 Model comparison and consumer welfare.

As I have shown in the two previous sections, transmission constraints and transmission tariffs have important implications for strategies and equilibrium outcomes. In this section, I compare equilibrium outcome allocations and their effects on consumer welfare in the presence of transmission constraints when the transmission costs are zero and when the suppliers pay a linear transmission tariff. I also compare these results with the equi-

Table 3: Effect of transmission constraint and transmission costs on equilibrium outcome ($\theta_s = 5$, $\theta_n = 55$, $k = 60$, $c = 0$, $P = 7$)

	T	$\underline{b}$	$\overline{\pi}_n$	$\overline{\pi}_s$	$\overline{\pi} = \overline{\pi}_n + \overline{\pi}_s$	$E_n(b)$	$E_s(b)$	$\theta_n E_n(b) + \theta_s E_s(b)$
Model I	40	1.75	105	184	289	4.2	3.2	247
Model II	40	1.87	105	24	129	3.1	3.3	187
Model III	40	2.87	82.5	62	144.5	4.8	4	284

Model I: zero transmission costs. Model II: transmission tariff. Model III: point of connection tariff

librium in the presence of transmission constraints and the point of connection tariffs worked out in annex four.

When the transmission costs are zero and the transmission line is congested (Model I), the supplier located in the high-demand market faces a higher residual demand, while the supplier located in the low-demand market cannot sell its entire generation capacity (size effect). Therefore, the supplier located in the high-demand market has incentives to submit higher bids than the one located in the low-demand market. Given that the majority of consumers are located in the high-demand market, the aggregate cost for consumers is large (second row, column nine; table 3).

When transmission tariffs are implemented (Model II), the supplier located in the low-demand market faces a large increase in transmission costs and thus, its expected bid increases. In contrast, the supplier located in the high-demand market faces a small increase in transmission costs and for high enough transmission tariffs, it can be more profitable to extract the efficiency rents undercutting (in expectation) the supplier located in the low-demand market (cost effect). These changes in equilibrium prices induce a drastic decrease in the total cost that consumers pay for the purchase of electricity[13] (third row, column nine; table 3). Moreover, the presence of transmission costs induces a change in the flow of electricity.

When the suppliers face a point of connection tariff (Model III), they pay the same transmission tariff for the electricity sold in their own market and the one sold in the other market. Therefore, the competitive advantage (cost effect) derived from the location in the high-demand market disappears and equilibrium market outcomes exclusively depend on the size effect. Moreover, given that electricity demand is very inelastic, an increase in generation costs is passed through to consumers that face an increase in equilibrium prices in both markets. Hence, there is a decrease in consumer welfare (row four, column nine; table 3).

The comparison between the three models suggests that the introduction of transmission tariffs increases aggregate consumer welfare. In contrast, the point of connection tariffs always decrease aggregate consumer welfare.

[13] Downward et al. (2014) found that the introduction of a tax on suppliers' profit induces an increase in consumer welfare. However, in their analysis, the reduction in equilibrium prices is not induced by some type of cost effect, but by a change in firms' strategies to avoid the tax.

6 Conclusion

Electricity markets are moving through integration processes around the world. In such a context, there exists an intense debate to analyze the effect of transmission constraints and transmission costs on suppliers' strategies. The contribution of this paper is to characterize the outcome of an electricity market auction and how it depends on transmission constraints and transmission costs.

When there are constraints on the possibility to deliver electricity to a market, the effective size of the market differs for the suppliers. The supplier located in the high-demand market faces a higher residual demand and the one located in the low-demand market cannot sell its entire generation capacity. Therefore, the supplier located in the high-demand market has incentives to submit larger bids than the one located in the low-demand market (size effect). Hence, due to the scarcity of transmission capacity, the equilibrium is asymmetric even when the suppliers are symmetric in generation capacity and costs.

When the suppliers are charged a linear transmission tariff, they face different transmission costs depending on the realization of demand. The supplier located in the high-demand market faces lower transmission costs than the one located in the low-demand market and to exploit its efficiency rents, it has incentives to submit lower bids than the one located in the low-demand market (cost effect). Hence, the introduction of transmission tariffs could lower the bid of the supplier in the high-demand market and there are even cases where consumers would, on average, gain from the introduction of a transmission cost. Point of connection tariffs do not have the pro-competitive cost effect. This suggests that transmission tariffs would, in most cases, be better for market performance and consumers in comparison to point of connection tariffs.

An increase in transmission capacity induces non-monotonic changes in suppliers' profits. The consequences of an increase in transmission capacity depend considerably on whether there are any transmission costs. In the presence of transmission capacity constraints and zero transmission costs, an increase in transmission capacity is always pro-competitive. In the alternative scenario where suppliers pay a linear transmission tariff for the electricity sold in the other market, an increase in transmission capacity could be anti-competitive.

The characterization of the equilibrium in the presence of transmission constraints and transmission costs gives us the opportunity to use the toolbox of the models of competition with capacity constraints to best understand electricity markets. In particular, the model that I have developed in this paper can be used to analyze mergers between suppliers located in different markets and it can be used to analyze investment decisions in generation capacity at different points of the electricity grid.

The size and cost effects described in the paper could appear in models of competition with capacity constraints when the firms face asymmetries in capital and costs as in models presented in Kreps and Scheinkman (1983); Osborne and Pitchik (1986); Deneckere and Kovenock (1996) Fabra et al. (2006). Moreover, due to the size and cost effects, equilibrium firms' cumulative distribution functions do not dominate each other. This characteristic of the equilibrium has important implications for prices and consumer welfare. Our knowledge of these effects is still limited and thus, more study is required to best characterize equilibrium outcome allocations in the presence of some type of "size" and "cost" effects.

This basic model could also be useful to analyze new transmission tariff designs that include seasonal or geographical components.

Annex 1. The effect of transmission capacity constraints

Proposition 1. Characterization of the equilibrium in the presence of transmission constraints.

When demand is low (area A, figure 3): $b_n = b_s = c = 0$, the *equilibrium profit* is zero for both firms. No electricity flows through the grid.

When demand is intermediate (areas $A1$ and $B1$, figure 3) or high (area $B2$, figure 3). As I have proved in lemma one, a pure strategies equilibrium does not exist; however, the model presented in section two satisfies the properties established by Dasgupta and Maskin (1986) which guarantee that a mixed strategy equilibrium exists. In particular, the discontinuities of $\pi_i, \forall i, j$ are restricted to the strategies such that $b_i = b_j$. Furthermore, it is simple to confirm that by reducing its price from a position where $b_i = b_j$, a firm discontinuously increases its profit. Therefore, $\pi_i(b_i, b_j)$ is everywhere left lower semi-continuous in b_i and hence, weakly lower semi-continuous. Obviously, $\pi_i(b_i, b_j)$ is bounded. Finally, $\pi_i(b_i, b_j) + \pi_j(b_i, b_j)$ is continuous because discontinuous shifts in clientele from one firm to another only occur where both firms derive the same profit per customer. Therefore, theorem five in Dasgupta and Maskin (1986) applies and hence, a mixed strategy equilibrium exists.

The existence of the equilibrium is guaranteed by Dasgupta and Maskin (1986). However, they did not provide an algorithm to work out the equilibrium. Nevertheless, using the approach proposed by Karlin (1959), Shapley (1957), Shilony (1977), Varian (1980), Deneckere and Kovenock (1986), Osborne and Pitchik (1986) and Fabra et al. (2006), the equilibrium characterization is guaranteed by construction. I use the approach proposed by this branch of the literature to work out the mixed strategy equilibrium. In particular: first, I work out the general formulas of the *lower bound of the support*, the *cumulative distribution function*, the *probability distribution function*, the *expected equilibrium price* and the *expected profit*; second, I work out the particular formulas associated with each single area[14] in figure 3.

Lower Bound of the Support. The lower bound of the support is defined according to lemma two.

Cumulative Distribution Function.

In the first step, the payoff function for any firm is:

$$\begin{aligned}\pi_i(b) &= b\left[F_j(b) max\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\} + (1 - F_j(b)) min\left\{\theta_i + \theta_j, \theta_i + T, k\right\}\right] = \\ &= -bF_j(b)\left[min\left\{\theta_i + \theta_j, \theta_i + T, k\right\} - max\left\{0, \theta_i - T, \theta_i + \theta_j - k\right\}\right] + \\ &\quad bmin\left\{\theta_i + \theta_j, \theta_i + T, k\right\}\end{aligned} \tag{2}$$

In the second step, $\pi_i(b) = \overline{\pi}_i \forall b \in S_i, i = n, s$, where S_i is the support of the mixed strategies. Then,

[14] The general formulas that I will introduce below fully characterize the equilibrium. However, the equilibrium presents specific characteristics in each single area. In order to fully characterize the equilibrium, I have decided to write down the formulas for each single area.

$$
\begin{aligned}
\overline{\pi}_i &= -bF_j(b)\left[min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right]+\\
&\quad bmin\left\{\theta_i+\theta_j,\theta_i+T,k\right\}\Rightarrow\\
F_j(b) &= \frac{bmin\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-\overline{\pi}_i}{b\left[min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right]} \qquad (3)
\end{aligned}
$$

The third step, at $\underline{b}$, $F_i(\underline{b})=0\forall i=n,s$. Then,

$$
\overline{\pi}_i = \underline{b}min\left\{\theta_i+\theta_j,\theta_i+T,k\right\} \qquad (4)
$$

In the fourth step, plugging 4 into 3, I obtain the mixed strategies for both firms.

$$
\begin{aligned}
F_j(b) &= \frac{bmin\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-\underline{b}min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}}{b\left[min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right]}=\\
&= \frac{min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}}{min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}}\frac{b-\underline{b}}{b}\quad\forall i=n,s \qquad (5)
\end{aligned}
$$

For further reference:
$L_i(b)=bmin\left\{\theta_i+\theta_j,\theta_i+T,k\right\}$ and
$H_i(b)=bmax\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}$.

It is easy to verify that equation $F_j(b)\forall i,j$ is indeed a cumulative distribution function. First, in the third step, I have established that $F_j(\underline{b})=0$. Second, $F_j(b)$ is an increasing function in b. At $\underline{b}$, $L_i(\underline{b})=H_i(b)$, for any $b>\underline{b}$, $L_i(\underline{b})<H_i(b)$; moreover, $\frac{\partial L_i(b)}{\partial b}>0$, $\frac{\partial L_i(\underline{b})}{\partial b}=0$ and $\frac{\partial H_i(b)}{\partial b}>0$, therefore, $\frac{\partial\left(L_i(b)-L_i(\underline{b})\right)}{\partial b}>\frac{\partial\left(L_i(b)-H_i(b)\right)}{\partial b}$. Third, $F_j(b)\leq 1\forall b\in S_i$. Finally, $F_j(b)$ is continuous in the support because $L_i(b)-L_i(\underline{b})$ and $L_i(b)-H_i(b)$ are continuous functions in the support.

Probability Distribution Function.

$$
\begin{aligned}
f_j(b) &= \frac{\partial F_j(b)}{\partial b}\\
&= \frac{min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}\underline{b}\left(min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right)}{b^2\left(min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right)^2}\\
&= \frac{min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}\underline{b}}{b^2\left(min\left\{\theta_i+\theta_j,\theta_i+T,k\right\}-max\left\{0,\theta_i-T,\theta_i+\theta_j-k\right\}\right)}\quad\forall i=n,s \qquad (6)
\end{aligned}
$$

Expected Equilibrium Bid.

$$
\begin{aligned}
E_j(b) &= \int_{\underline{b}}^{P} b f_j(b) \partial b \\
&= \int_{\underline{b}}^{P} \frac{b min\left\{\theta_i+\theta_j, \theta_i+T, k\right\} \underline{b}}{b^2\left(min\left\{\theta_i+\theta_j, \theta_i+T, k\right\}-max\left\{0, \theta_i-T, \theta_i+\theta_j-k\right\}\right)} \partial b \\
&\quad +P\left(1-F_j(P)\right) \\
&= \frac{min\left\{\theta_i+\theta_j, \theta_i+T, k\right\} \underline{b}}{min\left\{\theta_i+\theta_j, \theta_i+T, k\right\}-max\left\{0, \theta_i-T, \theta_i+\theta_j-k\right\}}[ln(b)]_{\underline{b}}^{P} \\
&\quad +P\left(1-F_j(P)\right) \quad \forall i=n, s
\end{aligned} \tag{7}
$$

where $(1-F_j(P))$ in equation 7 is the probability assigned by firm j to the maximum price allowed by the auctioneer.[15]

Expected Profit. The expected profit is defined by equation 4 and is equal to $\overline{\pi}_i = \underline{b} min\left\{\theta_i+\theta_j, \theta_i+T, k\right\}$.

In the rest of the proof, I will work out the *lower bound of the support*, the *cumulative distribution function*, the *probability distribution function*, the *expected equilibrium price* and the *expected profit* for the different possible realization of demands (θ_s, θ_n).

*Area A*1.

First, I work out the lower bound of the support on the border between areas $B1$ and $B2$, $\theta_s = k-T$. On the border, $\underline{b}_n$ solves $\underline{b}_n min\left\{\theta_n+\theta_s, \theta_n+T, k\right\} = Pmax\left\{0, \theta_n-T, \theta_s+\theta_n-k\right\}$, therefore $\underline{b}_n = \dfrac{P(\theta_n-T)}{k}$ and $\underline{b}_s$ solves $\underline{b}_s min\left\{\theta_n+\theta_s, \theta_s+T, k\right\} = Pmax\left\{0, \theta_s-T, \theta_s+\theta_n-k\right\}$, therefore $\underline{b}_s = \dfrac{P(\theta_n+\theta_s-k)}{\theta_s+T}$. Plugging the value of θ_s on the border between these areas into $\underline{b}_s$ formula, I obtain $\underline{b}_s = \dfrac{P(\theta_n+k-T-k)}{k-T+T} = \dfrac{P(\theta_n-T)}{k} = \underline{b}_n$. Therefore, on the border between these areas, $\underline{b}_s = \underline{b}_n = \dfrac{P(\theta_n-T)}{k}$.

In areas $A1$ and $B1$, $\underline{b}_n > \underline{b}_s$. In area $A1$, taking partial derivatives $\dfrac{\partial \underline{b}_n}{\partial \theta_s} = \dfrac{-P(\theta_n-T)}{(\theta_n+\theta_s)^2} < 0$ and $\dfrac{\partial \underline{b}_s}{\partial \theta_s} = \dfrac{P(k+T-\theta_n)}{(\theta_s+T)^2} > 0$. In area $B1$, taking partial derivatives $\dfrac{\partial \underline{b}_n}{\partial \theta_s} = 0$ and $\dfrac{\partial \underline{b}_s}{\partial \theta_s} = \dfrac{P(k+T-\theta_n)}{(\theta_s+T)^2} > 0$. Therefore, in areas $A1$ and $B1$, $\underline{b}_n > \underline{b}_s$. Hence, $S = \left[max\left\{\underline{b}_n, \underline{b}_s\right\}, P\right] = [\underline{b}_n, P]$. In particular, in area $A1$, $S = \left[\dfrac{P(\theta_n-T)}{(\theta_n+\theta_s)}, P\right]$ and

[15] When the transmission line is congested, the mixed strategy equilibrium is asymmetric. In such an equilibrium, the cumulative distribution function for the firm located in the low-demand market is continuous in the upper bound of the support. In contrast, the cumulative distribution function of the firm located in the high-demand region is discontinuous, which means that the firm located in the high-demand market submits the maximum bid allowed by the auctioneer with a positive probability $(1-F_j(P))$. Hence, in order to work out the expected value, in addition to the integral, it is necessary to add the term $P\left(1-F_j(P)\right)$. Figure 4 illustrates these characteristics.

in area $B1$, $S = \left[\frac{P(\theta_n - T)}{k}, P\right]$.

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \frac{\theta_n + \theta_s}{\theta_s + T}\frac{b - \underline{b}}{b} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \frac{\theta_s + T}{\theta_s + T}\frac{b - \underline{b}}{b} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned} F_s(P) &= \frac{\theta_n + \theta_s}{\theta_s + T}\frac{P - \frac{P(\theta_n - T)}{\theta_n + \theta_s}}{P} = 1 \\ F_n(P) &= \frac{\theta_s + T}{\theta_s + T}\frac{P - \frac{P(\theta_n - T)}{\theta_n + \theta_s}}{P} = \frac{(\theta_s + T)}{(\theta_n + \theta_s)} < 1 \end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned} f_s(b) &= \frac{\partial F_s(b)}{\partial b} = \frac{\theta_n + \theta_s}{\theta_s + T}\frac{\underline{b}}{b^2} \\ f_n(b) &= \frac{\partial F_n(b)}{\partial b} = \frac{\theta_s + T}{\theta_s + T}\frac{\underline{b}}{b^2} \end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned} E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} \frac{\theta_n + \theta_s}{\theta_s + T}\frac{\underline{b}}{b}\partial b = \frac{\theta_n + \theta_s}{\theta_s + T}\underline{b}\left[ln(b)\right]_{\underline{b}}^{P} \\ E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_n)\partial b = \int_{\underline{b}}^{P} \frac{\underline{b}}{b^2}\partial b = \frac{\theta_s + T}{\theta_s + T}\underline{b}\left[ln(b)\right]_{\underline{b}}^{P} + (1 - F_n(P))\,P \end{aligned}$$

Fifth, the expected profit is defined by equation 4 and is equal to $\overline{\pi}_n = \underline{b}(\theta_s + \theta_n)$ and $\overline{\pi}_s = \underline{b}(\theta_s + T)$.

Area $B1$.

First, the lower bound of the support is $S = \left[\frac{P(\theta_n - T)}{k}, P\right]$.

Second, I work out the cumulative distribution function.

$$F_s(b)=\begin{cases}0 & \text{if } b<\underline{b}\\ \dfrac{k}{T+k-\theta_n}\dfrac{b-\underline{b}}{b} & \text{if } b\in(\underline{b},P)\\ 1 & \text{if } b=P\end{cases}$$

$$F_n(b)=\begin{cases}0 & \text{if } b<\underline{b}\\ \dfrac{\theta_s+T}{T+k-\theta_n}\dfrac{b-\underline{b}}{b} & \text{if } b\in(\underline{b},P)\\ 1 & \text{if } b=P\end{cases}$$

Moreover,

$$\begin{aligned}F_s(P) &= \frac{k}{T+k-\theta_n}\frac{P-\dfrac{P(\theta_n-T)}{k}}{P}=1\\ F_n(P) &= \frac{\theta_s+T}{T+k-\theta_n}\frac{P-\dfrac{P(\theta_n-T)}{k}}{P}=\frac{\theta_s+T}{k}<1\end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned}f_s(b) &= \frac{\partial F_s(b)}{\partial b}=\frac{k}{T+k-\theta_n}\frac{\underline{b}}{b^2}\\ f_n(b) &= \frac{\partial F_n(b)}{\partial b}=\frac{\theta_s+T}{T+k-\theta_n}\frac{\underline{b}}{b^2}\end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned}E_s(b) &= \int_{\underline{b}}^{P} bf_s(b_s)\partial b=\int_{\underline{b}}^{P}\frac{k}{T+k-\theta_n}\frac{\underline{b}}{b}\partial b=\frac{k}{T+k-\theta_n}\underline{b}\left[ln(b)\right]_{\underline{b}}^{P}\\ E_n(b) &= \int_{\underline{b}}^{P} bf_n(b_n)\partial b=\int_{\underline{b}}^{P}\frac{\theta_s+T}{T+k-\theta_n}\frac{\underline{b}}{b}\partial b+\left(1-F_n(P)\right)P\\ &= \frac{\theta_s+T}{T+k-\theta_n}\underline{b}\left[ln(b)\right]_{\underline{b}}^{P}+\left(1-F_n(P)\right)P\end{aligned}$$

Fifth, the expected profit is defined by equation 4 and is equal to $\overline{\pi}_n=\underline{b}k$ and $\overline{\pi}_s=\underline{b}(\theta_s+T)$.

Area B2.

First, the lower bound of the support is $S=\left[max\left\{\underline{b}_n,\underline{b}_s\right\},P\right]=\left[\dfrac{P(\theta_s+\theta_n-k)}{k},P\right]$.

Second, I work out the cumulative distribution function.

$$F_i(b)=\begin{cases}0 & \text{if } b<\underline{b}\\ \dfrac{k}{2k-\theta_i-\theta_j}\dfrac{b-\underline{b}}{b} & \text{if } b\in(\underline{b},P)\quad \forall i=s,n\\ 1 & \text{if } b=P\end{cases}$$

Third, the probability distribution function is equal to:

$$f_i(b) = \frac{\partial F_i(b)}{\partial b} = \frac{k}{2k - \theta_i - \theta_j}\frac{\underline{b}}{b^2} \quad \forall i = s, n$$

Fourth, the expected bid is determined by:

$$E_i(b) = \int_{\underline{b}}^{P} b f_i(b_i)\partial b = \int_{\underline{b}}^{P} \frac{k}{2k - \theta_n - \theta_s}\frac{\underline{b}}{b}\partial b = \frac{k}{2k - \theta_n - \theta_s}\underline{b}\left[ln(b)\right]_{\underline{b}}^{P} \quad \forall i = s, n$$

Fifth, the expected profit is defined by equation 4 and is equal to $\overline{\pi}_n = \overline{\pi}_s = \underline{b}k$.

Proposition 2. The effect of an increase in transmission capacity.

Area A1.

$$\frac{\partial \underline{b}}{\partial T} = \frac{-P}{(\theta_s + \theta_n)} < 0$$

$$\frac{\partial F_n(P)}{\partial T} = \frac{1}{(\theta_s + \theta_n)} > 0$$

$$\begin{aligned} \frac{\partial E_n(b)}{\partial T} &= \frac{\partial \underline{b}}{\partial T}\left[ln\left(\frac{P}{\underline{b}}\right)\right] + \underline{b}\left[\frac{\underline{b}}{P}\frac{-\frac{\partial \underline{b}}{\partial T}P}{\underline{b}^2}\right] - \frac{\partial F_n(P)}{\partial T} \\ &= \frac{\partial \underline{b}}{\partial T}\left[ln\left(\frac{P}{\underline{b}}\right) - 1\right] - \frac{\partial F_n(P)}{\partial T} < 0 \Leftrightarrow ln\left(\frac{P}{\underline{b}}\right) > 1 \end{aligned}$$

$$\begin{aligned} \frac{\partial E_s(b)}{\partial T} &= \frac{\partial \underline{b}}{\partial T}\frac{\theta_s + \theta_n}{\theta_s + T}\left[ln\left(\frac{P}{\underline{b}}\right)\right] - \underline{b}\frac{\theta_s + \theta_n}{(\theta_s + T)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] + \underline{b}\frac{\theta_s + \theta_n}{\theta_s + T}\left[\frac{\underline{b}}{P}\frac{-\frac{\partial \underline{b}}{\partial T}P}{\underline{b}^2}\right] \\ &= \frac{\partial \underline{b}}{\partial T}\frac{\theta_s + \theta_n}{\theta_s + T}\left[ln\left(\frac{P}{\underline{b}}\right) - 1\right] - \underline{b}\frac{\theta_s + \theta_n}{(\theta_s + T)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] < 0 \Leftrightarrow ln\left(\frac{P}{\underline{b}}\right) > 1 \end{aligned}$$

$$\frac{\partial \overline{\pi}_n}{\partial T} = -P < 0$$

$$\frac{\partial \overline{\pi}_s}{\partial T} = \frac{-P}{(\theta_s + \theta_n)}(\theta_s + T) + \frac{P(\theta_n - T)}{(\theta_s + \theta_n)} = \frac{P(\theta_n - 2T - \theta_s)}{(\theta_s + \theta_n)} > 0 \Leftrightarrow \theta_n > 2T + \theta_s$$

Area B1.

$$\frac{\partial \underline{b}}{\partial T} = \frac{-P}{k} < 0$$

$$\frac{\partial F_n(P)}{\partial T} = \frac{1}{k} > 0$$

$$\begin{aligned}
\frac{\partial E_n(b)}{\partial T} &= \frac{\partial \underline{b}}{\partial T}\frac{\theta_s + T}{k + T - \theta_n}\left[ln\left(\frac{P}{\underline{b}}\right)\right] + \underline{b}\frac{k + T - \theta_n - \theta_s - T}{(k + T - \theta_n)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] \\
&\quad + \underline{b}\frac{\theta_s + T}{k + T - \theta_n}\left[\frac{\underline{b}}{P}\frac{-\frac{\partial \underline{b}}{\partial T}P}{\underline{b}^2}\right] - \frac{\partial F_n(P)}{\partial T} \\
&= \frac{\partial \underline{b}}{\partial T}\frac{\theta_s + T}{k + T - \theta_n}\left[ln\left(\frac{P}{\underline{b}}\right) - 1\right] + \underline{b}\frac{k - \theta_s - \theta_n}{(k + T - \theta_n)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] \\
&\quad - \frac{\partial F_n(P)}{\partial T} < 0 \Leftrightarrow ln\left(\frac{P}{\underline{b}}\right) > 1
\end{aligned}$$

$$\begin{aligned}
\frac{\partial E_s(b)}{\partial T} &= \frac{\partial \underline{b}}{\partial T}\frac{k}{k + T - \theta_n}\left[ln\left(\frac{P}{\underline{b}}\right)\right] - \underline{b}\frac{k}{(k + T - \theta_n)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] \\
&\quad + \underline{b}\frac{k}{k + T - \theta_n}\left[\frac{\underline{b}}{P}\frac{-\frac{\partial \underline{b}}{\partial T}P}{\underline{b}^2}\right] \\
&= \frac{\partial \underline{b}}{\partial T}\frac{k}{k + T - \theta_n}\left[ln\left(\frac{P}{\underline{b}}\right) - 1\right] \\
&\quad - \underline{b}\frac{k}{(k + T - \theta_n)^2}\left[ln\left(\frac{P}{\underline{b}}\right)\right] < 0 \Leftrightarrow ln\left(\frac{P}{\underline{b}}\right) > 1
\end{aligned}$$

$$\frac{\partial \overline{\pi}_n}{\partial T} = -P < 0$$

$$\frac{\partial \overline{\pi}_s}{\partial T} = \frac{-P}{k}(\theta_s + T) + \frac{P(\theta_n - T)}{k} = \frac{P(\theta_n - 2T - \theta_s)}{k} > 0 \Leftrightarrow \theta_n > 2T + \theta_s$$

Annex 2. The effect of transmission capacity constraints and transmission losses

Proposition 3. Characterization of the equilibrium in the presence of transmission constraints and transmission costs.

For further reference:

$$\begin{aligned} H_i(\theta, P, T, t) &= max\{0, \theta_i - T, \theta_j + \theta_i - k\} \\ Ht_i(\theta, P, T, t) &= max\{0, \theta_j - k\} \\ L_i(\theta, P, T, t) &= min\{\theta_i + \theta_j, \theta_i + T, k\} \\ Lt_i(\theta, P, T, t) &= max\{0, min\{\theta_i, T, k - \theta_i\}\} \end{aligned}$$

I proceed as in proposition one: first, I work out the general formulas of the *lower bound of the support*, the *cumulative distribution function*, the *probability distribution function*, the *expected equilibrium price* and the *expected profit*; second, I work out the particular formulas associated with each single area in figure 7.

Lower Bound of the Support. The lower bound of the support is defined according to lemma four.

Cumulative Distribution Function.

In the first step, the payoff function for any firm is:

$$\begin{aligned} \pi_i(b) &= F_j(b)\left[b\left(H_i(\theta, P, T, t)\right) - t\left(Ht_i(\theta, P, T, t)\right)\right] + \\ &\quad (1 - F_j(b))\left[b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right)\right] = \\ &= -F_j(b)\left[b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) - b\left(H_i(\theta, P, T, t)\right) + t\left(Ht_i(\theta, P, T, t)\right)\right] \\ &\quad b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) \end{aligned} \tag{8}$$

In the second step, $\pi_i(b) = \overline{\pi}_i \forall b \in S_i, i = n, s$, where S_i is the support of the mixed strategy. Then,

$$\begin{aligned} &= -F_j(b)\left[b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) - b\left(H_i(\theta, P, T, t)\right) + t\left(Ht_i(\theta, P, T, t)\right)\right] \\ &\quad b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) \Rightarrow \\ F_j(b) &= \frac{b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) - \overline{\pi}_i}{b\left[L_i(\theta, P, T, t) - H_i(\theta, P, T, t)\right] - t\left[Lt_i(\theta, P, T, t) - Ht_i(\theta, P, T, t)\right]} \end{aligned} \tag{9}$$

In the third step, at $\underline{b}$, $F_i(\underline{b}) = 0 \forall i = n, s$. Then,

$$\overline{\pi}_i = b\left(L_i(\theta, P, T, t)\right) - t\left(Lt_i(\theta, P, T, t)\right) \tag{10}$$

Fourth step, plugging 10 into 9, I obtain the mixed strategies for both firms.

$$\begin{aligned} F_j(b) &= \frac{(b - \underline{b})L_i(\theta, P, T, t)}{b\left[L_i(\theta, P, T, t) - H_i(\theta, P, T, t)\right] - t\left[Lt_i(\theta, P, T, t) - Ht_i(\theta, P, T, t)\right]} = \\ &\quad \forall i = n, s \end{aligned} \tag{11}$$

Probability Distribution Function.

$$\begin{aligned}
f_j(b) &= \frac{\partial F_j(b)}{\partial b} \\
&= \frac{L_i(\cdot)\left[\underline{b}\left[L_i(\theta,P,T,t)-H_i(\theta,P,T,t)\right]-t\left[Lt_i(\theta,P,T,t)-Ht_i(\theta,P,T,t)\right]\right]}{\left[b\left[L_i(\theta,P,T,t)-H_i(\theta,P,T,t)\right]-t\left[Lt_i(\theta,P,T,t)-Ht_i(\theta,P,T,t)\right]\right]^2} \\
&\quad \forall i = n,s \qquad (12)
\end{aligned}$$

For further reference:

$$\begin{aligned}
n(\cdot) &= L_i(\cdot)\left[\underline{b}\left[L_i(\theta,P,T,t)-H_i(\theta,P,T,t)\right]-t\left[Lt_i(\theta,P,T,t)-Ht_i(\theta,P,T,t)\right]\right] \\
d_1(\cdot) &= \left[L_i(\theta,P,T,t)-H_i(\theta,P,T,t)\right] \\
d_2(\cdot) &= \left[Lt_i(\theta,P,T,t)-Ht_i(\theta,P,T,t)\right]
\end{aligned}$$

Expected Equilibrium Bid.

$$\begin{aligned}
E_j(b) &= \int_{\underline{b}}^{P} b f_j(b)\partial b \\
&= \int_{\underline{b}}^{P} \frac{b\,(n(\cdot))}{\left[b\,(d_1(\cdot))-t\,(d_2(\cdot))\right]^2}\partial b + P(1-F_j(P)) \;\; \forall i = n,s
\end{aligned}$$

I solve this equation by substitution of variables. In particular:

$$\begin{aligned}
U &= \left[b\,(d_1(\cdot))-t\,(d_2(\cdot))\right] \Rightarrow b = \frac{U+t\,(d_2(\cdot))}{d_1(\cdot)} \\
\frac{\partial U}{\partial b} &= d_1 \Rightarrow \partial b = \frac{\partial U}{\partial d_1}
\end{aligned}$$

Therefore:

$$\begin{aligned}
E_j(b) &= \int_{\underline{b}}^{P} \frac{\left(\frac{U+t\,(d_2(\cdot))}{d_1(\cdot)}\right)n(\cdot)}{U^2}\frac{\partial U}{d_1(\cdot)} + P(1-F_j(P)) \\
&= \frac{n(\cdot)}{d_1(\cdot)}\left[\int_{\underline{b}}^{P}\frac{U\partial U}{U^2} + \int_{\underline{b}}^{P}\frac{t\,(d_2(\cdot))\,\partial U}{U^2}\right] + P(1-F_j(P)) \\
&= \frac{n(\cdot)}{d_1(\cdot)^2}\left[ln(U) - \frac{t\,(d_2(\cdot))}{U}\right]_{\underline{b}}^{P} + P(1-F_j(P))
\end{aligned}$$

Substituting again:

$$\begin{aligned}
E_j(b) &= \frac{n(\cdot)}{d_1(\cdot)^2} \\
&\quad \left[ln\left(\frac{P\,(d_1(\cdot))-t\,(d_2(\cdot))}{\underline{b}\,(d_1(\cdot))-t\,(d_2(\cdot))}\right) - \frac{t\,(d_2(\cdot))}{P\,(d_1(\cdot))-t\,(d_2(\cdot))} + \frac{t\,(d_2(\cdot))}{\underline{b}\,(d_1(\cdot))-t\,(d_2(\cdot))}\right] \\
&\quad +P(1-F_j(P)) \qquad (13)
\end{aligned}$$

In the rest of the proof, I will work out the *lower bound of the support*, the *cumulative distribution function*, the *probability distribution function*, the *expected equilibrium price* and the *expected profit* for the different possible realizations of demands (θ_s, θ_n) (figure 7).

Area A1.

First, the lower bound of the support is:

$$\begin{aligned} \underline{b}_n\theta_n + \underline{b}_n\theta_s - t\theta_s = P(\theta_n - T) \Rightarrow \underline{b}_n &= \frac{P(\theta_n - T) + t\theta_s}{\theta_n + \theta_s} \\ \underline{b}_s\theta_s + \underline{b}_sT - tT = 0 \Rightarrow \underline{b}_s &= \frac{tT}{\theta_s + T} \end{aligned}$$

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b - \underline{b})(\theta_n + \theta_s)}{b\left[(\theta_s + \theta_n) - (\theta_n - T)\right] - tmin\left\{\theta_s, k - \theta_n\right\}} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b - \underline{b})(\theta_s + T)}{b(\theta_s + T) - tT} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned} \text{If } \underline{b}_n \geq \underline{b}_s \Rightarrow F_s(P) &= 1 \\ F_n(P) &= \frac{(P(\theta_s + T) - t\theta_s)(\theta_s + T)}{(P(\theta_s + T) - tT)(\theta_s + \theta_n)} \\ \text{If } \underline{b}_n < \underline{b}_s \Rightarrow F_s(P) &= \frac{(P(\theta_s + T) - tT)(\theta_s + \theta_n)}{(P(\theta_s + T) - t\theta_s)(\theta_s + T)} \\ F_n(P) &= 1 \end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned} f_s(b) = \frac{\partial F_s(b)}{\partial b} &= \frac{(\theta_n + \theta_s)(\underline{b}(\theta_s + T) - t\theta_s)}{(b(\theta_s + T) - t\theta_s)^2} \\ f_n(b) = \frac{\partial F_n(b)}{\partial b} &= \frac{(\theta_s + T)(\underline{b}(\theta_s + T) - tT)}{(b(\theta_s + T) - tT)^2} \end{aligned}$$

Fourth, the expected bid is determined by:

$$
\begin{aligned}
E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{(\theta_n+\theta_s)(\underline{b}(\theta_s+T)-t\theta_s)}{(b(\theta_s+T)-t\theta_s)^2} + (1-F_s(P))P \\
&= \frac{(\theta_n+\theta_s)(\underline{b}(\theta_s+T)-t\theta_s)}{(\theta_s+T)^2} \\
&\quad \left[ln\left(\frac{P(\theta_s+T)-t\theta_s}{\underline{b}(\theta_s+T)-t\theta_s}\right) - \frac{t\theta_s}{P(\theta_s+T)-t\theta_s} + \frac{t\theta_s}{\underline{b}(\theta_s+T)-t\theta_s}\right] \\
&\quad +(1-F_s(P))P \\
E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{(\theta_s+T)(\underline{b}(\theta_s+T)-tT)}{(b(\theta_s+T)-tT)^2} + (1-F_n(P))P \\
&= \frac{(\underline{b}(\theta_s+T)-tT)}{(\theta_s+T)} \\
&\quad \left[ln\left(\frac{P(\theta_s+T)-tT}{\underline{b}(\theta_s+T)-tT}\right) - \frac{tT}{P(\theta_s+T)-tT} + \frac{tT}{\underline{b}(\theta_s+T)-tT}\right] \\
&\quad +(1-F_n(P))P
\end{aligned} \tag{14}
$$

In equation 14, I have solved by substituting variables:

$$
\begin{aligned}
U &= b(\theta_s+T)-t\theta_s \Rightarrow b = \frac{U+t\theta_s}{\theta_s+T} \\
\frac{\partial U}{\partial b} &= \theta_s+T \Rightarrow \partial b = \frac{\partial U}{\theta_s+T} \\
\text{and} & \\
U &= b(\theta_s+T)-tT \Rightarrow b = \frac{U+tT}{\theta_s+T} \\
\frac{\partial U}{\partial b} &= \theta_s+T \Rightarrow \partial b = \frac{\partial U}{\theta_s+T}
\end{aligned}
$$

Fifth, the expected profit is defined by equation 10 and is equal to $\overline{\pi}_n = \underline{b}(\theta_s+\theta_n)-t\theta_s$ and $\overline{\pi}_s = \underline{b}(\theta_s+T)-tT$.

Area B1a.

First, the lower bound of the support is:

$$
\begin{aligned}
\underline{b}_n\theta_n + \underline{b}_n(k-\theta_n) - t(k-\theta_n) = P(\theta_n-T) \Rightarrow \underline{b}_n &= \frac{P(\theta_n-T)+t(k-\theta_n)}{k} \\
\underline{b}_s\theta_s + \underline{b}_sT - tT = P(\theta_s+\theta_n-k) \Rightarrow \underline{b}_s &= \frac{P(\theta_s+\theta_n-k)+tT}{\theta_s+T}
\end{aligned}
$$

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})k}{b(k+T-\theta_n)-t(k-\theta_n)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})(\theta_s+T)}{b(k+T-\theta_n)-tT} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned}
\text{If } \underline{b}_n \geq \underline{b}_s \Rightarrow F_s(P) &= 1 \\
F_n(P) &= \frac{(P(k+T-\theta_n)-t(k-\theta_n))(\theta_s+T)}{(P(k+T-\theta_n)-tT)k} \\
\text{If } \underline{b}_n < \underline{b}_s \Rightarrow F_s(P) &= \frac{(P(k+T-\theta_n)-tT)k}{(P(k+T-\theta_n)-t(k-\theta_n))(\theta_s+T)} \\
F_n(P) &= 1
\end{aligned}$$

Third, the probability distribution function is equal to:

$$f_s(b) = \frac{\partial F_s(b)}{\partial b} = \frac{k(\underline{b}(k+T-\theta_n)-t(k-\theta_n))}{(b(k+T-\theta_n)-t(k-\theta_n))^2}$$
$$f_n(b) = \frac{\partial F_n(b)}{\partial b} = \frac{(\theta_s+T)(\underline{b}(\theta_s+T)-tT)}{(b(\theta_s+T)-tT)^2}$$

Fourth, the expected bid is determined by:

$$\begin{aligned}
E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{k(\underline{b}(k+T-\theta_n)-t(k-\theta_n))}{(b(k+T-\theta_n)-t(k-\theta_n))^2} + (1-F_s(P))P \\
&= \frac{k(\underline{b}(k+T-\theta_n)-t(k-\theta_n))}{(k+T-\theta_n)^2} \\
&\quad \left[ln\left(\frac{P(k+T-\theta_n)-t(k-\theta_n)}{\underline{b}(k+T-\theta_n)-t(k-\theta_n)}\right)\right] \\
&\quad \left[-\frac{t(k-\theta_n)}{P(k+T-\theta_n)-t(k-\theta_n)} + \frac{t(k-\theta_n)}{\underline{b}(k+T-\theta_n)-t(k-\theta_n)}\right] \\
&\quad +(1-F_s(P))P \\
E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{(\theta_s+T)(\underline{b}(k+T-\theta_n)-tT)}{(b(k+T-\theta_n)-tT)^2} + (1-F_n(P))P \\
&= \frac{(\theta_s+T)(\underline{b}(k+T-\theta_n)-tT)}{(k+T-\theta_n)^2} \\
&\quad \left[ln\left(\frac{P(k+T-\theta_n)-tT}{\underline{b}(k+T-\theta_n)-tT}\right) - \frac{tT}{P(k+T-\theta_n)-tT} + \frac{tT}{\underline{b}(k+T-\theta_n)-tT}\right] \\
&\quad +(1-F_n(P))P
\end{aligned} \tag{15}$$

In equations 15, I have solved by substituting variables:

$$\begin{aligned}
U &= b(k+T-\theta_n)-t(k-\theta_n) \Rightarrow b = \frac{U+t(k-\theta_n)}{k+T-\theta_n} \\
\frac{\partial U}{\partial b} &= k+T-\theta_n \Rightarrow \partial b = \frac{\partial U}{k+T-\theta_n} \\
\text{and} & \\
U &= b(k+T-\theta_n)-tT \Rightarrow b = \frac{U+tT}{k+T-\theta_n} \\
\frac{\partial U}{\partial b} &= k+T-\theta_n \Rightarrow \partial b = \frac{\partial U}{k+T-\theta_n}
\end{aligned}$$

Fifth, the expected profit is defined by equation 10 and is equal to $\overline{\pi}_n = \underline{b}k - t(k-\theta_n)$ and $\overline{\pi}_s = \underline{b}(\theta_s+T) - tT$.

Area B1b.

First, the lower bound of the support is:

$$\begin{aligned}
\underline{b}_n k = P(\theta_n - T) \Rightarrow \underline{b}_n &= \frac{P(\theta_n-T)}{k} \\
\underline{b}_s\theta_s + \underline{b}_s T - tT = P(\theta_s+\theta_n-k) - t(\theta_n-k) \Rightarrow \underline{b}_s &= \frac{P(\theta_s+\theta_n-k)+t(k+T-\theta_n)}{\theta_s+T}
\end{aligned}$$

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})k}{b(k+T-\theta_n)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})(\theta_s+T)}{b(k+T-\theta_n)-t(T+k-\theta_n)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned}
\text{If } \underline{b}_n \geq \underline{b}_s \Rightarrow F_s(P) &= 1 \\
F_n(P) &= \frac{P(k+T-\theta_n)(\theta_s+T)}{(P-t)(k+T-\theta_n)k} \\
\text{If } \underline{b}_n < \underline{b}_s \Rightarrow F_s(P) &= \frac{(P-t)(k+T-\theta_n)k}{P(k+T-\theta_n)(\theta_s+T)} \\
F_n(P) &= 1
\end{aligned}$$

Third, the probability distribution function is equal to:

$$f_s(b) = \frac{\partial F_s(b)}{\partial b} = \frac{\underline{b}k}{b^2(k+T-\theta_n)}$$
$$f_n(b) = \frac{\partial F_n(b)}{\partial b} = \frac{(\underline{b}-t)(\theta_s+T)}{(b-t)^2(k+T-\theta_n)}$$

Fourth, the expected bid is determined by:

$$\begin{aligned}
E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{\underline{b}k}{b^2(k+T-\theta_n)} + (1-F_s(P))P \\
&= \frac{\underline{b}k}{(k+T-\theta_n)}\left[ln\left(\frac{P}{\underline{b}}\right)\right] + (1-F_s(P))P \\
E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{(\underline{b}-t)(\theta_s+T)}{(b-t)^2(k+T-\theta_n)} + (1-F_n(P))P \\
&= \frac{(\underline{b}-t)(\theta_s+T)}{(k+T-\theta_n)}\left[ln\left(\frac{P-t}{\underline{b}-t}\right) - \frac{t}{P-t} + \frac{t}{\underline{b}-t}\right] + (1-F_n(P))P \qquad (16)
\end{aligned}$$

In equations 16, I have solved by substituting variables:

$$\begin{aligned}
U &= b - t \Rightarrow b = U + t \\
\frac{\partial U}{\partial b} &= 1 \Rightarrow \partial b = \partial U
\end{aligned}$$

Fifth, the expected profit is defined by equation 10 and is equal to $\overline{\pi}_n = \underline{b}k$ and $\overline{\pi}_s = \underline{b}(\theta_s + T) - tT$.

Area B2a.

First, the lower bound of the support is:

$$\begin{aligned}
\underline{b}_n\theta_n + \underline{b}_n(k-\theta_n) - t(k-\theta_n) = P(\theta_s+\theta_n-k) \Rightarrow \underline{b}_n &= \frac{P(\theta_s+\theta_n-k)+t(k-\theta_n)}{k} \\
\underline{b}_s\theta_s + \underline{b}_s(k-\theta_s) - t(k-\theta_s) = P(\theta_s+\theta_n-k) \Rightarrow \underline{b}_s &= \frac{P(\theta_s+\theta_n-k)+t(k-\theta_s)}{k}
\end{aligned}$$

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})k}{b(2k-\theta_n-\theta_s)-t(k-\theta_n)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$
$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b-\underline{b})k}{b(2k-\theta_n-\theta_s)-t(k-\theta_s)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned} F_s(P) &= \frac{P(2k-\theta_n-\theta_s)-t(k-\theta_s)}{P(2k-\theta_n-\theta_s)-t(k-\theta_n)} \\ F_n(P) &= 1 \end{aligned}$$

Third, the probability distribution is equal to:

$$\begin{aligned} f_s(b) = \frac{\partial F_s(b)}{\partial b} &= \frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_n))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_n))^2} \\ f_n(b) = \frac{\partial F_n(b)}{\partial b} &= \frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_s))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_s))^2} \end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned} E_s(b) &= \int_{\underline{b}}^{P} bf_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_n))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_n))^2} + (1-F_s(P))P \\ &= \frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_n))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_n))^2} \\ &\quad \left[ln\left(\frac{P(2k-\theta_n-\theta_s)-t(k-\theta_n)}{\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_n)}\right)\right] \\ &\quad \left[-\frac{t(k-\theta_n)}{P(k+T-\theta_n)-t(k-\theta_n)} + \frac{t(k-\theta_n)}{\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_n)}\right] \\ &\quad +(1-F_s(P))P \\ E_n(b) &= \int_{\underline{b}}^{P} bf_n(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_s))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_s))^2} + (1-F_n(P))P \\ &= \frac{k(\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_s))}{(b(2k-\theta_n-\theta_s)-t(k-\theta_s))^2} \\ &\quad \left[ln\left(\frac{P(2k-\theta_n-\theta_s)-t(k-\theta_s)}{\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_s)}\right)\right] \\ &\quad \left[-\frac{t(k-\theta_s)}{P(k+T-\theta_n)-t(k-\theta_s)} + \frac{t(k-\theta_s)}{\underline{b}(2k-\theta_n-\theta_s)-t(k-\theta_s)}\right] \\ &\quad +(1-F_n(P))P \end{aligned} \tag{17}$$

where in equation 17, I have solved by substituting variables:

$$\begin{aligned} U &= b(2k-\theta_n-\theta_s)-t(k-\theta_n) \Rightarrow b = \frac{U+t(k-\theta_n)}{2k-\theta_n-\theta_s} \\ \frac{\partial U}{\partial b} &= 2k-\theta_n-\theta_s \Rightarrow \partial b = \frac{\partial U}{2k-\theta_n-\theta_s} \\ &\text{and} \\ U &= b(2k-\theta_n-\theta_s)-t(k-\theta_s) \Rightarrow b = \frac{U+t(k-\theta_s)}{2k-\theta_n-\theta_s} \\ \frac{\partial U}{\partial b} &= 2k-\theta_n-\theta_s \Rightarrow \partial b = \frac{\partial U}{2k-\theta_n-\theta_s} \end{aligned}$$

Fifth, the expected profit is defined by equation 10 and is equal to $\overline{\pi}_n = \underline{b}k - t(k - \theta_n)$ and $\overline{\pi}_s = \underline{b}k - t(k - \theta_s)$.

Area B2b.

First, the lower bound of the support is:

$$\begin{aligned}
\underline{b}_n k = P(\theta_s + \theta_n - k) \Rightarrow \underline{b}_n &= \frac{P(\theta_s + \theta_n - k)}{k} \\
\underline{b}_s\theta_s + \underline{b}_s(k - \theta_s) - t(k - \theta_s) = & \\
P(\theta_s + \theta_n - k) - t(\theta_n - k) \Rightarrow \underline{b}_s &= \frac{P(\theta_s + \theta_n - k) + t(2k - \theta_n - \theta_s)}{k}
\end{aligned}$$

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b - \underline{b})k}{b(2k - \theta_n - \theta_s)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{(b - \underline{b})k}{(b - t)(2k - \theta_n - \theta_s)} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned}
F_s(P) &= \frac{P(2k - \theta_n - \theta_s) - t(2k - \theta_n - \theta_s)}{P(2k - \theta_n - \theta_s)} \\
F_n(P) &= 1
\end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned}
f_s(b) = \frac{\partial F_s(b)}{\partial b} &= \frac{\underline{b}k}{b^2(2k - \theta_n - \theta_s)} \\
f_n(b) = \frac{\partial F_n(b)}{\partial b} &= \frac{(\underline{b} - t)k}{(b - t)^2(2k - \theta_n - \theta_s)}
\end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned}
E_s(b) &= \int_{\underline{b}}^{P} bf_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{\underline{b}k}{b^2(2k - \theta_n - \theta_s)} + (1 - F_s(P))P \\
&= \frac{\underline{b}k}{(2k - \theta_n - \theta_s)}\left[ln\left(\frac{P}{\underline{b}}\right)\right] + (1 - F_s(P))P \\
E_n(b) &= \int_{\underline{b}}^{P} bf_n(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{(\underline{b} - t)k}{(b - t)^2(2k - \theta_n - \theta_s)} + (1 - F_n(P))P \\
&= \frac{(\underline{b} - t)k}{(2k - \theta_n - \theta_s)}\left[ln\left(\frac{P - t}{\underline{b} - t}\right) - \frac{t}{P - t} + \frac{t}{\underline{b} - t}\right] + (1 - F_n(P))P \qquad (18)
\end{aligned}$$

where in equations 18, I have solved by substituting variables:

$$
\begin{aligned}
U &= b - t \Rightarrow b = U + t \\
\frac{\partial U}{\partial b} &= 1 \Rightarrow \partial b = \partial U
\end{aligned}
$$

Fifth, the expected profit is defined by equation 10 and is equal to $\overline{\pi}_n = \underline{b}k$ and $\overline{\pi}_s = \underline{b}k - t(k - \theta_s)$.

Proposition 4. Effect of an increase in transmission capacity.

In the presence of transmission capacity constraints and transmission costs, the "size" and "cost" mechanisms determine the equilibrium. These two mechanisms work in opposite directions which has important implications for equilibrium outcome allocations. Hence, an increase in transmission capacity modifies the relevant model variables (lower bound of the support, expected bids and expected profits) in a non-monotonic pattern. Therefore, no clear conclusions can be obtained through the analysis of the partial derivatives.

In this section, I present the static comparative in order to illustrate the difficulties to obtain a formal analysis from the analytical solutions. I present the results for area $A1$, the analysis is the same for the rest of the areas.

Area $A1$.

$$
\begin{aligned}
\frac{\partial \underline{b}_n}{\partial T} &= \frac{-P}{(\theta_s + \theta_n)} < 0 \\
\frac{\partial \underline{b}_s}{\partial T} &= \frac{t(\theta_s + T) - tT}{(\theta_s + T)^2} = \frac{t\theta_s}{(\theta_s + T)^2} > 0
\end{aligned}
$$

$$
\begin{aligned}
\frac{\partial F_n(P)}{\partial T} &= \frac{(2P(\theta_s + T) - t\theta_s)\left((P(\theta_s + T) - tT)(\theta_n + \theta_s)\right)}{\left((P(\theta_s + T) - tT)(\theta_n + \theta_s)\right)^2} + \\
&\quad \frac{t(\theta_n + \theta_s)(P(\theta_s + T) - t\theta_s)(\theta_s + T)}{\left((P(\theta_s + T) - tT)(\theta_n + \theta_s)\right)^2} > 0
\end{aligned}
$$

$$
\begin{aligned}
\frac{\partial E_n(b)}{\partial T} \quad = \quad & \frac{\frac{\partial \underline{b}}{\partial T}(\theta_s+T)+(\underline{b}-t)(\theta_s+T)-\underline{b}(\theta_s+T)+tT}{(\theta_s+T)^2} \\
& \left[ln\left(\frac{P(\theta_s+T)-tT}{\underline{b}(\theta_s+T)-tT}\right)-\frac{tT}{P(\theta_s+T)-tT}+\frac{tT}{\underline{b}(\theta_s+T)-tT}\right]+ \\
& \frac{\underline{b}(\theta_s+T)-tT}{\theta_s+T} \\
& \left[\frac{\underline{b}(\theta_s+T)-tT}{P(\theta_s+T)-tT}\right] \\
& \left[\frac{(P-t)(\underline{b}(\theta_s+T)-tT)-\left(\frac{\partial \underline{b}}{\partial T}(\theta_s+T)+\underline{b}-t\right)(P(\theta_s+T)-tT)}{(\underline{b}(\theta_s+T)-tT)^2}\right]+ \\
& \frac{\underline{b}(\theta_s+T)-tT}{\theta_s+T}\left[-\frac{t(P(\theta_s+T)-tT)-(P-t)tT}{(P(\theta_s+T)-tT)^2}\right]+ \\
& \frac{\underline{b}(\theta_s+T)-tT}{\theta_s+T}\left[\frac{t(\underline{b}(\theta_s+T)-tT)-\left(\frac{\partial \underline{b}}{\partial T}(\theta_s+T)+\underline{b}-t\right)tT}{(\underline{b}(\theta_s+T)-tT)^2}\right]
\end{aligned}
$$

$$
\begin{aligned}
\frac{\partial E_s(b)}{\partial T} \quad = \quad & \frac{\frac{\partial \underline{b}}{\partial T}(\theta_s+T)^3(\theta_s+\theta_n)+\underline{b}(\theta_n+\theta_s)(\theta_s+T)^2-2(\theta_s+T)\left[(\theta_s+\theta_n)(\underline{b}(\theta_s+T)-t\theta_s)\right]}{(\theta_s+T)^4} \\
& \left[ln\left(\frac{P(\theta_s+T)-t\theta_s}{\underline{b}(\theta_s+T)-t\theta_s}\right)-\frac{t\theta_s}{P(\theta_s+T)-t\theta_s}+\frac{t\theta_s}{\underline{b}(\theta_s+T)-t\theta_s}\right]+ \\
& \frac{(\theta_n+\theta_s)(\underline{b}(\theta_s+T)-tT)}{(\theta_s+T)^2} \\
& \left[\frac{(\underline{b}(\theta_s+T)-t\theta_s)}{P(\theta_s+T)-t\theta_s}\right] \\
& \left[\frac{P(\underline{b}(\theta_s+T)-t\theta_s)-\left(\frac{\partial \underline{b}}{\partial T}(\theta_s+T)+\underline{b}\right)(P(\theta_s+T)-t\theta_s)}{(\underline{b}(\theta_s+T)-t\theta_s)^2}\right]+ \\
& \frac{(\theta_n+\theta_s)(\underline{b}(\theta_s+T)-t\theta_s)}{(\theta_s+T)^2}\left[-\frac{Pt\theta_s}{(P(\theta_s+T)-t\theta_s)^2}\right]+ \\
& \frac{(\theta_n+\theta_s)(\underline{b}(\theta_s+T)-t\theta_s)}{\theta_s+T}\left[\frac{-\underline{b}t\theta_s-\left(\frac{\partial \underline{b}}{\partial T}(\theta_s+T)t\theta_s\right)}{(\underline{b}(\theta_s+T)-t\theta_s)^2}\right]
\end{aligned}
$$

$$
\frac{\partial \pi_n}{\partial T} \quad = \quad -P<0
$$

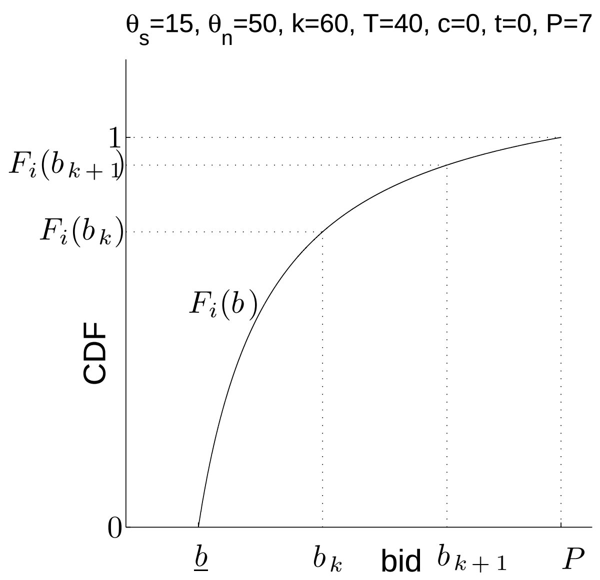
$$\begin{aligned}\frac{\partial \overline{\pi}_s}{\partial T} &= \frac{-P}{(\theta_s+\theta_n)}(\theta_s+T)+\frac{P(\theta_n-T)+t\theta_s}{(\theta_s+\theta_n)}-t \\ &= \frac{P(\theta_n-2T-\theta_s)-t\theta_n}{(\theta_s+\theta_n)}\end{aligned}$$

Annex 3. Expected equilibrium price: Simulation

Propositions one and three fully characterize the equilibrium. However, due to the complexity of calculations and to ensure that I did not make any algebra mistake, I work out the expected bid for both firms using the algorithm presented in this annex. The algorithm is based on the cumulative distribution function that is the mixed strategies equilibrium from which the rest of the variables of the model are derived.

As can be observed in tables 1 and 2, the differences between the expected bid using the analytical formulas from propositions one and three and using the algorithm proposed here are almost null.[16]

Figure 11: Expected bid. Simulation.



Algorithm: (figure 11)

1. I split the support of the mixed strategies equilibrium into K grid values (where K is a large number e.g., 5000 or 10000). I call each of these values $b_i(k)$ $\forall i = s, n$.

2. For each $b_i(k)$, I work out $F_i(b_i(k))$ using the formulas obtained in propositions one and three.

[16]I have applied this algorithm to work out the expected value for any realization of demand (all areas) and I have compared this with the analytical values and the results are almost identical.

3. The probability assigned to $p_i(b_i(k))$ equals the difference in the cumulative distribution function between two consecutive values $F_i(b_i(k+1)) - F_i(b_i(k))$. Therefore, $p(b_i(k)) = F_i(b_i(k+1)) - F_i(b_i(k))$. It is important to remark that one observation is lost during the process to work out the probabilities.

4. The expected value is the sum of each single bid multiplied by its probability: $E_i(b) = \sum_{k=0}^{K-1} b_i(k)p_i(b_i(k)) \ \forall i = s, n$

Annex 4. Characterization of the Nash Equilibrium when firms pay a point of connection tariff

In this paper, I assume that suppliers face transmission constraints and they are charged by a linear transmission tariff for the electricity sold in the other market. Under this assumption, I show that suppliers' strategies are affected by the "size" and the "cost" mechanisms that work in the opposite direction and determine equilibrium outcome allocations. However, when suppliers face transmission constraints and they are charged on basis of the total electricity that they inject in the grid (point of connection tariff), the suppliers pay the same transmission tariff for the electricity sold in their own market and the one sold in the other market. Therefore, the competitive advantage (cost effect) derived from the location in the high-demand market disappears and equilibrium market outcomes exclusively depend on the size effect. Moreover, given that electricity demand is very inelastic, an increase in generation costs is passed through to consumers that face an increase in equilibrium prices in both markets. This result is in line with the pass through literature (Marion and Muehlegger 2011; Fabra and Reguant 2014). Hence, a change in the design of transmission tariffs from the one used in the majority of the countries to the one proposed in this article could induce a large improvement in consumer welfare.

The general formulas of the *lower bound of the support*, the *cumulative distribution function*, the *probability distribution function*, the *expected equilibrium price* and the *expected profit* can be worked out using the same approach as that in annexes one and two. In this annex, I only work out the particular formulas associated with each single area (figure 3). Once that I characterize the equilibrium, I analyze the effect of an increase in transmission capacity on the main variables of the model. Finally, I compare the equilibrium outcome of the three model specifications: transmission constraints and *zero* transmission costs (model I); transmission constraints and *positive* transmission cost for the electricity sold in the other market (model II) and finally transmission constraints and *positive* transmission cost for the entire generation capacity (model III).

Area $A1$.

First, I work out the lower bound of the support. Using the same approach as in annex one, it is straightforward to show that in areas $A1$ and $B1$, $\underline{b}_n > \underline{b}_s$. Hence, $S = [max\{\underline{b}_n, \underline{b}_s\}, P] = [\underline{b}_n, P]$. Therefore, it is enough to work out $\underline{b}_n$. $\underline{b}_n$ can be derived from the next equation $(\underline{b}_n - t)(\theta_n + \theta_s) = (P - t)(\theta_n - T)$. Therefore, in area $A1$, $S = \left[t + \dfrac{(P-t)(\theta_n - T)}{(\theta_n + \theta_s)}, P\right]$.

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{\theta_n + \theta_s}{\theta_s + T}\dfrac{b - \underline{b}}{b - t} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{\theta_s + T}{\theta_s + T}\dfrac{b - \underline{b}}{b - t} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned} F_s(P) &= \frac{\theta_n + \theta_s}{\theta_s + T}\frac{P - t - \dfrac{(P-t)(\theta_n - T)}{\theta_n + \theta_s}}{P - t} = 1 \\ F_n(P) &= \frac{\theta_s + T}{\theta_s + T}\frac{P - t - \dfrac{P - t(\theta_n - T)}{\theta_n + \theta_s}}{P - t} = \frac{(\theta_s + T)}{(\theta_n + \theta_s)} < 1 \end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned} f_s(b) &= \frac{\partial F_s(b)}{\partial b} = \frac{\theta_n + \theta_s}{\theta_s + T}\frac{\underline{b} - t}{(b-t)^2} \\ f_n(b) &= \frac{\partial F_n(b)}{\partial b} = \frac{\theta_s + T}{\theta_s + T}\frac{\underline{b} - t}{(b-t)^2} \end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned} E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{\theta_n + \theta_s}{\theta_s + T}\frac{(\underline{b} - t)}{(b-t)^2}\partial b = \\ &\quad \frac{\theta_n + \theta_s}{\theta_s + T}(\underline{b} - t)\left[ln\left(\frac{P - t}{\underline{b} - t}\right) - \frac{t}{P - t} + \frac{t}{\underline{b} - t}\right] \\ E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_n)\partial b = \int_{\underline{b}}^{P} b\frac{\underline{b} - t}{(b-t)^2}\partial b + (1 - F_n(P))\,P = \\ &\quad (\underline{b} - t)\left[ln\left(\frac{P - t}{\underline{b} - t}\right) - \frac{t}{P - t} + \frac{t}{\underline{b} - t}\right] + (1 - F_n(P))\,P \end{aligned} \tag{19}$$

In equation 19, I have solved by substituting variables:

$$\begin{aligned} U &= b - t \Rightarrow b = U + t \\ \frac{\partial U}{\partial b} &= 1 \Rightarrow \partial b = \partial U \end{aligned}$$

Fifth, the expected profit is defined by $\overline{\pi}_n = (\underline{b} - t)(\theta_s + \theta_n)$ and $\overline{\pi}_s = (\underline{b} - t)(\theta_s + T)$.

*Area B*1.

First, the lower bound of the support is $S = \left[t + \frac{(P-t)(\theta_n - T)}{k}, P\right]$.

Second, I work out the cumulative distribution function.

$$F_s(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \frac{k}{T+k-\theta_n}\frac{b-\underline{b}}{b-t} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

$$F_n(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \frac{\theta_s + T}{T+k-\theta_n}\frac{b-\underline{b}}{b-t} & \text{if } b \in (\underline{b}, P) \\ 1 & \text{if } b = P \end{cases}$$

Moreover,

$$\begin{aligned} F_s(P) &= \frac{k}{T+k-\theta_n}\frac{(P-t) - \frac{(P-t)(\theta_n - T)}{k}}{P-t} = 1 \\ F_n(P) &= \frac{\theta_s + T}{T+k-\theta_n}\frac{(P-t) - \frac{(P-t)(\theta_n - T)}{k}}{P-t} = \frac{\theta_s + T}{k} < 1 \end{aligned}$$

Third, the probability distribution function is equal to:

$$\begin{aligned} f_s(b) &= \frac{\partial F_s(b)}{\partial b} = \frac{k}{T+k-\theta_n}\frac{\underline{b}-t}{(b-t)^2} \\ f_n(b) &= \frac{\partial F_n(b)}{\partial b} = \frac{\theta_s + T}{T+k-\theta_n}\frac{\underline{b}-t}{(b-t)^2} \end{aligned}$$

Fourth, the expected bid is determined by:

$$\begin{aligned} E_s(b) &= \int_{\underline{b}}^{P} b f_s(b_s)\partial b = \int_{\underline{b}}^{P} b\frac{k}{T+k-\theta_n}\frac{\underline{b}-t}{(b-t)^2}\partial b = \\ & \frac{k}{T+k-\theta_n}(\underline{b}-t)\left[ln\left(\frac{P-t}{\underline{b}-t}\right) - \frac{t}{P-t} + \frac{t}{\underline{b}-t}\right] \\ E_n(b) &= \int_{\underline{b}}^{P} b f_n(b_n)\partial b = \int_{\underline{b}}^{P} b\frac{\theta_s + T}{T+k-\theta_n}\frac{\underline{b}-t}{(b-t)^2}\partial b + (1 - F_n(P))\,P \\ &= \frac{\theta_s + T}{T+k-\theta_n}(\underline{b}-t)\left[ln\left(\frac{P-t}{\underline{b}-t}\right) - \frac{t}{P-t} + \frac{t}{\underline{b}-t}\right] + (1 - F_n(P))\,P \quad (20) \end{aligned}$$

In equation 20, I have solved by substituting the variables:

$$\begin{aligned} U &= b - t \Rightarrow b = U + t \\ \frac{\partial U}{\partial b} &= 1 \Rightarrow \partial b = \partial U \end{aligned}$$

Table 4: Effect of transmission constraint and transmission costs on equilibrium outcome ($\theta_s = 5$, $\theta_n = 55$, $k = 60$, $c = 0$, $P = 7$)

	T	$\underline{b}$	$\overline{\pi}_n$	$\overline{\pi}_s$	$\overline{\pi}$	$E_n(b)$	$E_s(b)$	$\theta_n E_n(b) + \theta_s E_s(b)$
Model I	40	1.75	105	184	289	4.2	3.2	247
Model II	40	1.87	105	24	129	3.1	3.3	187
Model III	40	2.87	82.5	62	144.5	4.8	4	284

Fifth, the expected profit is defined by $\overline{\pi}_n = (\underline{b} - t)k$ and $\overline{\pi}_s = (\underline{b} - t)(\theta_s + T)$.

Area B2.

First, the lower bound of the support is $S = [max\{\underline{b}_n, \underline{b}_s\}, P] = \left[t + \dfrac{(P-t)(\theta_s + \theta_n - k)}{k}, P\right]$.

Second, I work out the cumulative distribution function.

$$F_i(b) = \begin{cases} 0 & \text{if } b < \underline{b} \\ \dfrac{k}{2k - \theta_i - \theta_j} \dfrac{b - \underline{b}}{b - t} & \text{if } b \in (\underline{b}, P) \quad \forall i = s, n \\ 1 & \text{if } b = P \end{cases}$$

Third, the probability distribution function is equal to:

$$f_i(b) = \frac{\partial F_i(b)}{\partial b} = \frac{k}{2k - \theta_i - \theta_j} \frac{\underline{b} - t}{(b - t)^2} \quad \forall i = s, n$$

Fourth, the expected bid is determined by:

$$\begin{aligned} E_i(b) &= \int_{\underline{b}}^{P} b f_i(b_i) \partial b = \int_{\underline{b}}^{P} b \frac{k}{2k - \theta_n - \theta_s} \frac{\underline{b} - t}{(b - t)^2} \partial b = \\ & \frac{k}{2k - \theta_n - \theta_s} (\underline{b} - t) \left[ln\left(\frac{P - t}{\underline{b} - t}\right) - \frac{t}{P - t} + \frac{t}{\underline{b} - t}\right] + (1 - F_n(P))\, P \end{aligned} \quad (21)$$

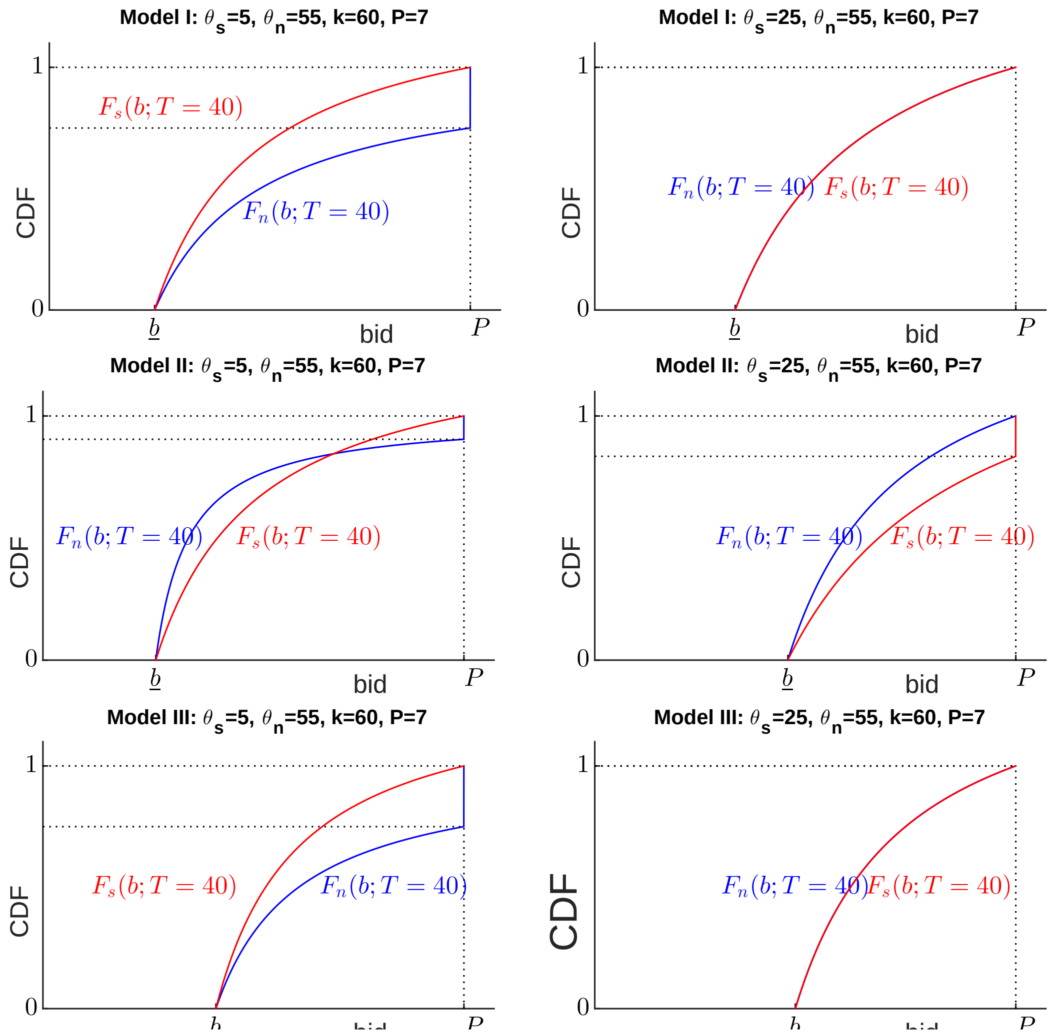
In equation 21, I have solved by substituting variables:

$$\begin{aligned} U &= b - t \Rightarrow b = U + t \\ \frac{\partial U}{\partial b} &= 1 \Rightarrow \partial b = \partial U \end{aligned}$$

Fifth, the expected profit is defined by $\overline{\pi}_n = \overline{\pi}_s = (\underline{b} - t)k$.

It is straightforward to show that an increase in transmission capacity induces the same changes in equilibrium outcome as when the transmission costs are *zero* (proposition two).

Figure 12: Cumulative Distribution Functions of models I, II and III.



Model comparison

In the last part of the annex, I compare the equilibrium outcome of the three different model specifications: transmission constraints and *zero* transmission costs (model I); transmission constraints and *positive* transmission costs for the electricity sold in the other market (model II) and, finally, transmission constraints and *positive* transmission costs for the entire generation capacity (model III).

The tree different model specifications affect suppliers' strategies in very different ways as can be observed in figure 12. The diversity of strategies induces important changes on the most relevant variables of the model (table 4).

I have discussed the three models in detail in section four (pages. 17-18). I refer the reader to those pages to follow the analysis.

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Welfare effects of unbundling under different regulatory regimes in natural gas markets

António Brandão* Joana Pinho† Joana Resende‡ Paula Sarmento§

Isabel Soares¶

November 2015

Abstract

In this paper, we develop a theoretical model that enriches the literature on the pros and cons of ownership unbundling vis-à-vis lighter unbundling frameworks in the natural gas markets. For each regulatory framework, we compute equilibrium outcomes when an incumbent firm and a new entrant compete *à la* Cournot in the final gas market. We find that the entrant's contracting conditions in the upstream market and the transmission tariff are key determinants of the market structure in the downstream gas market (both with ownership and with legal unbundling). We also study how the regulator must optimally set transmission tariffs in each of the two unbundling regimes. We conclude that welfare maximizing tariffs often require free access to the transmission network (in both regulatoy regimes). However, when the regulator aims at promoting the break-even of the regulated transmission system operator, the first-best tariff is unfeasible in both regimes. Hence, we study a more realistic set-up, in which the regulator's action is constrained by the break-even of regulated firm (the transmission system operator). In this set-up, we find that, for a given transmission tariff, final prices in the downstream market are always higher with ownership unbundling than with legal unbundling.

Keywords: Ownership unbundling; Legal unbundling; Access price regulation; Natural gas market; Transmission tariffs.

JEL Codes: L50, L43, L95.

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*Cef.up, University of Porto. E-mail: abrandao@fep.up.pt

†Cef.up, University of Porto. E-mail: jpinho@fep.up.pt. Joana Pinho acknowledges financial support from Cef.up, Fundação para a Ciência e Tecnologia and FEDER (SFRH/BPD/79535/2011).

‡Cef.up, University of Porto. E-mail: jresende@fep.up.pt. Joana Resende acknowledges financial support from Cef.up and FCT.

§Cef.up, University of Porto. E-mail: sarmento@fep.up.pt

¶Cef.up, University of Porto. E-mail: isoares@fep.up.pt

1 Introduction

In the last decade, natural gas markets in Europe have experienced an intense liberalization process (Directive 2003/55/EC). Cavaliere (2007) argues that this process aimed at, among other aspects, breaking the vertical integration in gas markets, and unbundling the competitive activities (production, imports, wholesale and retail sale of gas) from those segments of the gas chain characterized by a natural or *de facto* monopoly (transmission[1], storage and distribution networks).[2]

This paper enriches the literature addressing the pros and cons of ownership unbundling[3] vis-à-vis lighter unbundling frameworks (namely the legal unbundling[4]). This constitutes a controversial issue among energy specialists[5] (see, for instance, Ascari, 2011; Stronzik, 2012; Growitsch and Stronzik, 2014 and the references therein). In practice, some European countries have adopted the strictest unbundling regime (e.g. UK or Portugal have imposed ownership unbundling), while other countries have lighter unbundling rules (e.g. France or Germany).[6]

There is a vast literature on the issues of foreclosure in vertical markets (see, for example, Rey and Tirole, 2007, for a detailed survey) and regulation and liberalization of network utilities (see, for example, Newbery, 2000). Economic theory reports ambiguous conclusions regarding the effects of complete unbundling on welfare (see Laffont and Tirole, 2003; Hoffler and Kranz, 2011, for example). Our paper adds to this literature by developing an analytical model that explicitly addresses some specific features of natural gas markets.

In the recent years, several European countries have adopted regulatory policies with the objective

[1] Note that gas transportation is often subject to strong economies of scale. This is explained by: *(i)* the huge costs associated with investments in transmission infrastructure; and (ii) technical factors like the pipeline diameter or resource indivisibility. For an evaluation of the impact of regulation on the investment in the gas transmission and distribution in the EU, see Soares and Magalhães (2012).

[2] According to Cavaliere (2007), other important aspects of the liberalization process are, for instance, the promotion of third party access to essential facilities (including transmission networks); and the reduction of consumers' swithching costs when they want to change gas supplier.

[3] Growitsch and Stronzik (2014) refer that ownership unbundling is *"the strictest regulatory regime of vertical disintegration, the company that owns and operates the transmission assets is fully separated from the rest of the system, meaning that it does not participate in further business activities in retail or production and import"*.

[4] In the case of legal unbundling, gas transportation and gas supply are assured by legally separated entities but they may be part of the same economic corporation. As a result, when legal unblunding is allowed, the natural gas markets tend to reflect an historically developed structure with a national (or sub-national) transport operating system, which often dominates natural gas supply in the downstream market (see Cavaliere, 2007).

[5] For example, Lowe *et al.* (2007).refer that: *"at a time when very large investments are needed to promote market integration and ensure security of supply, the way the current unbundling is set up, leads to worrying distortions of investment incentives. In many Member States it is currently le[t] to the vertically integrated incumbents to invest in the additional transmission capacity that could bring more competition to their own supply business: such a setting is unlikely to yield socially optimal investment decisions. There is little doubt that a coordinated European response is required."* (p. 24)

[6] Growitsch and Stronzik (2014) refer that France has a lighter unbundling framework (in comparison with ownership unbundling). Some other countries had chosen not to completely separate transmission from other activities in the natural gas chain, as it is the case of USA, where legal unbundling is frequently found (Ascari, 2011; Growitsch and Stronzik, 2014).

of fostering competition in natural gas markets, namely by encouraging the entry of new firms in the downstream market (e.g., gas release programmes, capacity investment promotion, price-cap and revenue cap regulation). Since the transmission infrastructure constitutes an essential input to supply gas to final consumers, the regulatory options concerning transmission activities necessarily affect the market structure in the downstream natural gas market. This paper addresses this problem in the context of price regulation of the transmission activities. More precisely, we consider that the regulator unilaterally chooses the transmission tariff that natural gas suppliers pay to the transmission system operator (TSO), as it is the case, for example, in the Portuguese market.

In this paper, we intend to investigate how the equilibrium market structure in the downstream market may be affected by the access conditions to the transmission network. We shed some light on optimal regulatory policy regarding third party access to the transmission network by characterizing the transmission tariff under two alternative regulatory objectives (overall welfare maximization *versus* break-even of the TSO). Our baseline model addresses a market with ownership unbundling, corresponding to the strictest unbundling criteria in the European Union. Then, we study equilibrium outcomes arising in markets with lighter regulatory frameworks (namely, legal unbundling).

Relying on game theoretical tools, we propose a stylized model of entry in a natural gas market. In the model with ownership unbundling, we assume competition *à la* Cournot in the downstream market, allowing for (possibly) asymmetric marginal costs (due to firms' asymmetric conditions regarding the acquisition price of natural gas). In order to be active in the downstream market, both firms need to have access to the gas transmission network of an independent firm. The network access price is endogenous to the model, being fully controlled by the regulator. In the model of legal unbundling, we assume that the incumbent supplier in the downstream market is legally independent from the TSO but they are part of the same economic group.[7] In particular, this opens the door to the adoption of coordinated strategies envisaging the maximization of the joint profits of the integrated corporation.

In the model with ownership unbundling, we find that the first-best transmission tariff (that maximizes overall welfare) requires free access to the transmission network.[8] This result follows from the regulator's attempt to eliminate competition distortions due to double marginalization issues (which would prevent an efficient operation of the natural gas system). However, this always leads to

[7] The legal unbundling framework often relies on the Independent Transmission Operator (ITO), in which the TSO may *"remain part of a vertically integrated undertaking. However, numerous detailed rules are provided in order to ensure effective unbundling. The ITO has to be autonomous. In Article 17(1) Electricity and Gas Directives it is made clear that the ITO must be equipped with all financial, technical, physical and human resources necessary to fulfil its obligations and to carry out the activity of electricity or gas transmission."* For more detailed information, please see European Commission (2010).

[8] This reflects a policy of "pricing at the margin", as we assume that all the transmission system are fixed, yielding zero marginal cost. In a model with positive and constant marginal transmission costs, our results would remain qualitatively valid but our first-best results concerning t would have to reinterpreted as a mark-up over marginal cost.

negative profits in the transmission activity, due to the fixed costs incurred to build and maintain the transmission pipelines. Hence, in a more realistic set-up, in which the regulator aims at guaranteeing the TSO's break-even, it sets a positive (second-best) tariff. As a result, entry of a new competitor may become more difficult, specially when fixed costs are high or natural gas price in the foreign upstream market is excessively high (vis-à-vis the natural gas contracting price of the incumbent natural gas supplier).

The first-best transmission tariff is also zero in the model with legal unbundling. In the case of second-best regulation, we find that, for a given tariff, gas quantities in the final market are greater with legal unbundling than with ownership unbundling. Accordingly, final prices tend to be lower with legal unbundling, in line with the empirical predictions by Growitsch and Stronzik (2014) who find that *"ownership unbundling has no impact on natural gas end-user prices, while the more modest legal unbundling reduces them significantly"*. Moreover, with second-best transmission regulation, overall welfare with ownership unbundling is expected to be lower than overall welfare with legal unbundling since gas quantities (price) in the final market are larger (lower) in legal than in ownership unbundling (in particular, transmission tariffs are expected to be lower in the first case).

The rest of the paper is organized as follows. Section 2 presents a brief overview of the literature studying regulation of natural gas transmission. Section 3 analyzes the baseline model with ownership unbundling, obtaining the optimal transmission tariff under the objectives of (i) overall welfare maximization and (ii) break-even of the TSO. Section 4 briefly solves the model with legal unbundling. Section 5 compares overall welfare with ownership and legal unbundling. Finally, Section 5 concludes and identifies some lines for future research.

2 Literature Overview

This paper contributes to the recent literature on transmission regulation in natural gas markets. The theoretical works that study regulation in gas markets usually consider the two following regulatory instruments: gas release[9] and capacity investment[10] (Cremer and Laffont, 2002; Cremer *et al.,* 2003; Gasmi *et al.,* 2004; Gasmi and Oviedo, 2005, 2010; Clastres and David, 2009; and Chaton *et al.,* 2012). These works usually concentrate in each regulatory instrument separately. Chaton *et al.* (2012) are

[9] Gas release programs require the dominant firm to sell a fraction of its supply in order to guarantee that there is effective competition in the market. The implementation of these programs is limited in time. They only help competitors in expecting development of hubs or new investments in import infrastructures. Gas release programs were firstly applied in 1992 in UK and, more recently, in Spain, Italy, Germany, Austria and France. For example, in Spain the law requires each firm to supply less than 70% of total demand.

[10] By regulating the market through capacity investment, the regulator creates incentives to the investment in pipelines to promote imports.

an exception, by considering the possibility of combining the two policy strategies.

Several works have analyzed the strategic interaction between transmission networks (midstream) and downstream distribution markets. Most of this literature takes as exogenous the capacity of the transmission network and the charge applied for its use (e.g., De Vany and Walls, 1999; and Doane and Spulber, 1994). Dorigoni *et al.* (2010) address the impact of imports of natural gas. Doane *et al.* (2008) analyze the issue of concentration on secondary markets for natural gas transmission. However, differently from this paper, the previous works do not aim at explicitly studying the effects of welfare maximizing regulatory policies concerning transmission tariff schemes, which are a common regulatory practice (e.g. in the Portuguese case).

To the best of our knowledge, only a few theoretical works have dealt with the issue of upstream-downstream strategic effects entailed by transmission rates. Gasmi and Oviedo (2010) analyze how the type of strategic interaction in the downstream market (Cournot, Stackelberg and no competition) influence capacity transmission prices. Gasmi *et al.* (2004) investigate alternative regulatory policies with the objective of dampening the effects of gas suppliers' market power. Cavaliere (2007) describes how an incumbent firm may restrict imports' competitive pressure, and studies regulation based on gas release programs. Chaton *et al.* (2012) study to which extent gas release and transmission capacity investment may constitute instruments to promote competition in natural gas markets. Finally, Brandão *et al.* (2014) compare two mechanisms of transmission tariff (Postage Stamp and Entry-Exit Systems) with respect to their impacts on welfare. However, none of these papers deal with the issue of access pricing under ownership versus legal unbundling.

The industry structure considered in the theoretical model of Chaton *et al.* (2012) shares some similarities with our framework. They also study competition between an incumbent firm and a marketer (corresponding to the entrant, in our model) in the final market. Like in our model, the incumbent is a potential gas supplier of the marketer. However, the differences between the two works are evident. Firstly, in the model of Chaton *et al.* (2012), the entrant could buy gas both from the incumbent and a foreign supplier, even if the prices are different; while, in our model, the entrant optimally buys gas from the most competitive supplier (whose gas is cheaper). Secondly, the transmission access charge is assumed to be exogenous in the model of Chaton *et al.* (2012); while we endogenize the transmission tariff chosen by the regulator, comparing two unbundling regimes.

Accordingly, we also contribute to the debate around the pros and cons of ownership unbundling. The standard arguments regarding ownership unbundling stress that, on the one hand, it might prevent discrimination between affiliate firms and independent firms and avoid foreclosure, but, on the other hand, it may also lead to a loss of economies of scope and to lower efficiency, due to higher transaction costs.[11] It may also lead to problems of forestalled investment (raising supply security issues). Hoffler and Kranz (2011) theoretically demonstrate that legal unbundling leads to higher output than other degrees of unbundling. More recently, Growitsch and Stronzik (2014) empirically analyze the effects of ownership unbundling of gas transmission networks. Using data from 18 European countries the authors conclude that *"ownership unbundling has no impact on natural gas end-user prices, while the more modest legal unbundling reduces them significantly"*. With a more institutional perspective, also Glanchard *et al.* (2014) and Bouzarovski *et al.* (2015) analyze the transmission networks. In particular Glanchard *et al.* (2014) conclude that the precise architecture of gas transmission networks is related with the market arrangement choices, and mention that for simple transmission networks, vertical integration can be the most efficient system.

3 Ownership unbundling

Consider a natural gas market in which an incumbent firm and a new entrant may supply natural gas to final consumers. The incumbent firm is denoted by i, whereas the new entrant is denoted by e. In the final (downstream market), firms sell homogeneous goods, making strategic quantity decisions. Let p denote the price of the gas in the downstream market, which is a linear function of total quantity. More precisely, $p = a - q_i - q_e$, where $a > 0$ is a parameter capturing the economic dimension of the downstream natural gas market; q_i is the quantity sold by the incumbent firm and q_e is the quantity sold by the entrant.

The incumbent firm imports natural gas at a price equal to $p_g > 0$.[12] The price p_g is exogenous and it corresponds to the full price of gas at the entry of the national transmission system. We assume it is set under long-term contracts (e.g., "take or pay" contracts). We also assume that the amount of natural gas acquired by firm i under such contracts is sufficient to match demand in the downstream natural gas market, meaning that firm i has no incentives to import natural gas at the price p_e.[13] Differently, the entrant (who is new in the market) either buys the natural gas in the foreign market

[11] Howell *et al.* (2010) emphasize the role of transaction costs in the context of electricity markets (costs of frequent transactions, costs associated with the restriction of contractual incompleteness and costs associated with bounded rationality). The authors refer that *"Now, where it has been permitted to, vertical integration is rapidly re-emerging", as a response to transaction costs.* According to the authors, the contracting failures arising in a regime of ownership unbundling *"have manifested themselves into poor wholesale price and quantity risk management, problems of adverse selection and strategic bargaining in the presence of asymmetric information and market power, forestalled investment (undermining security supply)"*. Although Howell *et al.* (2010) specifically address the electricity and the telecommunication sectors, their arguments regarding transaction costs apply as well to the natural gas markets, where asymmetric information issues and hold-up problems are very relevant.

[12] If firm i was able to produce natural gas, this assumption could be easily adapted by considering that firm i's marginal production cost is given by $c = p_g$.

[13] Implicitly, for the sake of simplicity, we are ruling out storage issues. The analysis of the dynamic aspects behind storage decisions is beyond the scope of our static model and it constitutes an interesting topic for future research.

at price p_e[14]; or it buys gas from the incumbent firm, at price p_i.[15] On the top of acquisition costs (which may be different for the two firms), we assume that firms may have additional distribution and marketing costs related to their retailing activities (e.g. invoicing, marketing, customer relationship management, among others). More precisely, we consider that both firms have a retailing marginal cost equal to $c \geq 0$. Our baseline model addresses a market with ownership unbundling between the firms supplying natural gas in the downstream market and the transmission system operator (TSO). In this set-up, only the gas transmission is regulated, with the regulator choosing the tariff t that the TSO charges to the incumbent and to the entrant. For simplicity, we normalize the TSO marginal costs to zero, so that the the TSO only has a fixed cost $F > 0$ that can be interpreted as the (initial) cost of installing the gas pipelines.

Figure 1 depicts market participants (and their relationship) in the baseline model with ownership unbundling (i.e. full vertical separation between gas supply and gas transmission).

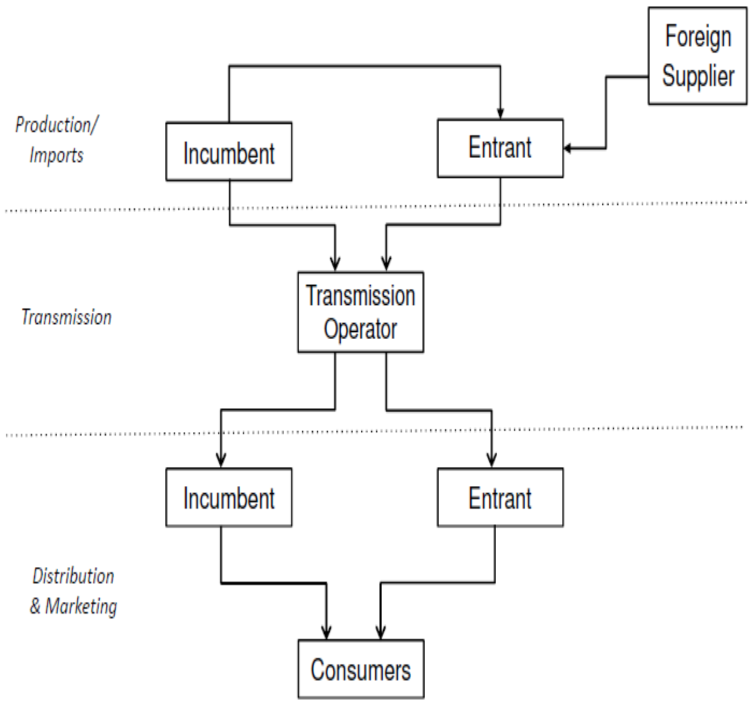

Fig.1: Ownership unbundling framework

To guarantee that the downstream market is economically viable when the incumbent firm is the only natural gas supplier, we impose the following assumption:

[14]The price p_e could either be the natural gas spot price or the price fixed in long term contracts at the moment of entry. Analogously to p_g, we assume p_e is the full price at the entry of the national transmission system (meaning that it includes all the transportation costs incurred before the gas enters the national system) Clearly, in the particular case $p_e = p_g$, the contracting conditions would be the same for both firms.

[15]This possibility was also considered in as in Chaton *et al.* (2012). The qualitative nature of the results (concerning the comparison of the two unbundling regimes) would remain unchanged if we ruled out this possibility.

Assumption 1. $a - p_g - c > t$ If Assumption 1 was not satisfied, the reservation price a would be lower than the full additive marginal cost of the incumbent firm $(p_g + c + t)$ and, therefore, the incumbent would never be interested in being active in the downstream market (regardless of p_e).

The timing of the game is the following:

1. The gas spot price, p_e, is formed in the foreign market and the regulator decides t.
2. The incumbent firm chooses the unit gas price to charge to the entrant, p_i.
3. The entrant decides whether to buy the gas from the incumbent firm (at price p_i) or to import the gas (at price p_e).
4. Incumbent and entrant simultaneously choose quantities, q_i and q_e, to supply in the downstream market.

First, we analyze the optimal value of t when the objective of the regulator is to maximize the overall social welfare, defined by the sum of the consumer surplus and the profits of the firms participating in the national gas system (first-best transmission tariff). Afterwards, in Section *2.4* we consider a more realistic set-up, assuming that the regulator's behavior is constrained by the need to guarantee the break-even of the firms developing regulated activities (i.e. the TSO).

Given the sequential structure of the game, we search for the subgame perfect Nash equilibrium, relying on backward induction techniques.

3.1 Downstream market

In the downstream market, we must distinguish between the case in which the entrant buys the gas from the incumbent firm and the case in which the entrant imports it. We start by considering the case first case. In what follows, we define $\mu \equiv a - p_g - c$, $\mu > 0$.

The profit function of the incumbent firm is:

$$\begin{aligned}\pi_{i,d}(q_i, q_e, p_i, t) &= (a - q_i - q_e)q_i + p_i q_e - p_g(q_i + q_e) - cq_i - tq_i \\ &= (\mu - t - q_i - q_e)q_i + (p_i - p_g)q_e\end{aligned}$$

while the profit function of the entrant is:

$$\begin{aligned}\pi_{e,d}(q_i, q_e, p_i, t) &= (a - q_i - q_e)q_e - p_i q_e - cq_e - tq_e \\ &= (\mu + p_g - p_i - t - q_i - q_e)q_e.\end{aligned}$$

Note that the profit functions, $\pi_{i,d}(q_i, q_e, p_i, t)$ and $\pi_{e,d}(q_i, q_e, p_i, t)$, are strictly concave in q_i and q_e, respectively. Accordingly, in an interior solution with both firms active in the market, the optimal output levels solve the following the system of first-order conditions (FOC), for given p_i and t :

$$\begin{cases} \frac{d\pi^s_{i,d}}{dq_i} = 0 \\ \\ \frac{d\pi^s_{e,d}}{dq_e} = 0 \end{cases} \Leftrightarrow \begin{cases} -2q_i - q_e + \mu - t = 0 \\ \\ p_g - p_i - q_i - 2q_e + \mu - t = 0 \end{cases} \Leftrightarrow \begin{cases} q_{i,d}(p_i, t) = \frac{p_i - p_g + \mu - t}{3} \\ \\ q_{e,d}(p_i, t) = \frac{2p_g - 2p_i + \mu - t}{3} \end{cases}$$

Both firms are active in the market iff:

$$q_{i,d}(p_i, t) > 0 \;\Leftrightarrow\; p_i > p_g - \mu + t$$
$$q_{e,d}(p_i, t) > 0 \;\Leftrightarrow\; p_i < p_g + \frac{\mu - t}{2}$$

Note that $q_{i,d}(p_i, t) \geq q_{e,d}(p_i, t)$, provided that $p_i \geq p_g$. This is an expected result since we have Cournot competition in the downstream market with asymmetric costs and, for $p_i > p_g$, the incumbent firm is more efficient than the entrant (the opposite would occur when $p_i < p_g$).

Under Assumption 1, if $p_i \leq p_g - \mu + t$, the entrant is monopolist in the downstream market and produces the quantity that maximizes:

$$\pi_{e,d}(q_e, p_i, t) = (\mu + p_g - p_i - t - q_e)q_e.$$

As this function is concave, the maximum is the solution of the FOC:

$$q_{e,d}(p_i, t) = \frac{\mu + p_g - t - p_i}{2}.$$

In this case, the incumbent firm is only active in the upstream market (as the entrant's supplier) and its profit is equal to:

$$\pi_{i,d}(p_i, t) = (p_i - p_g)q_{e,d}(p_i, t) = \frac{(p_i - p_g)(\mu + p_g - t - p_i)}{2}$$

If $p_i \geq p_g + \frac{\mu - t}{2}$, then the incumbent is monopolist in the downstream market (provided the entrant does not import gas, a possibility we will study later on in the paper). In this case, $q_e = 0$ and the incumbent behaves as a monopolist. It produces an output level equal to $\frac{\mu - t}{2}$, and it obtains a profit equal to $\frac{(\mu - t)^2}{4}$.

Summing up, the profit of the incumbent firm, given p_i , is:

$$\pi_{i,d}(p_i,t)=\begin{cases}\frac{(p_i-p_g)(\mu+p_g-t-p_i)}{2} & if \quad 0<p_i\le p_g-\mu+t\\ \frac{-5p_i^2+5p_i(2p_g-t+\mu)-5p_g(p_g-t+\mu)+(t-\mu)^2}{9} & if \quad p_g-\mu+t<p_i<p_g+\frac{\mu-t}{2}\\ \frac{(\mu-t)^2}{4} & if \quad p_i\ge p_g+\frac{\mu-t}{2}\end{cases} \tag{1}$$

It follows immediately that, in the second-stage of the game, the incumbent will never choose $0 < p_i \le p_g - \mu + t$, since such a price will make the entrant much more efficient than itself (and, therefore, excludes the incumbent from the downstream market). Moreover, from Assumption 1, the incumbent would be selling natural gas to the entrant at loss in this price domain. More precisely, since $\mu > t$, for $p_i \le p_g - \mu + t$, the incumbent would be fixing a price p_i below its marginal acquisition price p_g. Thus, the incumbent would be making losses in the upstream market and no profits in the downstream market.

The profit of the entrant is:

$$\pi_{e,d}(p_i,t)=\begin{cases}\frac{(\mu+p_g-t-p_i)^2}{4} & if \quad 0<p_i\le p_g-\mu+t\\ \frac{(2p_g-2p_i+\mu-t)^2}{9} & if \quad p_g-\mu+t<p_i<p_g+\frac{\mu-t}{2}\\ 0 & if \quad p_i\ge p_g+\frac{\mu-t}{2}\end{cases} \tag{2}$$

The quantities produced by the two firms are:

$$\Big(q_{i,d}(p_i,t),q_{m,d}(p_i,t)\Big)=\begin{cases}\left(0,\frac{\mu+p_g-t-p_i}{2}\right) & if \quad 0<p_i\le p_g-\mu+t\\ \left(\frac{p_i-p_g+\mu-t}{3},\frac{2p_g-2p_i+\mu-t}{3}\right) & if \quad p_g-\mu+t<p_i<p_g+\frac{\mu-t}{2}\\ \left(\frac{\mu-t}{2},0\right) & if \quad p_i\ge p_g+\frac{\mu-t}{2}\end{cases}. \tag{3}$$

Let us now analyze equilibrium outcomes in the downstream market if the entrant directly imports natural gas, instead of buying it from the incumbent firm. In this case, the profit function of the incumbent firm is:

$$\pi_{i,f}(q_i,q_e,t) \;=\; (a-q_i-q_e)q_i-p_gq_i-cq_i-tq_i \;=\; (\mu-t-q_i-q_e)q_i$$

and the profit function of the entrant is:

$$\pi_{e,f}(q_i,q_e,t)=(a-q_i-q_e)q_e-p_eq_e-cq_e-tq_e=(\mu+p_g-p_e-t-q_i-q_e)q_e$$

Solving the corresponding FOCs, we now obtain equilibrium output levels equal to:

$$\begin{cases} \frac{d\pi_{i,f}}{dq_i} = 0 \\ \\ \frac{d\pi_{e,f}}{dq_e} = 0 \end{cases} \Leftrightarrow \begin{cases} -2q_i - q_e + \mu - t = 0 \\ \\ p_g - p_e - q_i - 2q_e + \mu - t = 0 \end{cases} \Leftrightarrow \begin{cases} q_{i,f}(t) = \frac{p_e - p_g + \mu - t}{3} \\ \\ q_{e,f}(t) = \frac{2p_g - 2p_e + \mu - t}{3} \end{cases},$$

since the second-order conditions (SOC) are trivially satisfied.

Notice that the incumbent firm is active in the downstream market iff:

$$p_e - p_g > t - \mu$$

Under Assumption 1, we know that the RHS of the last inequality is negative. Thus, if $p_e > p_g$, the condition above is surely satisfied. Otherwise, the condition may or may not hold.

Similarly, it follows that the entrant is active in the downstream market iff:

$$p_e < p_g + \frac{\mu - t}{2}.$$

Hence, under Assumption 1, we have that both firms are active in the market iff:

$$p_g - \mu + t < p_e < p_g + \frac{\mu - t}{2}.$$

If this condition holds, the profits of the two firms are:

$$\pi_{i,f}(t) = \frac{(p_g - p_e - \mu + t)^2}{9} \quad \text{and} \quad \pi_{e,f}(t) = \frac{(2p_g - 2p_e + \mu - t)^2}{9}$$

If, instead, $p_e \le p_g - \mu + t$, the entrant is alone in the downstream market. Thus, the profits are:

$$\pi_{i,f}(t) = 0 \quad \text{and} \quad \pi_{e,f}(t) = \frac{(p_g - p_e + \mu - t)^2}{4}.$$

Finally, if $p_e \ge p_g - \frac{t}{2} + \frac{\mu}{2}$, the incumbent firm is monopolist and profits are:

$$\pi_{i,f}(t) = \frac{(\mu - t)^2}{4} \quad \text{and} \quad \pi_{e,f}(t) = 0.$$

In sum:

$$\pi_{i,f}(t) = \begin{cases} 0 & if \quad 0 < p_e \le p_g - \mu + t \\ \\ \frac{(p_g - p_e - \mu + t)^2}{9} & if \quad p_g - \mu + t < p_e < p_g + \frac{\mu - t}{2} \\ \\ \frac{(\mu - t)^2}{4} & if \quad p_e \ge p_g + \frac{\mu - t}{2} \end{cases}$$

and:

$$\pi_{e,f}(t) = \begin{cases} \frac{(p_g - p_e + \mu - t)^2}{4} & if \quad 0 \leq p_e \leq p_g - \mu + t \\ \frac{(2p_g - 2p_e + \mu - t)^2}{9} & if \quad p_g - \mu + t < p_e < p_g + \frac{\mu - t}{2} \\ 0 & if \quad p_e \geq p_g + \frac{\mu - t}{2} \end{cases} \tag{4}$$

The quantities produced by the two firms are:

$$\Big(q_{i,f}(t), q_{m,f}(t)\Big) = \begin{cases} \Big(0, \frac{p_g - p_e + \mu - t}{2}\Big) & if \quad 0 < p_e \leq p_g - \mu + t \\ \Big(\frac{p_e - p_g + \mu - t}{3}, \frac{2p_g - 2p_e + \mu - t}{3}\Big) & if \quad p_g - \mu + t < p_e < p_g + \frac{\mu - t}{2} \\ \big(\frac{\mu - t}{2}, 0\big) & if \quad p_e \geq p_g + \frac{\mu - t}{2} \end{cases} \tag{5}$$

3.2 Entrant's decision regarding its supplier

The entrant is still not locked-in to long term contracts. Hence, it is free to choose from which supplier to buy the gas. The entrant will anticipate market outcomes in the downstream market, comparing profits (2) and (4). In advance, it is not obvious that, when the price of the gas is lower in the foreign market than in the domestic market, the entrant surely prefers to buy in the foreign market (where the gas is cheaper). This occurs because the entrant is aware that the firm supplying the gas in the domestic market is also a competitor in the downstream market. Thus, it could be the case that, even paying a higher price to the incumbent firm (than in case of importing the gas), the entrant would be willing to acquire the gas from the incumbent firm, in order to soften competition in the downstream market. However, in our set-up without capacity constraints, that will not be the case. Indeed, the competitiveness of the incumbent firm in the downstream market is independent of whether or not it is the supplier of the entrant. To see this, note that if we replace $p_i = p_e$ in the output quantities sold by the incumbent firm in the domestic firm when it supplies the entrant (given in (3)) and when the entrant imports the gas (given in (5), we conclude that $q_{i,d}(t) = q_{i,f}(t)$, for all t.

The following Proposition sums up our main results for this stage of the model. The Proof is omitted since it is quite straightforward, resulting from the direct comparison between (2) and (4).

Proposition 1 *Given p_e, p_i and t:*

1. If $p_e \leq p_g + \frac{\mu - t}{2}$, the entrant is active in the downstream market and buys the gas from the supplier that sets the lowest price (i.e., it imports the gas iff $p_i \geq p_e$[16]).

2. If $p_e > p_g + \frac{\mu - t}{2}$, the entrant is only active in the market iff $p_i < p_g + \frac{\mu - t}{2}$. In this case, it buys the

[16] *We are assuming that, if the prices in the foreign and in the domestic markets are equal, the entrant buys all the gas from the incumbent firm.*

gas from the incumbent firm.

As expected, Proposition 1 highlights that the entrant firm tries to be as much efficient as possible by choosing the supplier that quotes the lowest gas price in the upstream market.

3.3 Incumbent's decision regarding p_i

If the incumbent chooses p_i such that $p_i \leq p_g - \mu + t$, it will make losses in the transmission activity (it would be selling the gas below its acquisition price p_g) and it will make no profits in the downstream market. Thus, in this case, the incumbent would always set $p_i > p_e$. As long as $0 \leq p_e \leq p_g - \mu + t$, the entrant will be the only firm in the downstream market.

When $p_e > p_g - \mu + t$, the incumbent is always active in the downstream market. Then, it chooses the price p_i that maximizes its overall profit. Using (1) and solving the corresponding FOC for this domain of parameters, we obtain:

$$\frac{\partial \pi_{i,d}(p_i,t)}{\partial p_i} = 0 \Leftrightarrow \frac{5}{9}\left[-2p_i + 2p_g - t + \mu\right] = 0 \Leftrightarrow p_i = p_g + \frac{\mu - t}{2}.$$

Thus, if there was no foreign supplier, the incumbent firm would set the price for the gas that evicted the entrant (i.e., such that $q_{e,d} = 0$). However, when deciding p_i, the incumbent is aware that the entrant has the alternative of directly importing the gas at price p_e. Notice that, for $p_g - \mu + t < p_i < p_g + \frac{\mu - t}{2}$, we have that $\frac{\partial \pi_{i,d}(p_i,t)}{\partial p_i} > 0$, which means that the incumbent wants to set a value for p_i as high as possible. As a result, if the incumbent is willing to sell the gas to the entrant, it will set:

$$p_i(t) = \begin{cases} p_e & if \quad p_g < p_e < p_g + \frac{\mu - t}{2} \\ p_g + \frac{\mu - t}{2} & if \quad p_e \geq p_g + \frac{\mu - t}{2} \end{cases}$$

The entrant firm is only be active if $p_e < p_g + \frac{\mu - t}{2}$. When $p_e \geq p_g + \frac{\mu - t}{2}$, buying natural gas abroad is not an economically viable alternative (it is too expensive) and therefore the incumbent firm forecloses the market.

To conclude this analysis, we have now to determine under which conditions the incumbent firm is willing to supply the entrant. First, note that if $p_e < p_g + \frac{\mu - t}{2}$, we have $p_i = p_e$ and the quantities sold by the two firms in the downstream market are the same regardless of whether the entrant buys the gas in the domestic market or in the foreign market, i.e., $q_{i,d}(p_e,t) = q_{i,f}(p_e,t) \equiv q_i(p_e,t)$ and $q_{e,d}(p_e,t) = q_{e,f}(p_e,t) \equiv q_e(p_e,t)$. Thus, the profit of the incumbent firm if it sells gas to the entrant can be written as:

$$\pi_{i,d}(p_e,t) = [\mu - t - q_i(p_e,t) - q_i(p_e,t)]\, q_i(p_e,t) + (p_e - p_g)q_e(p_e,t)$$

$$= \pi_{i,f}(p_e,t) + (p_e - p_g)q_e(p_e,t),$$

where $\pi_{i,f}(p_e,t)$ is the profit of the incumbent firm if it does not sell any gas to the entrant firm. Clearly, the incumbent firm is willing to supply the gas to the entrant iff:

$$\pi_{i,d}(p_e,t) \geq \pi_{i,f}(p_e,t) \;\Leftrightarrow\; p_e \geq p_g.$$

If $p_e < p_g$, the incumbent firm is unwilling to supply the entrant, since it will make losses in the upstream market without any compensation in the downstream market (since $p_i = p_e$, the decision to sell natural gas to the entrant firm would not affect its optimal quantity decision in the final market). Thus, the incumbent firm rationally prefers to avoid the upstream losses and leave the foreign firm to supply the entrant.

Second, if $p_e \geq p_g + \frac{\mu - t}{2}$, the incumbent firm will strategically charge the price that blocks the entry of the new competitor. Under this condition, the natural gas in the foreign market is not an affordable alternative and the incumbent firm takes the advantage of this fact to foreclose the market. When $p_g < p_e < p_g + \frac{\mu-t}{2}$, the incumbent sells gas to the entrant at price p_e. The following Lemma sums up these results. Again the proof is straightforward and therefore omitted.

Lemma 2 *Given the price of the gas in the foreign market, p_e and t:*

1. *If $p_e < p_g$, the incumbent firm is not willing to sell the gas to the entrant.*[17]
2. *If $p_g \leq p_e \leq p_g + \frac{\mu-t}{2}$, the incumbent firm sells natural gas to the entrant at a price equal to spot price in the foreign market, i.e., $p_i(t) = p_e$.*
3. *If $p_e > p_g + \frac{\mu-t}{2}$, the incumbent firm sets the price that blocks entry, $p_i(t) = p_g + \frac{\mu-t}{2}$.*

Notice that when $p_e < p_g$, we must distinguish two possible scenarios in the downstream market. If $p_e < p_g - \mu + t$, the entrant acquires the gas at a much lower price than the incumbent firm and, therefore, it is monopolist in the final market. If, instead, $p_g - \mu + t < p_e < p_g$, the entrant still buys

[17] *Alternatively, we could say that the incumbent firm will charge a price higher than p_e, making the entrant unwilling to buy the gas from the incumbent.*

the gas at a price lower than the one faced by the incumbent firm but the cost asymmetry is not enough to drive the incumbent firm out of the final market.

Figure 2 summarizes equilibrium outcomes for different domains of p_e :

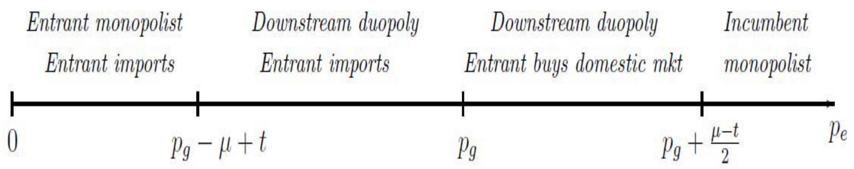

Fig. 2: Characterization of equilibrium outcomes, given t

In sum, when the entrant optimally chooses its gas supplier, its profit, for given t,[18] is:

$$\pi_e(t) = \begin{cases} \frac{(p_g - p_e + \mu - t)^2}{4} & if \quad 0 \leq p_e < p_g - \mu + t \\ \frac{(2p_g - 2p_e + \mu - t)^2}{9} & if \quad p_g - \mu + t < p_e \leq p_g + \frac{\mu - t}{2} \\ 0 & if \quad p_e > p_g + \frac{\mu - t}{2} \end{cases} .$$

Regarding the incumbent firm:

$$\pi_i(t) = \begin{cases} 0 & if \quad 0 \leq p_e < p_g - \mu + t \\ \frac{(p_g - p_e - \mu + t)^2}{9} & if \quad p_g - \mu + t < p_e < p_g \\ \frac{-5p_e^2 + 5p_e(2p_g + \mu - t) - 5p_g(p_g + \mu - t) + (\mu - t)^2}{9} & if \quad p_g \leq p_e \leq p_g + \frac{\mu - t}{2} \\ \frac{(\mu - t)^2}{4} & if \quad p_e > p_g + \frac{\mu - t}{2} \end{cases}$$

Hence, given t, the quantities produced by the incumbent firm and the entrant are:

$$\Big(q_i(t), q_e(t)\Big) = \begin{cases} \left(0, \frac{p_g - p_e + \mu - t}{2}\right) & if \quad 0 \leq p_e < p_g - \mu + t \\ \left(\frac{p_e - p_g + \mu - t}{3}, \frac{2p_g - 2p_e + \mu - t}{3}\right) & if \quad p_g - \mu + t < p_e \leq p_g + \frac{\mu - t}{2} \\ \left(\frac{\mu - t}{2}, 0\right) & if \quad p_e > p_g + \frac{\mu - t}{2} \end{cases} \tag{6}$$

[18]To obtain, the expression for profits, we must also take into consideration that $p_i = p_e$ when $p_g \leq p_e \leq p_g + \frac{\mu - t}{2}$.

The corresponding consumer surplus is:

$$CS(t) = \frac{[q_i(t)+q_e(t)]^2}{2} = \begin{cases} \frac{(p_g-p_e-t+\mu)^2}{8} & if \quad 0 \leq p_e < p_g-\mu+t \\ \frac{(-p_e+p_g-2t+2\mu)^2}{18} & if \quad p_g-\mu+t < p_e \leq p_g+\frac{\mu-t}{2} \\ \frac{(\mu-t)^2}{8} & if \quad p_e > p_g+\frac{\mu-t}{2} \end{cases}$$

3.4 Transmission tariff: first-best results

As we have concluded in Lemma 2, the price charged by the foreign supplier plays a crucial role in the determination of the market structure of the natural gas downstream market. However, to some extent, the domestic regulator may also affect the downstream market structure, by strategically choosing t. In this section, we investigate the optimal transmission tariff set by a regulator whose objective consists in maximizing total surplus, denoted by W, without any constraints. This is a preliminary analysis that will be developed in the next sub-section, in which we will consider that the regulator is required to promote the financial viability of the TSO.

In the first-best solution, the general problem faced by the regulator can be written as follows:

$$\max_t W(t),$$

where W corresponds to the sum of the consumers' surplus (CS), the profits of the natural gas suppliers (i.e., the incumbent firm and the entrant, $\pi_i + \pi_e$) and also the profit of the TSO (π_T), with the latter being equal to:

$$\pi_T(t) = t\,[q_i(t)+q_e(t)] - F.$$

Notice that the TSO does not play strategically. Instead, it simply takes its costs and price as given and ensures the transmission of all gas units that the incumbent and the entrant want to supply in the downstream market.

Proposition 3 *If the regulator is not restricted by the economic viability of the transmission operator,* *it sets a null transmission tariff, i.e.,* $t^* = 0$ *and the overall welfare is equal to:*

$$W^* = \begin{cases} \frac{3}{8}(p_g - p_e + \mu)^2 - F & if \quad 0 \leq p_e \leq p_g - \mu \\ \frac{11(p_g - p_e)^2 + 8\mu(p_g - p_e + \mu)}{18} - F & if \quad p_g - \mu < p_e < p_g \\ \frac{(2\mu - p_e + p_g)(4\mu + p_e - p_g)}{18} - F & if \quad p_g \leq p_e < p_g + \frac{\mu}{2} \\ \frac{3}{8}\mu^2 - F & if \quad p_e \geq p_g + \frac{\mu}{2} \end{cases} \tag{7}$$

Proof. See the Appendix. ■

The key rationale behind the previous result is the following:. when the regulator does not ensure the economic viability of the transmission system operator, it will choose the lowest possible transmission tariff, $t^* = 0$. Not surprisingly, when $t^* = 0$, we get the largest possible output level in the final market. The natural gas price is the final market is also set at the lowest possible level since firms do not pass-through any transmission costs to consumers when $t^* = 0$ (firms compete *à la* Cournot).

However, under first-best regulation, the maximum total surplus is achieved at the cost of economic losses in the transmission activity since the TSO is unable to recover its fixed cost F when $t^* = 0$. Thus, this first-best outcome may not be achievable. The following subsection analyzes equilibrium outcomes in a more realistic set-up when the regulator's welfare maximization objective is constrained by the requirement of assuring the break-even of the regulated firm (i.e. the TSO).

3.5 Transmission tariff: second-best results

Until now, we have considered regulation schemes that do not take into account issues related to the recovery of the costs of the TSO. However, in practice, energy regulators often take into consideration the constraints associated with the break even of regulated firms.[19]

When $t^* = 0$, the economic viability of the TSO is a key issue, since the TSO's profit is equal to $-F$. One way to overcome this situation could be the attribution of a lump sum subsidy to the TSO (in the amount of F). However, this raises the issue of defining who should contribute to pay such a subsidy. In this context, the practice of energy regulators in Europe tends to favor the definition of second-best tariffs, corresponding to the maximization of overall welfare provided that the regulated activities do not lead to economic losses.

Suppose now that the regulator must ensure the economic viability of the operator of transmission

[19] This is, for example, the case of the Portuguese regulator, Entidade Reguladora dos Serviços Energéticos (ERSE), which aims to *"ensure the existence of conditions which allow, for the regulated activities, the obtaining of an economic and financial balance"*. See ERSE website: http://www.erse.pt/eng/naturalgas/codes/Paginas/default.aspx. Access date: 26th September 2013.

system. More precisely, the tariff t must maximize overall welfare subject to the constraint $\Pi \geq 0$. For simplicity, we set $\Pi = 0$.

Recall that overall welfare is decreasing with t in all branches. As a result, in the second-best results, for a given p_e, the regulator must choose the lowest transmission tariff t^s that ensures $\pi_T(t^s) = 0$. In order to guarantee the economic viability of the TSO, we impose the following Assumption, that follows from conditions (9), (11) and (12), below.

Assumption 2. *The amount of fixed costs is low enough to guarantee that transmission is an economically viable activity, regardless of the market structure in the downstream market, with*

$$F \leq \min \left\{ \frac{(\mu + p_g - p_e)^2}{8}, \frac{(p_g - p_e + 2\mu)^2}{24}, \frac{\mu^2}{8} \right\}.$$

When $0 \leq p_e \leq p_g - \mu + t$, the incumbent firm is surely evicted from the market. Thus, ensuring the economic viability of the TSO requires:

$$t \times \frac{p_g - p_e - t + \mu}{2} - F = 0,$$

implying:

$$t^s = \frac{\mu + p_g - p_e}{2} \pm \frac{1}{2}\sqrt{(\mu + p_g - p_e)^2 - 8F}.$$

By assumption, $\mu > 0$ and $p_e \leq p_g - \mu + t < p_g$ in the price domain we are now studying. Accordingly, $\mu + p_g - p_e \geq 0$, which implies that both solutions of the last equation are positive. However, as social welfare is decreasing in t, the regulator chooses the lowest feasible tariff:

$$t^s = \frac{\mu + p_g - p_e}{2} - \frac{1}{2}\sqrt{(\mu + p_g - p_e)^2 - 8F}, \tag{8}$$

For the last expression to be well defined, the fixed cost of the TSO is sufficiently low so that its break-even is feasible:

$$0 < F \leq \frac{(\mu + p_g - p_e)^2}{8}, \tag{9}$$

which is satisfied under Assumption 2. Introducing t^s in (8) in the welfare function, we obtain that, for this price domain, the overall welfare with the second-best tariff is:

$$W^s = \frac{3}{16}(\mu + p_g - p_e)\left[\mu + p_g - p_e + \sqrt{(\mu + p_g - p_e)^2 - 8F}\right] - \frac{3}{4}F.$$

Note that the tariff t^s that is needed to guarantee the TSO break-even may be so high that the market structure switches from a monopoly (with the entrant alone in the market) to a duopoly because the domain condition we are imposing is violated for this value of the transmission tariff. For that to occur, we must have:

$$p_e \leq p_g - \mu + t^s$$

Replacing in the last inequality, the expression for t^s, given in (8) and isolating the term with the root on the RHS of the inequality, we obtain:

$$p_e - \left(p_g - \mu + \frac{\mu + p_g - p_e}{2}\right) \geq -\frac{1}{2}\sqrt{(\mu + p_g - p_e)^2 - 8F}$$

or, equivalently, :

$$3c - \mu - 3p_e \leq \sqrt{(\mu + p_g - p_e)^2 - 8F}$$

For $p_e \geq p_g - \frac{\mu}{3}$, the inequality above is always true and the market structure in which the entrant becomes monopolist is not part of the equilibrium path (foreign gas is too expensive). For $p_e < p_g - \frac{\mu}{3}$, the inequality above holds if $F \leq (p_e - p_g)(p_g - \mu - p_e)$. Accordingly, under second-best regulation, the incumbent firm is always active in the downstream market, provided that the fixed cost F is not too high and/or p_e is not too low.

Let us now check how market outcomes change, when the incumbent firm is active in the market. Start by considering the case in which $p_g - \mu + t < p_e \leq p_g + \frac{\mu - t}{2}$, with

$$\pi_T(t) = t \times \frac{p_g - p_e + 2\mu - 2t}{3} - F$$

As the regulator aims at choosing the lowest value for t that ensures the economic viability of the transmission operator, it will set:

$$t^s = \frac{p_g - p_e + 2\mu}{4} - \frac{1}{4}\sqrt{(p_g - p_e + 2\mu)^2 - 24F} \tag{10}$$

It follows immediately that, if $F > \frac{(p_g - p_e + 2\mu)^2}{24}$, there is no value for t that allows the TSO to make non-negative profits. If

$$F \leq \frac{(p_g - p_e + 2\mu)^2}{24} \tag{11}$$

the regulator sets t^s in (10). The overall welfare will depend on whether the entrant buys natural gas to the incumbent firm or it imports in in the market. In fact, although we have

$$\Big(q_i(t), q_e(t)\Big) = \left(\frac{p_e - p_g + \mu - t}{3}, \frac{2p_g - 2p_e + \mu - t}{3}\right)$$

when $p_g - \mu + t < p_e \leq p_g + \frac{\mu - t}{2}$, overall welfare in this region depends on whether the entrant buys gas from the incumbent firm or imports it in the foreign market (See the Proof of Proposition 3 for further details). When $p_g - \mu + t^s < p_e < p_g$, the entrant imports the gas and the (maximum) overall welfare is obtained by substituting this value of t^s in (21), with:

$$W^s = \frac{1}{18}\left[10(p_g - p_e)^2 + 4\mu(p_g - p_e + \mu) + (p_g - p_e + 2\mu)\sqrt{(p_g - p_e + 2\mu)^2 - 24F} - 12F\right]$$

When $p_g \leq p_e < p_g + \frac{\mu - t^s}{2}$, the entrant buys the gas from the incumbent. In that case (maximum) overall welfare is given by evaluating (22) at $t = t^s$ in (10), yielding:

$$W^s = \frac{1}{36}\left[(p_e - p_g + 4\mu)\,(2\mu - p_e + p_g) + \sqrt{-24F + (p_g + 2\mu - p_e)^2}\,(p_e - p_g + 4\mu) - 24F\right].$$

Suppose now that $p_e \geq p_g + \frac{\mu - t}{2}$, which implies that the incumbent firm is alone in the gas market. Consider further that the regulator sets the transmission tariff t^s that ensures the economic viability of the transmission operator:

$$\pi_T(t^s) = 0 \;\Leftrightarrow t^s\left(\frac{\mu - t^s}{2}\right) - F = 0,$$

implying

$$t^s = \frac{\mu}{2} - \frac{1}{2}\sqrt{\mu^2 - 8F},$$

provided

$$F \leq \frac{\mu^2}{8}. \tag{12}$$

Otherwise, the break-even of the TSO is not achievable. When fixed costs are sufficiently low, the maximum attainable welfare is:

$$W^s = \frac{3}{16}\left(\mu^2 - 4F + \mu\sqrt{\mu^2 - 8F}\right)$$

4 Legal unbundling

We now address a market with legal unbundling, in which the transmission firm and the incumbent firm are legally separated but they are part of the same economic corporation, meaning that firms strategically maximize joint profits of the corporative group.[20] As before, the integrated firm (firm i) and the entrant (firm e) may supply natural gas in the downstream market, with the features described in the previous model. The entrant may buy natural gas in the domestic market (at price p_i) or in the foreign market (at price p_e), whereas the incumbent obtains natural gas at price p_g. As before, both firms have an additional marginal cost $c \geq 0$ that captures distribution and marketing costs. The firm in charge of transmission has the fixed sunk cost F (that can be interpreted as the initial cost of installing the gas pipelines), which will affect the joint profit of the incumbent corporation.[21] When the entrant is active in the final market, it must use the transmission infrastructure of the incumbent corporation, paying the regulated transmission tariff, $t \geq 0$.[22]

The structure of the market is represented in Figure 3.

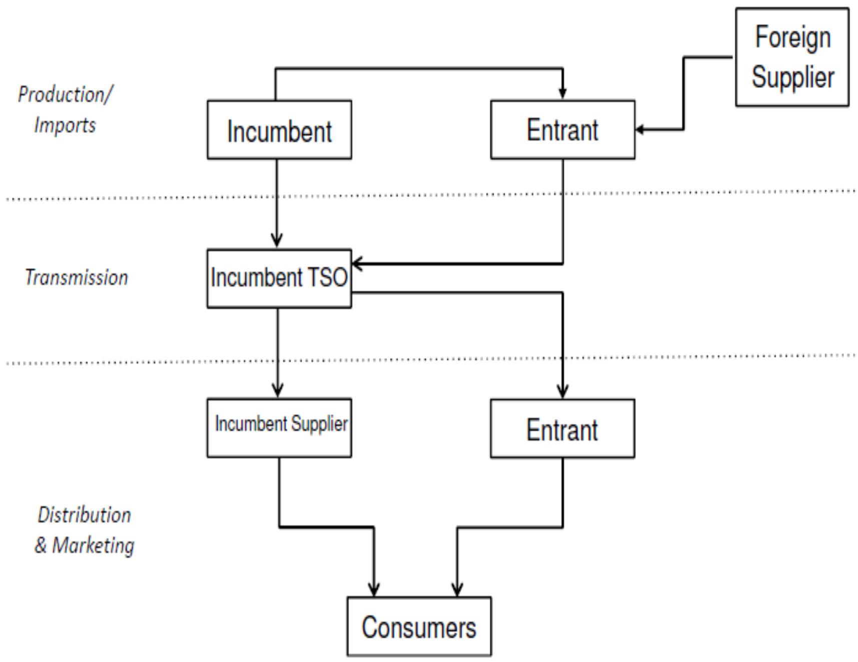

Fig. 3: Legal unbundling framework

The timing of the game is the same as in the model with ownership unbundling and the game

[20]In the context of a regulatory framework based on legal unbundling, all the previous results would remain valid if firms maximize their own individual profits despite being part of an economic corporation (i.e. ownership unbundling and legal unbundling would be equivalent, which is not often the case).

[21]We are assuming that the magnitude of F does not depend on whether the transmission network is owned by the incumbent corporation or by a third independent party.

[22]Under legal unbundling, the incumbent downstream firm must also pay the transmission tariff to the TSO. However this does not affect the profit of the incumbent corporation (the cost of the downstream firm is offset by the corresponding TSO's revenue).

is solved by backwards induction. We start by investigating outcomes in the downstream market, if the entrant buys the gas in the domestic market. Below, the superscript lu is used to denote outcomes under legal unbundling. As mentioned before, in this regulatory regime, although the firm in charge of gas transmission and the incumbent suppliers are legally independent firms, we assume they coordinate actions in order to maximize the joint profit of the incumbent corporation, given by:

$$\pi_{i,d}^{lu}\left(q_i, q_e, p_i, t\right) = \left(\mu - q_i - q_e\right) q_i + \left(p_i + t - p_g\right) q_e - F,$$

where we have omitted the revenues and the costs of the incumbent corporation regarding the transport its own gas (since the additional revenue of the firm transporting the incumbent's gas will be cancelled out by the additional incumbent's cost). The profit function of the entrant is:

$$\pi_{e,d}^{lu}\left(q_i, q_e, p_i, t\right) = \left(\mu + p_g - q_i - q_e - t - p_i\right) q_e. \tag{13}$$

In an interior solution with both firms active in the market, the optimal output levels solve the following the system of first-order conditions:

$$\begin{cases} \frac{\partial \pi_{i,d}^{lu}(q_i,q_e,p_i,t)}{\partial q_i} = 0 \\ \frac{\partial \pi_{e,d}^{lu}(q_i,q_e,p_i,t)}{\partial q_e} = 0 \end{cases} \Rightarrow \begin{cases} q_{i,d}^{lu}\left(p_i, t\right) = \frac{\mu - p_g + p_i + t}{3} \\ q_{e,d}^{lu}\left(p_i, t\right) = \frac{\mu + 2(p_g - p_i - t)}{3} \end{cases},$$

since the SOC are trivially satisfied. The incumbent and the entrant are both active in the final market if $-\mu < p_i - p_g + t < \frac{\mu}{2}$.

When the entrant buys the gas in the foreign market, the profit functions of the incumbent and the entrant are respectively given by:

$$\pi_{i,f}^{lu}\left(q_i, q_e, t\right) = \left(\mu - q_i - q_e\right) q_i + t q_e - F,$$

and:

$$\pi_{e,f}^{lu}\left(q_i, q_e, t\right) = \left(\mu + p_g - q_i - q_e - t - p_e\right) q_e.$$

In an interior solution, the FOC imply

$$q_{i,f}^{lu}\left(t\right) = \frac{\mu - p_g + p_e + t}{3} \text{ and } q_{e,f}^{lu}\left(t\right) = \frac{\mu + 2(p_g - p_e - t)}{3}. \tag{14}$$

The incumbent firm and the entrant sell positive quantities in the final market if $-\mu < t + p_e - p_g < \frac{\mu}{2}$.

In the third stage, following the same steps as in the case of ownership unbundling, it is straightforward to conclude that when the entrant is active in the downstream market, it optimally buys the gas from the supplier that charges the lowest price in the upstream market.

Let us consider first $p_i \leq p_e$, so that the entrant buys the gas from the incumbent. In this case, the profit of the incumbent, given the expected outcome in the subsequent stages is:

$$\pi_{i,d}^{lu}\left(p_i, t\right) = \frac{\mu^2 - 5(p_g - p_i - t)(p_g - p_i - t + \mu)}{9} - F. \tag{15}$$

Thus, in the second stage, we must have

$$\frac{d\pi_{i,d}^{lu}\left(p_i, t\right)}{dp_i} = 0 \;\Leftrightarrow\; p_{i,d}\left(t\right) = \frac{\mu}{2} + p_g - t,$$

which would block the entry of the firm. Hence, depending on the value of p_e, two scenarios are possible. When $p_e < \frac{\mu}{2} + p_g - t$, the entry is not blocked since buying gas in the foreign market is an economically viable possibility. If $p_e > \frac{\mu}{2} + p_g - t$, there is market foreclosure. For $p_e < \frac{\mu}{2} + p_g - t$, the incumbent will be interested in selling natural gas at price p_e, provided $p_e > p_g$ since

$$\pi_{i,d}^{lu}\left(t\right) > \pi_{i,f}^{lu}\left(t\right) \;\Leftrightarrow\; \frac{1}{3}\left(p_g - p_e\right)\left(2p_e - \mu - 2p_g + 2t\right) > 0.$$

When $p_e \leq p_g$, the incumbent is not willing to sell any gas to the entrant in the upstream market since it would incur in losses when fixing a price equal to p_e. As in the model with ownership unbundling, when $p_e < p_g$, the entrant may be much more efficient than the integrated firm, evicting the latter from the market. In light of the outcomes in the downstream market, we conclude that the integrated firm could be evicted from the downstream market when:

$$p_e < p_g - \mu - t.$$

In light of the previous results, it is straightforward to obtain the second-stage equilibrium output levels[23]

$$\left(q_i^{lu}(t), q_e^{lu}(t)\right) = \begin{cases} \left(0, \frac{p_g+\mu-p_e-t}{2}\right) & if \quad 0 \leq p_e \leq p_g - \mu - t \\ \left(\frac{\mu-p_g+p_e+t}{3}, \frac{\mu+2(p_g-p_e-t)}{3}\right) & if \quad p_g - \mu - t < p_e < \frac{\mu}{2} + p_g - t \\ \left(0, \frac{\mu}{2}\right) & if \quad p_e \geq \frac{\mu}{2} + p_g - t \end{cases}$$

and the corresponding overall welfare

[23] Calculations were ommitted since the procedure to obtain these results is completely analogous to the one that was used in the baseline model with ownership unbundling.

$$W^{lu}(t)=\begin{cases}\frac{3(\mu+p_g-t-p_e)^2}{8}+\frac{t(\mu-p_g-p_e-t)}{2}-F & if \quad 0\leq p_e\leq p_g-\mu-t\\ \frac{4(p_g-p_e+\mu)^2+7(p_g-p_e)^2+4\mu^2-t[10(p_g-p_e)+t+2\mu]}{18}-F & if \quad p_g-\mu-t<p_e<p_g\\ \frac{4\mu^2+(p_g-p_e)(2t+\mu)-\mu t}{9}-\frac{(p_g-p_e+t)^2}{18}-F. & if \quad p_g\leq p_e<\frac{\mu}{2}+p_g-t\\ \frac{3}{8}\mu^2-F & if \quad p_e\geq\frac{\mu}{2}+p_g-t\end{cases} \tag{16}$$

We now look for the first-best results arising when the regulator sets the transmission tariff that maximizes overall welfare, W^{lu}.

Proposition 4 *The first-best transmission tariff in a regime of legal unbundling is* $t^{v*}=0$*. The corresponding overall welfare is given by:*

$$W^{lu}(t)=\begin{cases}\frac{3}{8}\left(p_e-\mu-p_g\right)^2-F & if \quad 0\leq p_e<p_g-\mu\\ \frac{8\mu^2+8\mu(p_g-p_e)+11(p_g-p_e)^2}{18}-F & if \quad p_g-\mu<p_e<p_g\\ \frac{(2\mu-p_e+p_g)(4\mu+p_e-p_g)}{18}-F & if \quad p_g<p_e\leq\frac{\mu}{2}+p_g\\ \frac{3}{8}\mu^2-F & if \quad p_e>\frac{\mu}{2}+p_g\end{cases} \tag{17}$$

The Proof of the previous Proposition is omitted since it follows exactly the same steps as the proof of Proposition 3, *mutatis mutandis.* The overall welfare (17) is obtained by replacing $t^*=0$ in (16).

The previous Proposition shows that in the model with legal unbundling (as in the ownership unbundling model), the first-best transmission tariff is null. Again, this result can be explained by the nature of interaction in the downstream market (where firms compete *à la* Cournot) together with the transmission technology (the cost structure associated with the transmission infrastructure is such that all the costs have a fixed nature).

However, as argued in Sub-section 2.4, in a more realistic set-up the regulator's actions are constrained by the need to guarantee the economic viability of transmission activities, it will set the lowest tariff that yields $\pi_T\left(t^s\right)=0$.[24] Thus, in a second-best regulatory policy, the regulator solves

[24] In a regime of legal unbundling, the incumbent gas retailer and the TSO are part of the same economic corporation but they are legally separated entities. In order to avoid cross-subsidization issues, the transmission tariff set by the regulator must only take into account the profits associated to the transmission activity (i.e. the TSO's profit).

the following maximization problem:

$$\max_t W(t) \quad \text{s.t.} \quad t\left[q_i^{lu}(t) + q_m^{lu}(t)\right] - F = 0.$$

Accordingly, we could easily describe the optimal transmission tariff in each price domain, following the method adopted in Section 2.4.[25]

In what follows, we shed some light on welfare outcomes of ownership unbundling versus legal unbundling, both in the case of first-best regulation and the case of second-best regulation.

5 Ownership versus Legal unbundling

When the regulator's action is not constrained by the economic viability of the regulated activities, we get that overall welfare is the same in both regimes since in both cases the regulator sets the lowest possible transmission tariff, $t^* = 0$. This result follows from the fact that in both regimes (ownership unbundling and legal unbundling) first-best regulation implies marginal cost pricing (i.e. the optimal transmission tariff is equal to the transmission marginal cost, set to zero w.l.o.g.). Accordingly, there is no positive mark-up in the midstream (transmission) market, which eliminates double marginalization problems as well as third-party access issues. When the regulator is concerned with the economic viability of transmission activities, it will set the lowest tariff that yields $\pi_T(t^s) = 0$, regardless of the unbundling regime. In the case of ownership unbundling, the regulator solves the problem

$$\max_t W(t) \quad \text{s.t.} \quad t\left[q_i(t) + q_m(t)\right] - F = 0, \tag{18}$$

whereas in the case of legal unbundling, it solves

$$\max_t W(t) \quad \text{s.t.} \quad t\left[q_i^{lu}(t) + q_m^{lu}(t)\right] - F = 0. \tag{19}$$

Comparing (18) and (19), it is clear that the regulator's choice on t^s under the two regulatory regimes only differ to the extent that they might yield different output levels in the downstream market. Let us define total output levels $Q^{ou}(t) = q_i(t) + q_m(t)$ as the total output in the downstream market with ownership unbundling:

[25] The solutions are available from the authors upon request.

$$Q^{ou}(t) = \begin{cases} \frac{p_g - p_e + \mu - t}{2} & if \quad 0 \leq p_e \leq p_g - \mu + t \\ \frac{p_g - p_e + 2\mu - 2t}{3} & if \quad p_g - \mu + t < p_e < p_g + \frac{\mu - t}{2} \\ \frac{\mu - t}{2} & if \quad p_e \geq p_g + \frac{\mu - t}{2} \end{cases}$$

and $Q^{lu}(t) = q_i^{lu}(t) + q_m^{lu}(t)$, as the total output in the downstream market with legal unbundling:

$$Q^{lu}(t) = \begin{cases} \frac{p_g - p_e + \mu - t}{2} & if \quad 0 \leq p_e \leq p_g - \mu - t \\ \frac{p_g - p_e - t + 2\mu}{3} & if \quad p_g - \mu - t < p_e < p_g + \frac{\mu}{2} - t \\ \frac{\mu}{2} & if \quad p \geq p_g + \frac{\mu}{2} - t \end{cases}$$

For a given transmission tariff t, we have that overall welfare with ownership unbundling is smaller than overall welfare with legal unbundling iff $Q^{ou}(t) < Q^{lu}(t)$. In that case, we expect the second-best transmission tariff to be lower with legal unbundling than with ownership unbundling (when $Q^{ou}(t) < Q^{lu}(t)$, the fixed cost F is distributed by a greater gas quantity).

Accordingly, by comparing $Q^{ou}(t)$ and $Q^{lu}(t)$ for a given tariff, we can shed some light on the comparative welfare outcomes with ownership and legal unbundling.

First, let us suppose that the regulator sets a transmission tariff such that $0 \leq p_e \leq p_g - \mu - t$. In this case, only the entrant is active in the downstream market regardless of the owner of the transmission network. In this case, the total quantity in the downstream market is the same with and without ownership unbundling: $Q^{ou}(t) = Q^{lu}(t)$. Therefore, the regulator chooses the same (second-best) transmission tariff in the two regimes and welfare outcomes are similar, regardless of how restrict unbundling criteria are. When $p_g - \mu - t < p_e \leq p_g - \mu + t$, with ownership unbundling we have a monopoly market (in which only the entrant is active), whereas duopoly outcomes arise with legal unbundling. For a given t in this price range, we have $Q^{ou}(t) < Q^{lu}(t)$ since:

$$\frac{p_g - p_e + \mu - t}{2} < \frac{p_g - p_e - t + 2\mu}{3} \Leftrightarrow \frac{1}{6}\left(p_g - t - \mu - p_e\right) < 0$$

When the regulator chooses a transmission tariff t such that $p_g - \mu + t < p_e \leq p_g + \frac{\mu}{2} - t$, the two firms will be active in the market, regardless of the regulatory framework. In this case, we have that: $Q^{ou}(t) < Q^{lu}(t)$ since

$$Q^{lu}(t) - Q^{ou}(t) = \frac{1}{3}t > 0$$

As there are no marginal transmission costs and $t > 0$ (in order to guarantee the economic viability of the transmission operator), provided that $p_g - \mu + t < p_e \leq p_g + \frac{\mu}{2} - t$, the magnitude of the transmission tariff that ensures the break-even of the transmission operator tends to be lower under legal unbundling. As the overall welfare is decreasing in t, it follows that, welfare with ownership unbundling is lower than welfare with legal unbundling.

If the regulator chooses t such that $p_g + \frac{\mu}{2} - t < p_e < p_g + \frac{\mu - t}{2}$, the incumbent will be surely monopolist in the downstream market if it owns the transmission network (legal unbundling) and it will compete with the entrant under ownership unbundling. Again, we have $Q^{ou}(t) < Q^{lu}(t)$ since

$$\frac{\mu}{2} > \frac{p_g - p_e + 2\mu - 2t}{3} \;\Leftrightarrow\; p_e > p_g + \frac{\mu}{2} - 2t,$$

which is surely satisfied in the domain we are considering. Finally, if $p_e \geq p_g + \frac{\mu - t}{2}$, the incumbent firm will be monopolist in the downstream market with and without ownership unbundling. Nonetheless, for a given t, we still have $Q^{lu}(t) > Q^{ou}(t)$ (since $t > 0$ to ensure the economic viability of the TSO).

The previous results clearly illustrate how the value of the transmission tariff may affect equilibrium market structure in the downstream market. However, even when the there are more competitors in the downstream market under ownership unbundling than under legal unbundling (i.e. when $p_g + \frac{\mu}{2} - t < p_e < p_g + \frac{\mu - t}{2}$), for a given t, output levels are always larger with legal unbundling than with ownership unbundling. The following Lemma summarizes our results regarding unbundling effects on overall welfare under second-best regulation.

Lemma 5 *For a given t, we have, $Q^{lu}(t) - Q^{ou}(t) > 0$ for any p_e and μ. Therefore, under second-best regulation, we expect:*
(i) a higher transmission tariff with ownership unbundling than with legal unbundling;
(ii) lower overall welfare with ownership unbundling than with legal unbundling.

The Proof of the previous Lemma is omitted since it follows directly from our previous analysis on the comparison between $Q^{lu}(t)$ and $Q^{ou}(t)$.

The intuition for the previous result is quite straightforward. When the incumbent firm owns the transmission network it internalizes the transmission cost (the incumbent supplier cost is a revenue of the incumbent TSO) and therefore it has an incentive to sell larger gas amounts in the final market. This result is a reminiscence of the double marginalization problem. Under second-best regulation, we must have a positive price-cost margin (i.e. the difference between the transmission tariff and the TSO's marginal cost is positive) to ensure the break-even of the TSO (to recover the fixed cost F). Under legal unbundling, the incumbent corporation's payoff from own gas sales is not affected by the transmission tariff (which eliminates double marginalization issues for the incumbent corporation). Thus the firm will sell more gas in this regime than in the ownership unbundling regime. Moreover, with legal unbundling, the incumbent corporation also gets some benefits from the entrant's sales in the downstream market (via TSO's revenues).

6 Conclusions

In this paper, we build a theoretical model to investigate whether transmission regulation and unbundling criteria (ownership versus legal unbundling) may induce competitive bottlenecks in gas markets. In the context of a simple gas industry model, we showed that the transmission tariff as well as firms' (possibly different) contracting conditions in the upstream market (namely in terms of the acquisition prices of natural gas) are key determinants of the market structure in the downstream market. In particular, when the contracting conditions of the entrant in the foreign market are very unfavorable (i.e. price of the gas in the foreign market, p_e, is prohibitively high), the incumbent firm can successfully adopt a market foreclosure strategy, regardless of the transmission tariff set by the regulator.

We also analyze optimal regulatory policies concerning third party access to the transmission network. In particular, we focus on price regulation issues, assuming that the regulator unilaterally fixes the transmission tariff under two alternative regulatory goals: overall welfare maximization and break-even of the regulated activities (i.e. the break-even of the TSO).

When the regulator aims at maximizing overall welfare, the optimal transmission tariff consists in promoting free access to the transmission network, regardless of the unbundling criteria.

When the regulator aims at guaranteeing the break-even of the TSO, it needs to deviate from first-best outcomes, setting a positive transmission tariff (to cover the TSO's fixed cost). As expected, in both regimes, the value to the break-even transmission tariff is increasing with the magnitude of the TSO's fixed costs. In general, the transmission tariff is higher under ownership unbundling then under legal unbundling, implying a lower overall welfare level in the first case. Indeed, for a given transmission tariff, we find that output levels (final prices) in the downstream market are always higher (lower) under legal unbundling than under ownership unbundling. When the incumbent firm owns the transmission network it internalizes the transmission cost, selling larger quantities in the final market.

An important result arising from our analysis is that the effectiveness of market foreclosure strategies crucially depend on the contracting conditions of new firms. Our model puts on evidence that the integration of the national markets of the Member States (at least at a regional level) is a crucial step to the creation of a fully liberalized internal market, as mentioned in article 7 of the Directive 2003/55/EC.

Another important contribution of this work refers to the comparison of welfare outcomes under legal and ownership unbundling. In line with recent empirical works, e.g. Growitsch and Stronzik (2014), we find that gas prices tend to be lower with legal unbundling than with ownership unbundling.

In the future work, it would be interesting to develop an extension of our model, in order to compare ownership and legal unbundling regimes in what concerns the market bottlenecks created by transaction costs and asymmetric information issues arising both in the relationship among firms in the gas system and in the relationship between the regulator and the regulated firms (regarding this last issue, see e.g. Laffont and Tirole, 1994).

Another direction to make our model closer to the reality could be the analysis of more sophisticated tariff systems arising in set-ups with several entry-exit points (e.g., to compare the postage stamp and the entry-exit tariff systems) for the natural gas transmission network.[26] Finally, it would also be worthy to develop a multi-country approach in order to study whether regulatory international cooperation and tariff harmonization may increase competitive pressure in the natural gas European market(s).

[26] See Lapuerta and Moselle (2002) and Alonso *et al.* (2010) or Brandão *et al.* (2014) for more information on the characteristics of these tariff systems.

Appendix

Proof of Proposition 3

The expression for total surplus, $W(t)$ is given by

$$W(t) = \pi_m(t) + \pi_i(t) + CS(t) + \pi_t(t)$$

1. If $0 \leq p_e < p_g - \mu + t$:

$$\begin{aligned} W(t) &= \frac{(p_g - p_e + \mu - t)^2}{4} + 0 + \frac{(p_g - p_e - t + \mu)^2}{8} + t \times \frac{p_g - p_e + \mu - t}{2} - F \\ &= \frac{1}{8}(p_g - p_e + \mu - t)(3p_g - 3p_e + 3\mu + t) - F \end{aligned} \tag{20}$$

Notice that, for $p_e < p_g$ (which is holds in the domain we are considering), we have that total welfare is strictly decreasing in t, $\frac{dW}{dt} = \frac{p_e - p_g - t - \mu}{4} < 0$. Thus, for this domain of p_e, a regulator that does not care about the economic viability of the transmission operator, will optimally set $t^* = 0$, and total surplus would be $W^* = \frac{3}{8}(p_g - p_e + \mu)^2 - F$

2. If $p_g - \mu + t \leq p_e < p_g$:

$$\begin{aligned} W(t) &= \frac{(2p_g - 2p_e + \mu - t)^2}{9} + \frac{(p_g - p_e - \mu + t)^2}{9} + \frac{(p_g - p_e + 2\mu - 2t)^2}{18} + t \times \frac{p_g - p_e + 2\mu - 2t}{3} - F \\ &= -\frac{2}{9}t^2 - \frac{p_g - p_e + 2\mu}{9}t + \frac{11(p_g - p_e)^2 + 8\mu(p_g - p_e + \mu)}{18} - F \end{aligned} \tag{21}$$

with $\frac{dW}{dt} = -\frac{p_g - p_e + 2(\mu + 2t)}{9} < 0$.Thus, for this domain of p_e, the regulator will optimally choose the lowest possible tariff in this domain, i.e. $t^* = 0$ and total surplus will be:

$$W^* = \frac{11(p_g - p_e)^2 + 8\mu(p_g - p_e + \mu)}{18} - F$$

3. If $p_g < p_e \leq p_g + \frac{\mu - t}{2}$:

$$\begin{aligned} W(t) = &\frac{(2p_g - 2p_e + \mu - t)^2}{9} + \frac{-5p_e^2 + 5p_e(2p_g + \mu - t) - 5p_g(p_g + \mu - t) + (\mu - t)^2}{9} \\ &+ \frac{(p_e - p_g + 2t - 2\mu)^2}{18} + t \times \frac{p_g - p_e + 2\mu - 2t}{3} - F \\ = &-\frac{2}{9}t^2 - \frac{2(p_e - p_g + \mu)}{9}t + \frac{\mu(4\mu - p_e + p_g)}{9} - \frac{(p_e - p_g)^2}{18} - F \end{aligned} \tag{22}$$

Again, $\frac{dW}{dt} = -\frac{2(p_e - p_g + 2t + \mu)}{9} < 0$. Thus, for this domain of p_e, the regulator chooses the lowest possible tariff, $t^* = 0$ and total surplus is equal to:

$$W^* = \frac{(2\mu - p_e + p_g)(4\mu + p_e - p_g)}{18} - F.$$

4. Finally, if $p_e > p_g + \frac{\mu - t}{2}$:

$$W(t) = 0 + \frac{(\mu - t)^2}{4} + \frac{(\mu - t)^2}{8} + t \times \frac{\mu - t}{2} - F = \frac{(\mu - t)(3\mu + t)}{8} - F$$

As $\frac{dW}{dt} = -\frac{\mu + t}{4} < 0$, we conclude that W is also decreasing in t for $p_e > p_g + \frac{\mu - t}{2}$. When $t = 0$, the previous condition writes as $p_e > p_g + \frac{\mu}{2}$, implying $2p_g + \mu - 2p_e < 0$. Thus, also for this price domain, the regulator chooses the lowest possible value of $t^* = 0$ and the (maximum) overall welfare is $W^* = \frac{3}{8}\mu^2 - F$.

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Evolution of prices and margin in the Spanish retail automotive fuels market: What do they reflect?

Alejandro Bello

Dpto. Gestión de Empresas, Universidad Pública de Navarra

Ignacio Contín-Pilart[1]

Dpto. Gestión de Empresas and INSIDE, Universidad Pública de Navarra

Mª Blanca Palacios

Dpto. Estadística e Investigación Operativa, Universidad Pública de Navarra

Abstract.

Since the abolishment of the Spanish state monopoly on oil products in 1993, the Spanish-based refiners (Repsol, Cepsa and BP) have lost market share in the retail sector, while new operators have gained ground. However, a high horizontal and vertical concentration still persists today, which has fuelled a continuous discussion about the non-competitive market behavior of the oil companies. This paper brings clarity about the competitive functioning of the Spanish retail automotive fuels market, analyzing how prices and margins have evolve since the beginning of the current century. We illustrate that the data are consistent with some firms exercising market power during the recessive period of the Spanish economy (1998-2013), in which demand for automotive fuels decreased around 30%, while the gross margins per liter sold jumped above the European levels. This has allowed oil companies to maintain their profits in the retail sector during the crisis. Overall, our paper shows, on the one hand, how difficult it is to achieve dynamic and competitive energy markets when restructuring processes of former monopolies pursues the maintenance of the status-quo and the creation of national champions and, on the other hand, the necessity to adopt a very competitive approach in the medium-long term to enhance competition. This means to carry out new structural reforms, which are costly, and may increase litigation between firms and Antitrust and Energy Regulatory Authorities.

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[1] Corresponding author. Email: contin@unavarra.es. The authors gratefully acknowledges the financial support from the *Ministerio de Economía y Competitividad* projects (ECO2010-21242-C03-03 y ECO2010-21393-C04-03).

Introduction

The consumption of automotive fuels (gasoline and automotive diesel) increased steadily in Spain over the first years of the current century due to the booming economy. This changed in 2008 as the economy went into recession, battered by the global credit crisis and by the Spanish property market collapsed. More than 3 million jobs, over half of them in the construction and related sectors, were lost and the unemployment rate reached its highest level of 26.94% in the first quarter of 2013 (Chislett, 2014). The domestic demand went down and, accordingly, the consumption of automotive fuels decreased since July 2013 until February 2013; when it reached its lowest peak (See Figure 2).

On the supply side, the recession has had a virulent impact on construction, but it has also severely affected industrial and service activity (Ortega and Peñalosa, 2012). Virtually, all economic sectors, and not only the banking system or the building industry, have restructured and adjusted their productive capacity to better match new domestic demand. One of the few exceptions to this restructuring process that has affected the Spanish economy as a whole is the oil industry. Indeed, the Spanish-based refiners have invested more than € 6,500 million since 2008 to add upgrading plants to their refineries, thereby increasing the Spanish refining capacity (CNMC, 2015; OECD 2013)[2]. Meanwhile, the storage capacity for crude oil and refining products as well as the length of the pipeline system has remained virtually constant in Spain over the last years. Finally, the number of service stations has not stopped growing over this period.

Although corporate profits have been negatively affected by the economic crisis in Spain, "the total gross margin" of the retail automotive fuels sector has remained fairly steady over this century (Figure 7). The Spanish Antitrust Authority (CNC:

[2] On the contrary, 15 refineries were closed down in the EU between 2008 and 2013, losing a 11% of the total capacity installed in the EU in 2008 (CNMC, 2015).

Comisión Nacional de la Competencia) pointed out that the gross margin per liter sold, both in gasoline and diesel, had growth around 20% between 2007 and 2010, despite the sharp decline in consumption. In addition, prices before taxes would have increased in Spain more than elsewhere in Europe (CNC, 2012). According to the Spanish Antitrust Authority, this evolution of prices before taxes and gross margins per liter sold would reflect a lack of competition in the Spanish retail automotive fuels market. The Spanish associations of oil companies (*Asociación Española de Operadores Petrolíferos*, AOP) responded to this statement arguing that the report (CNC, 2012)'s conclusion of lack of competition was based on wrong analysis and data and therefore was "invalid"[3].

This paper intend to bring clarity about the competitive functioning of the Spanish retail automotive fuels market, analyzing how prices and margins have evolved since the beginning of the current century. The Spanish oil industry experienced one of the most complex processes of restructuring and liberalization in the recent history of Europe which culminated with the abolishment of the state monopoly on oil products in 1993 (Correljé, 1994; Contín et al., 1999). Since them, the Spanish-based refiners (Repsol, Cepsa and BP) have lost market share in the retail sector, while new operators (independent service stations, hypermarkets, etc.) have gained ground. However, a high horizontal and vertical concentration persists which has fuelled, as we have already seen, a continuous discussion about the non-competitive market behavior of the oil companies. Our paper will allow us to advance the understanding of how prices are formed in the Spanish retail automotive fuels market, which provides useful insights about the consequences for the competitive functioning of the energy markets when the restructuring processes pursue the maintenance of the status-quo and the creation of "national champions". More specifically, our paper shows how difficult is to achieve

[3] http://www.aop.es/pdf/ResumenConclusionesAnalisisBCGsobreInformeCNC-12-07-12.pdf

dynamic and competitive energy markets in these cases. This obliges, in turn, the Public Authorities to adopt a very competitive approach in the medium-long term to enhance competition, such as approving and implementing new structural reforms, which are costly, and may increase litigation between firms and Antitrust and Sectoral Authorities.

The paper is organized as follows. The next section briefly outlines the relate literature and discusses the abuse of market power in the Spanish automotive retail fuels market. Section 3 describes the main features of this market. Section presents 4 the data and our empirical analysis. The section of conclusions completes the paper.

Related literature and abuse of market power in the Spanish automotive fuels market.

Allegations of "excessive" automotive fuels prices, abuse of market power and collusion have led the Spanish Antitrust Authority to investigate oil operators' pricing behavior and other commercial practices. When concentration is high enough, firms may able to exert some market power, leading to non-competitive outcomes, even when none of the firms would be individually dominant. Such non-competitive outcomes would rise from the individual profit-maximising responses of firms to market conditions. Likewise, collusion would allow firms to approximate their behavior that of a single dominant firm, maintaining "high" prices and profits. Collusion may be explicit, which is usually banned by antitrust law, or tacit, which usually arises when firms interact repeatedly (Ivalvi et al., 2003).

The incentive for collusion may be high in automotive fuels retailing (Eckert, 2013). Indeed, Houde (2010) points out that collusion could increase retail margins by a factor of four. In addition, several studies have suggested that retailers may be adopting pricing practices intended to facilitate price coordination, like simple dynamic reaction functions to facilitate tacit collusion (Slade, 1992) or like price leadership as a means to communicate price changes and make it easier for station to adjust their prices in response to cost or demand changes (prices at posted at each service station) (Kovác et al, 2005) or as a means to facilitate price restorations in Edgeworth cycle markets (Lewis, 2009; Wang, 2008, 2009; Atkinson et al., 2009).

Some features of the automotive fuels market favor the ability of firms to coordinate prices or to collude. Indeed, automotive fuels markets can, for the most part and also for Spain, be characterized as oligopolies with price-setting firms, selling homogenous fuels, with no capacity or information constraints and where large operators have multi-market contacts as they are national-wide. Conversely, other features can limit that ability, like differences in marginal costs and amenities, and in ownership structure, which lead to oil operators' heterogeneous network of service stations (Clark and Houde, 2013). In addition, the presence of maverick firms[4] in the retail sector, like hypermarkets or independent service stations, makes it more difficult to achieve price coordination.

The Spanish regulator for energy sectors (CNE: *La Comisión Nacional de la Energía*) states that pre-tax retail prices for gasoline and diesel (SGRP and SDR, respectively) have been in Spain above the European average ones (ERGP and EDR, respectively) since 2001[5](CNE, 2012). In addition, Figures 3 and 4 show how the difference between those prices has increased since mid-2008, a period of sharp decline in the consumption of these oil products. As a result, the Spanish gross margin per litre sold both for gasoline and for diesel has been, most of the time, above the European

[4] A maverick refers to a firm that as a different cost structure, production capacity, or product quality and that may have a stronger preference for the short term. It may, therefore, be more tempted to undercut rivals (Erutku and Hildebrand, 2010).

[5] However, Spanish retail prices for gasoline and diesel have been below the European average ones because Spain is of the countries with the lowest excessive taxes in Europe.

average margin since the beginning of this century and, in particular, from 2007 onward (Figures 6 and 7). In addition, CNE also point outs that retail prices were very similar among the stations of the different oil companies.

Likewise, the Spanish Antitrust Authority (CNC*)* started in July 2013 an investigation into suspected collusive behaviour in the retail automotive fuels market. In February 2015, the CNMC, which replaced the CNC and the CNE[6], fined for a total of € 32,4 million five oil companies (Respol, Cepsa, Disa, Meroil y Galp) for price fixing as well as exchanging information and agreeing to a non-aggression pact (*horizontal anticompetitive agreements*).

In addition, in 2009 the CNC had imposed fines totalling € 7,9 million to the Spanish based-refiners (Repsol, Cepsa and BP) for indirectly fixing prices in their CODO (Company Owner-Dealer Operator) and DODO (Dealer Owner-Dealer Operators) stations between 2001 and 2009, though provisions in the fuel supply that linked the fuel purchase price to a maximum or recommend retail prices at the station (*vertical anticompetitive agreements*). According to this CNC's decision, Repsol, Cepsa and BP should have changed those supply contracts, ceasing such price practices. However, in February and March 2015, the CNMC fined again the Spanish-based refiners for a total of € 12 million for non-compliance with the commitments imposed in 2009. This means that Repol, Cepsa and BP would have continued indirectly fixing prices in their CODO and DODO stations between 2009 and 2015. In fact, in July 2015 Repsol was again fined by the CNMC with € 22.6 million for coordinating prices with their branded stations[7].

[6] In October 2013, the CNC, the CNE and other sectoral regulators merged into one "super-regulator": *La Comisón Nacional de Mecados y Competencia*: CNMC.
[7] These investigations are ongoing since the allegations and fines of the Antistrust Autorithy have been appealed to a court, which has not yet taken any decision.

As stated, this paper seeks to shed light about the competitive functioning of the Spanish automotive fuels market from 2001 onward. In doing so, we will analyse the evolution of average monthly pre-tax prices for gasoline and diesel since 2001, when the Spanish pre-tax prices began to become above the European average prices (CNE, 2012), to May 2015. Specifically, and given the above allegations of anti-competitive behavior in this market, we will analyze whether the evolution of pre-tax prices are consistent with some firms exercising certain degree of market power. We use here the term "market power" in its comprehensive sense, referring to the ability of firms to unilaterally (market power held non-cooperatively by a single firm) or collusively (collusion among several firms) raise prices and margins.

The Spanish oil industry: an overview

Between 1927 and 1992, consumers of oil products in Spain were supplied by a state monopoly, which was gradually dismantling during a "transitional period" (1986-1992). This was one of the most complex processes of restructuring and liberalization in the recent history of Europe, aimed at ensuring the stability of the industry protecting the traditional refiners' status quo after the abolition of the Monopoly (January, 1993) and the setting up of a "national champion", Respol (Contín et al., 1999; Bello and Contín-Pilart, 2012). As a result a high degree of horizontal and vertical concentration emerged in the Spanish refining and retail sector, which has persisted to date.

Currently, there are 9 refineries in Spain (including one on Canarias) for automotive fuels, whose total production capacity of petroleum products is about 76 MMTn/year[8](Figure 1). Only Germany and Italy have more refineries that Spain in

[8] Spain relies on imported oil crude oil as indigenous production is negligible (less than 1% of crude oil supply) (IAE, 2015).

Europe. Of this nine refineries five belong to Repsol, three to Cepsa and one to BP. In terms of production capacity of petroleum products, Repsol has 58.8% of the total, Cepsa 34.1% and BP the remaining 7.1%. These figures show that the Spanish refining industry is highly concentrated (one of the most concentrated in Europe). Since 2012 Spain is a net exporter of oil products. Domestic production is slightly deficient in diesel and in surplus in gasoline. As such, in 2013 the refiners provisioned almost 100% of the gasoline and more than 80% of diesel consumed in Spain (CNMC, 2015)[9].

The Spanish oil sector has a highly efficient pipeline and storage system. The Spanish network of pipeline for oil products (over 4,000 km long), owned and operated by the *Compañía Logística de Hidrocarburos* (CLH), link the peninsular refineries and the main import ports with the 38 storage plants that serve the mainland (Figure 1). Thus, the pipeline network covers the whole peninsular territory and is available to every agent by means of a negotiated procedure (third-party access-TPA) which has non-discriminatory, transparent and objective technical and economic conditions (IEA, 2015). In addition, CLH is the main storage capacity holder (1.1 million m^3 for gasoline and 5.4 million m^3 for diesel in their 39 storage plants). For these reasons, CLH is considered the "essential facility" of the Spanish oil industry (CNMC, 2015). It is important to note that in CLH's capital are present the three Spanish-base refiners, accounting for 25% of its capital and several members of its Board of Directors, which allow them to have access and influence on the "essential facility" of the oil industry. The other shareholders of CLH are mainly investment funds.

[9] The current utilization rate of the refining capacity (80%) is slightly below that in 2012 and 2013 (80-85%) due to the increase in the Spanish total refining capacity (CNMC, 2015).

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Please Insert Figure 1

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Other distributors offer storage services as well, reaching the storage capacity for imports in their hands 802 million m^3 for gasoline and 3.8 million m^3 for diesel. This capacity is mainly located in two regions: Cataluña and País Vasco (CNMC, 2015). The CNMC (2015) also point out that the Spanish-based refiners have around 50-60% of the total gasoline storage capacity installed in the peninsular territory and around 40-50% of that for diesel.

At the retail level, several changes have takin place since the abolition of the Monopoly in 1993. These have encouraged a new competitive environment within the industry. The number of service stations has risen considerably, from 5,511 in 1992 to 9,782 in 2014 (Table 1) encouraging by the high average throughput per outlet. In fact, the average throughput per service stations remains one of the highest in Europe whereas the number of service stations per 100 km^2 or per vehicle is one of the lowest (CNE, 2009). The elimination of administrative and strategic entry barriers promoted a gradual entry of newcomers, among other Esso, Galp, Texaco, Avanti, etc. Furthermore, the number of independent unbranded service stations, including hypermarkets, has increased considerably. As a result, the retail market concentration has gradually reduced (Table 1). Yet, the Spanish based refiners together control currently around 60% of the service stations. However, the OECD (2015) rises this market share to 70-73% percent by sales volume (Repsol would have a market share of 45%; Cepsa, 16% and BP, 12% in gasoline and 9% in diesel). In addition, some large oil companies, like Shell, Total, Continental Oil, Avanti, Esso or Texaco have gradually exited the retail market since 2000.

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Please Insert Table 1

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Unlike most other European countries, in Spain the diesel and retail prices were regulated during the 1990s by a system of price ceilings. As only the three refiners controlled the market at that time, it was argued that a ceiling price regulation had to ensure that adequate consumer protection would accompany the process of liberalization. The price ceilings remained in force until June 1996 for diesel and until October 1998 for gasoline (Contín et al., 1999). Although some service stations linked to oil operators through exclusive distribution agreements are free to set prices, in practice it is found that recommend retail price from oil operators are followed in almost 100% by stations (OECD, 2015).

Finally, total demand for automotive fuels increased by 18.2% between 2001 and 2007 and then declined by 30.5% until 2013, as a result of the deep recession. It reached its highest peak in July 2007 and its lowest peak in February 2013 (Figure 2). Gasoline accounted for only a relatively small fraction of total demand (e.g. 20 % of total demand in 2013). Furthermore, the variation of the demand for automotive fuels has been in parallel to the variation of the demand for diesel, as the demand for gasoline has not stopped decreasing over our period of analysis due to the "dieselization" of the Spanish vehicle fleet. This dieselization started in 1999 and continues today strongly driven by the differences in tax rates for gasoline and diesel (IEA, 2015).

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Data, methodology and empirical results.

In this study, we analyze how the pre-tax retail prices of Euro 95 unleaded gasoline and of automotive diesel are formed in the Spanish retail market, by comparing them with the evolution of the average pre-tax retail prices of these oil products in Europe and with their spot prices. Specifically, the European average pre-tax retail price, both for gasoline and for diesel, will be the average price in six European countries: Belgium, Germany, France, Italy, Holland and the United Kingdom. We have chosen these countries because the average pre-tax retail price of such countries, considered "the more comparable" with Spain in Europe, was the main parameter included in the formulate used by the Spanish regulator to calculate weekly gasoline and diesel ceiling prices during the period of maximum price regulation. In addition, these European average prices have always been a "competitive reference" by the Spanish regulators (Contín et at., 1999). Finally, we will also compare the evolution of the gross retail margins per liter sold in Spain with that of the average gross retail margin in Europe, both for gasoline and for diesel.

The sample period is from January 2001 to May 2015, and involves 173 monthly observations. All retail prices are obtained directly from the Spanish Ministry of Industry web page, which, in turn, obtains them from the *Bulletin Petrolier* of the Directorate-General for Energy and Transport of the European Commission. Due to its geographical location, the gasoline and diesel spot prices "of reference" for Spain, which represent a theoretical cost of supply, are 30% based on North West European CIF quotations and 70% on Mediterranean CIF quotations[10]. These spot prices are also provided by the Ministry of Industry.

[10] This spot price "of reference" is hightly correlated (0.999) with that based equally on North West and Mediterranean market quotations, which is considered the most representative in Europe (CNMC, 2015).

Figure 3 captures the evolution of gasoline prices between January 2001 and May 2015. It shows how the gasoline spot price of reference for Spain as well as the Spanish pre-tax gasoline retail price (SGRP) and the European average pre-tax gasoline retail price (EGRP) sharply decreased in the second semester of 2008. Likewise, the difference between the Spanish (SGRP) and the European average price (EGRP) that had been very small between 2001 and 2007 quickly increase from mid-2008 onward. Figure 4 shows how the diesel spot price and the pre-tax diesel retail prices in Spain (SDRP) and in Europe (EDRP) have followed a similar evolution to that observed for gasoline.

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Please Insert Figure 3 and 4

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The information provided by the Ministry of Industry allows us to calculate the gross retail margin per liter sold in Spain and in Europe. Specifically, this margin is calculated as the difference between the pre-tax retail price of gasoline (or diesel) and its spot price (Meyler, 2009). The spot prices serve as reference to ex-refinery prices of gasoline and diesel. The gross margin includes distribution and marketing costs and profits.

Figure 5 shows how the monthly differences between the Spanish and the European gasoline gross retail margin have evolved over our period of analysis. Figure 6 does so for diesel. In both cases, we can distinguish two periods. The first one from 2001 to mid-2008 is also the period in which the demand for automotive fuels increased. The second period from mid-2008 onward is, on the contrary, the period of sharp decline in consumption (Figure 2). During the first period, the difference between the margins fluctuates around 1 cent per liter. From mid-2008 onward, this difference increased notably with the exception of the period September-December 2012, in which the gross retail margins were in Spain below those in Europe. This anomaly was due to sharp fall in prices on Mondays (the "Monday effect"). Oil operators systematically decreased retail prices on Monday to sharply increase them on Tuesday. Monday was the day in which the Ministry of Industry collected data from service stations to report prices to the *Bulletin Petrolier,* the European weekly prices statistic. By dropping retail prices on Monday, oil companies would have tried to distort the Spanish position in the European raking of fuel prices, according to the CNE. The CNE also points out that Repsol set prices on the "Monday effect" basis. The rest of traditional oil companies would have followed Repsol's pricing strategy. The CNE decided to initiate an investigation for suspected anticompetitive behavior. The "Monday effect" disappeared in 2013 (CNE, 2013).

In order to further investigate the relationship between the Spanish pre-tax retail price and the spot price, both for gasoline and diesel, we carry out a regression analysis. Prior to model specification, we examine the nature of the stationary and the cointegration relationship. First, we test the variables SGRP, SDRP, GS (gasoline spot price) and DS (diesel spot price) for stationarity using the augmented Dickey –Fuller (ADF) test for unit roots. To carry out the ADF test, the following regression is estimated for each variable:

$$\Delta y_t = \alpha + \beta t + \gamma y_{t-1} + \sum_{i=1}^{k} \delta_i \Delta y_{t-i} + \varepsilon_t \qquad (1)$$

where *t* is the linear time trend, Δ is the first difference operator, ε is the random error term, and k is the order of the augmentation to eliminate the correlation in the residual of the regression, which is empirically determined by using information criteria, such as Akaike (AIC) or Schwarz (BIC). The ADF test consists on testing the presence of a unit root, i.e. $\gamma = 0$, by comparing the t-statistics for γ against a non-standard distributions (Fuller, 1976 and Dickey and Fuller, 1981).

In addition, we test for breaks in the time series of gross retail margins, both for gasoline and diesel. Our objective is to confirm that there was a discrete change in behavior by mid-2008. We test for breaks by computing the Chow test statistic for each date in our samples (Andrews. D.W.K, 1993; Stock and Watson, 2003). That is, for any hypothesized break date k in the period of analysis, we consider the regression:

$$margin_t = \alpha + \beta_t D_t(k) + \varepsilon_t \qquad (2)$$

where $D_t(k)$ is a binary variable equal to zero before the break date k ($t<k$) and one after. The hypothesis of a break at date k is tested using an F statistic that test the hypothesis that β_t is equal to zero, which means that there is no break at date k. The break point is determined by the largest of the computed F statistics, which indicates that there is a break point in June 2008[11], when the gross retail margin in Spain jumped clearly above the European average one, both for gasoline and for diesel. Therefore, we test the variables SGRP, SDRP, GS and DS for stationarity using all data and distinguishing two different periods. The first one goes from January 2001 to May 2008 and the second one ranges from June 2008 to May 2015.

Table 2 shows the results of test for stationary of our four variables of interests and their first differences using the ADF statistic. Cleary, all the variables have a unit root while their first differences are stationary with respect to all data and both periods. In particular, the four variable are integrated of order one or $I(1)$ without intercept and trend.

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[11] The computations are carried out with the package strucchange 1-5.1 (Zeiles et al, 2002) in the R system for statistical computing (R Development Core Team, 2015, version 3.2.1)

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In this case, SGRP and GS, on the one hand, and SDRP and DS, may be cointegrated, which would mean the existence of a stable long-run economic relationship between the retail and the spot price, both for gasoline and diesel in Spain. In order to test for cointegration, we first assume that there is a stable long-run relationship between the Spanish net retail price and the spot price for gasoline and diesel as follows[12]:

$$SGRP_t = \beta_0 + \beta_1 GS_t + \varepsilon_t \quad (3)$$

$$SGRP_t = \beta_0 + \beta_1 GS_t + \beta_2 D_t + \varepsilon_t \quad (4)$$

$$SDRP_t = \beta_0 + \beta_1 DS_t + \varepsilon_t \quad (5)$$

$$SDRP_t = \beta_0 + \beta_1 DS_t + \beta_2 D_t + \varepsilon_t \quad (6)$$

where D_t is a dummy variable that takes value 1 from June 2008 to May 2015 and 0 otherwise. Then, we test the hypothesis that the residual from the OLS estimate of Eqs. (3), (4), (5) and (6) are not stationary. We have carried out the analyses using the ADF test without and with break point (BP), both for gasoline and diesel. Results from Table 3 show that the hypothesis is rejected in all cases. So, the variables SGRP and GD, on the one hand, and SDRP and DS, on the other hand, are cointegrated. In addition, Table 3 shows the estimated long-run relationship between the retail and the spot price, both for gasoline and diesel.

[12] Spain is a small country relative to the world market in trading crude oil, gasoline and diesel. This assumption ensures that causality, if present, is in one direction, i.e. from the world market to the local market.

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Provided that the coefficient of the spot price is equal to one, the estimated gross margin for the first period would be equal to the estimated intercept and that for the second period would be equal to the estimated intercept plus the estimated coefficient of the dummy variable (D_t). As the null hypothesis that β_1=1 (see Table 3) cannot be rejected when the long-run relationship between the retail and the spot price is analyzed properly (i.e. taking into account the break point in May 2008), the estimated gross margin per liter sold would be 11.323 cents per for gasoline and 11.817 cents for diesel for the first period, and 14.26 cents per liter for gasoline and 15.205 cents for diesel for the second period[13]. In other world, the gross margin per liter was much higher during the second period than during the first one, both for gasoline and for diesel, as the highly statistically significance of the coefficient of the dummy variable shows in all cases. This difference in the gross margins between the first and the second period goes hand in hand with the relative increase of the Spanish retail prices compared to the European average ones from mid-2008 onward, which do not appear to be cost based, as the Spanish refining or retail sector have not faced any specific cost sock.

Next, we analyze the effect that the evolution of gross retail margins (per liter) and consumption have had on Spanish oil retail sector profits. Specifically, we have estimated the "total gross retail margin" on a monthly basis as the sum of the gasoline total gross retail margin, which is equal to the gross retail margin per liter sold multiply by the consumed liters, and the diesel total gross retail margin, calculated in the same

[13] We have calculated these mean gross margins from our data set. These are: 11.576 cents for gasoline and 11.903 cents for diesel for the first period and 14.682 cents for gasoline and 15.352 cents for diesel for the second period. Therefore, these margins are virtually the same than those estimated on the basis of the regression analyses.

way as for gasoline. Figure 7 show the evolution of the total gross retail margin between January 2001 and May 2015. The retail margin (per liter) increase between mid-2008 and May 2015 has allowed the oil retail sector slightly increase their profits, despite the sharp decline in consumption.

The gross margin increases may have opened the door to prices differences among service stations. Such differences have traditionally been rather small in Spain (CNE, 2012). However, they have increased notably during the last years. As such, the CNMC points out that in February 2014 retail prices at independent service stations were, on average, 3 and 4 cents below those at branded stations for gasoline and diesel, respectively. Prices at hypermarkets services stations were even 1.8 cents below retail prices at independent stations. According to our calculus, the gasoline (diesel) gross margin per liter sold was 5.0 (4.03) cents higher in Spain than in Europe that month. Differences in consumers search costs (and brand loyalty) and between oil operators' pricing strategies would explain why these prices differences persist over time. As such, branded stations would attract consumers with higher search costs, who probably value fuel brand as high quality and are little concerned about prices, whereas independent service stations would attract consumers with low search costs and more concerned about prices (Lewis 2008, Hastings, 2004). As a result, independent service stations would compete more aggressively on prices and branded station on "quality".

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Please Insert Figure 7

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Conclusions.

This paper analyzes the competitive functioning of the Spanish retail automotive fuels market since the beginning of this century until May 2015. The Spain oil industry is interesting in its owns right, because of the complexity of its process of restructuring, privatization and liberalization. This process was not exclusively directed towards creating competition in the sector; it also aimed to ensuring the stability of the industry by protecting the traditional refiners' status quo after the abolishment of the state monopoly the setting up of a "national champion", Repsol, structured similarly to international oil companies. Although the refiners have lost market share in the retail sector with the arrival of new operators, a high horizontal and vertical concentration currently persist. This has raised continuous concerns about the non-competitive market behavior of the oil operators in Spain.

Our empirical results lead us to distinguish between two different periods within our period of analysis. During the first period, from January 2001 to mid-2008, total demand for automotive fuels increased constantly and pre-tax retail prices and margins were slightly above the European average ones. During the second one, from mid-2008 to May 2015, on the contrary, pre-tax retail prices were in Spain well above those in Europe, and gross retail margins per liter sold jumped clearly above European levels whereas the consumption of automotive fuels dropped sharply. Our analyses have shown that this behavior of prices and margins is consistent with some oil companies exercising market power. More specifically, oil operators have been able to increase their margins per liter sold during the recessive period of the Spanish economy which have allowed them to "offset" the drop in consumption. As a result, the total retail gross margin has remained relatively stable from 2001 onward. In a dynamic and competitive market, a sharp decline in consumption is usually accompanied by a fall in relative prices and margins; just the opposite that has happened in the Spanish retail automotive fuels market. In addition, there has not been any supply shock, such refinery outages or pipeline ruptures, in the Spanish oil industry that may explain the disparity in prices and margins between Spain and Europe from mid-2008 onward. The gross margin increases, however, have opened the door to prices differences among service stations.

The Spanish oil case clearly shows how difficult it is to achieve dynamics and competitive markets, even many years after their formal liberation, when the liberalization at aimed at creating "national champions" and at ensuring the stability of the traditional oligopolistic status quo. A very pro-competitive market approach by Sectoral Regulators and by Antitrust Authorities would be needed to create "real" competitive markets in these formally liberalized sectors. In fact, in the last year the Spanish Antitrust Authority is playing an active role in monitoring the sector, as well as in detecting and correcting anticompetitive behaviors in the oil sector, which is costly. Indeed, the CNMC has fined major oil operators for horizontal and vertical anticompetitive practices. However, this has increased litigation between major oil operators and the Spanish Antitrust Authority dramatically. In addition, the CNMC has proposed many measures to lower entry barriers and to promote competition both in the retail and in the wholesale sector; many of them have been approved and implemented by the Spanish sector. These measures are aimed at curtailing major operators' market power, thus reducing price-cost markups. For example, in the wholesale sector new obligations have been established for equal access to certain infrastructure such as transparency requirements for available capacity. In the retail sector, urban planning restrictions to open new service stations have been reduced and exclusive contracts between oil operators and stations have been limited to three years. Furthermore, market operators with a market share of over 30% in a province will not be able to open new stations and oil operators can no longer recommend the retail prices, directly or indirectly, to service stations. We will see in the future in these measures, which results may take time to materialize, are successful in enhancing competition in the Spanish automotive fuels market.

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Table 1. Evolution of the number of service stations in Spain by brand: 1995-2014

Operator	1995		2001		2008		2014	
	Number of Outlets	**Market Share (%)**	**Number of Outlets**	**Market Share (%)**	**Number of Outlets**	**Market Share (%)**	**Number of Outlets**	**Market Share (%)**
Repsol	3,500	55.32	3,704	47.50	3,590	41.46	3,615	36.96
Cepsa	1,500	23.71	1,437	18.43	1,528	17.77	1,470	15.03
BP	400	6.32	582	7.46	642	7.15	674	6.89
Shell	120	1.90	278	3.57	-			
Total	127	2.01	187	2.40	-			
Galp	120	1.90	187	2.40	230	2.64	566	5.79
Meroil	70	1.11	184	2.36	192	2.20	166	1.70
Disa	100	1.58	140	1.80	500	5.75	387	3.96
C.Oil	25	0.40	0	0.00	-			
Agip	75	1.19	127	1.63	318	3.66	74	0.76
Petrocat	50	0.79	69	0.88	66	0.59	63	0.64
Avanti	45	0.71	61	0.78	-			
Esso	25	0.40	67	0.86	82	0.94		
Esergui	30	0.47	65	0.83	105	1.21	132	1.35
Tamoil	20	0.32	43	0.55	35	0.40	23	0.24
Kuwait P.	20	0.32	17	0.22	44	0.51	53	0.54
Texaco	15	0.24	50	0.64	-			
Saras	0	0	0	0	60	0.69	114	1.17
Red Tortuga							83	0.85
Independent	85	1.34	600	7.69	1,308	15.03	2,362	24.15
TOTAL	6,327	100	7,798	100	8,700	100	9,782	100.00
C3 refiners[a]		85.35		73.39		66.38		58.87
HHI[b]		3,683		2,750		2,374		2,280

[a] C3 refiners is the sum of the Spanish-based refiners' market share; [b] HHI is the Herfindahl-Hirsmcham Index.
Source: Enciclopedia Nacional del Petróleo, Petroquímica y Gas, 1995-2014

Table 2: ADF unit root tests

Gasoline	*SGRP*	*ΔSGRP*	*GS*	*ΔGS*
All data	1.6943	33.9196** -8.569**	2.515	38.3927** -8.763**
First period	0.5154	19.6743** -6.273**	0.7158	21.8619** -6.611**
Second period	3.9124	27.6669** -7.419**	3.5654	27.9169** -7.459
Diesel	***SDRP***	***ΔSDRP***	***DS***	***ΔDS***
All data	1.7431	25.6492** -7.161**	1.6596	26.9899** -7.347**
First period	2.0865	13.8816** -5.213**	1.7917	18.7802** -6.100**
Second period	1.7697	22.357** -6.647**	1.3298	24.9496 ** -7.017**

Augmented Dickey-Fuller test statistic using the Akaike information criteria. We denote ** to indicate the rejection of the null hypothesis (the variable has a unit root) at a 1% significance level using the critical values tabulated in Dickey and Fuller (1981). The second statistic for the first difference of the variables corresponds to the sample t-ratio to test the null hypothesis with the standard Student t distribution.

Table 3: The long-run equations estimated by OLS. Cointegrated test

	Gasoline[a]		**Diesel**[a]	
	Without BP	**With BP**	**Without BP**	**With BP**
cons	10.037(0.536)**	11.323(0.587)**	10.482(0.551)**	11.817(0.464)**
GS	1.081(0.011)**	1.009(0.021)**		
DS			1.077(0.014)**	1.003(0.014)**
D		2.927(0.655)**		3.388(0.501)**
Adj-R^2	0.983	0.988	0.987	0.993
D-W	0.938	1.145	0.769	1.146
$\beta_1=1$[b]	5.411**	0.441	5.520**	0.211
ADF[c]	18.6205** -6.086**	21.079** -6.478**	12.4182** -4.976**	17.605** -5.931**

[a]Estimated coefficients of the long run equations. Newey & West heteroskedasticity and autocorrelation consistent standard errors are in parenthesis.
[b] t-Statistics,$(\beta_1-1)/s$, to test H_0: $\beta_1=1$ for the long-run equation. We denote ** to indicate the rejection of the null hypothesis at a 1% significance level.
[c]Augmented Dickey-Fuller test statistics using Akaike information criterion. We denote ** to indicate the rejection of the null hypothesis (the variable has a unit root) at a 1% significance level on the basis of the critical values by Dickey and Fuller (1981) . The second statistic of the variables corresponds to the sample t-ratio to test the null hypothesis with the standard Student t distribution.

Figure 1: The Spanish distribution system for oil products

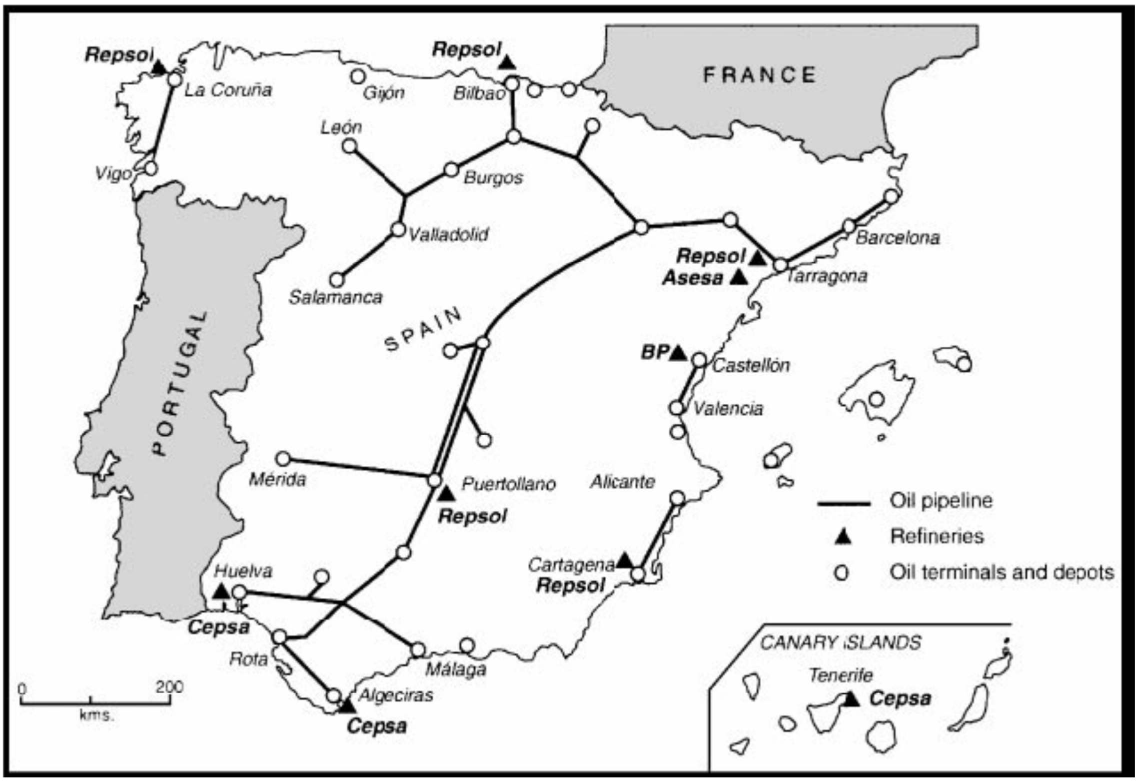
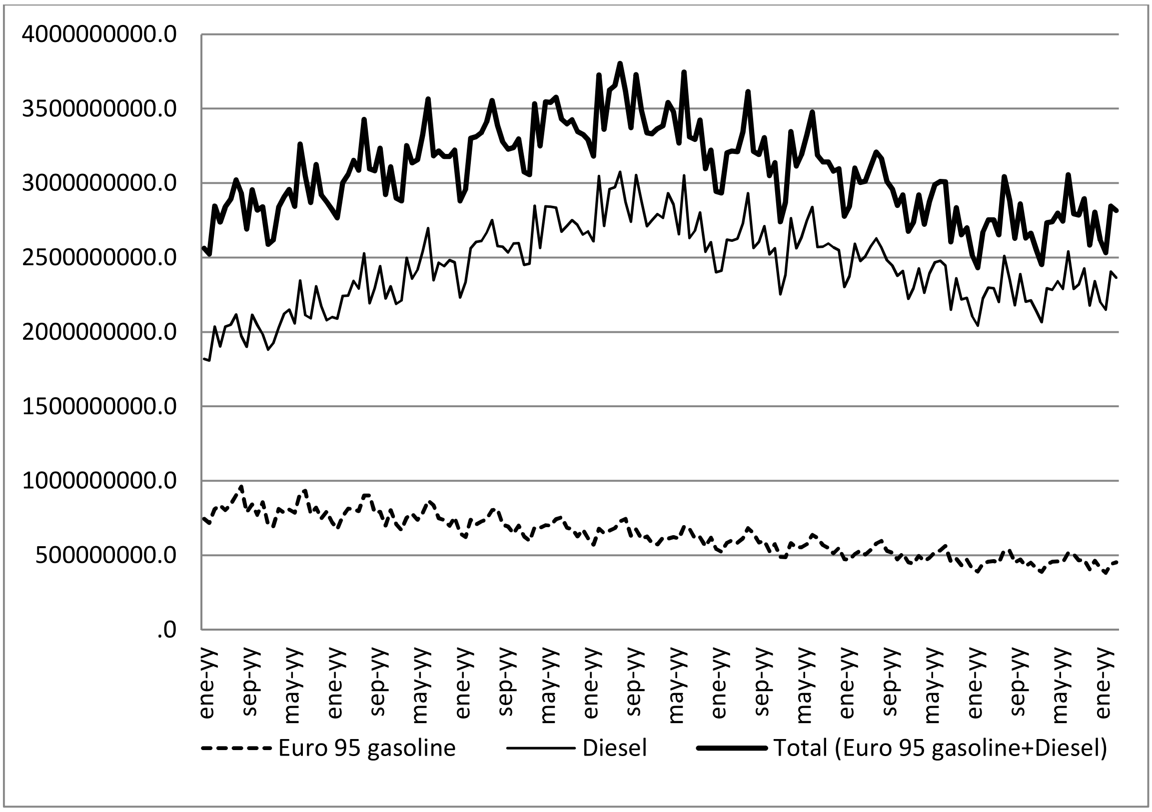
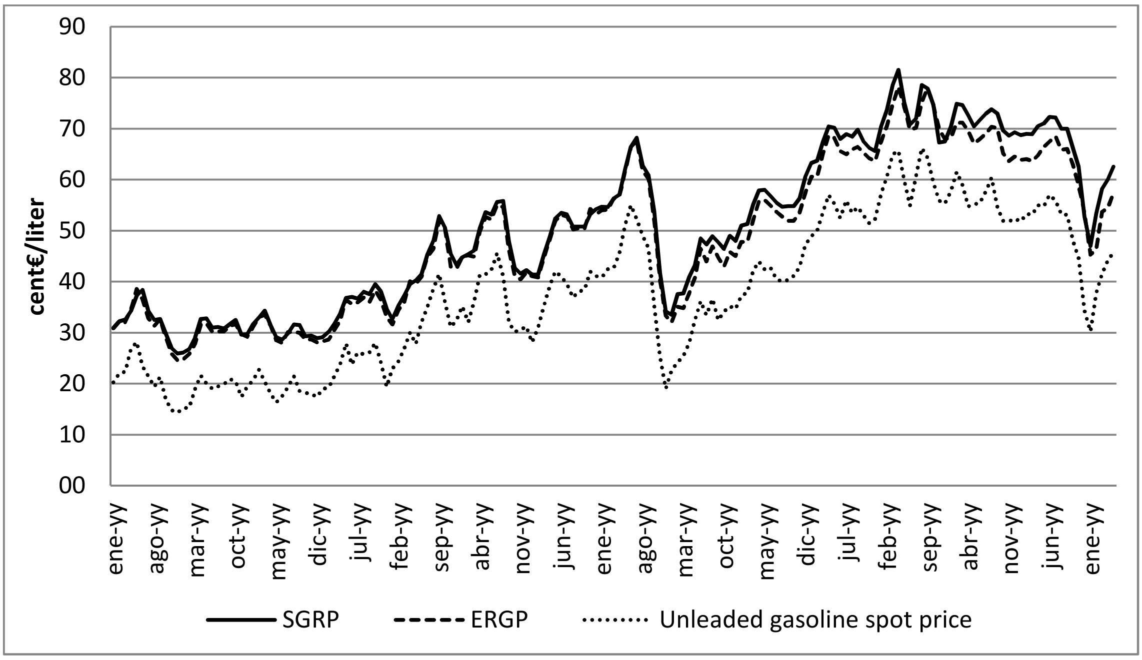


Figure 2. Demand for automotive fuels in Spain (liters)



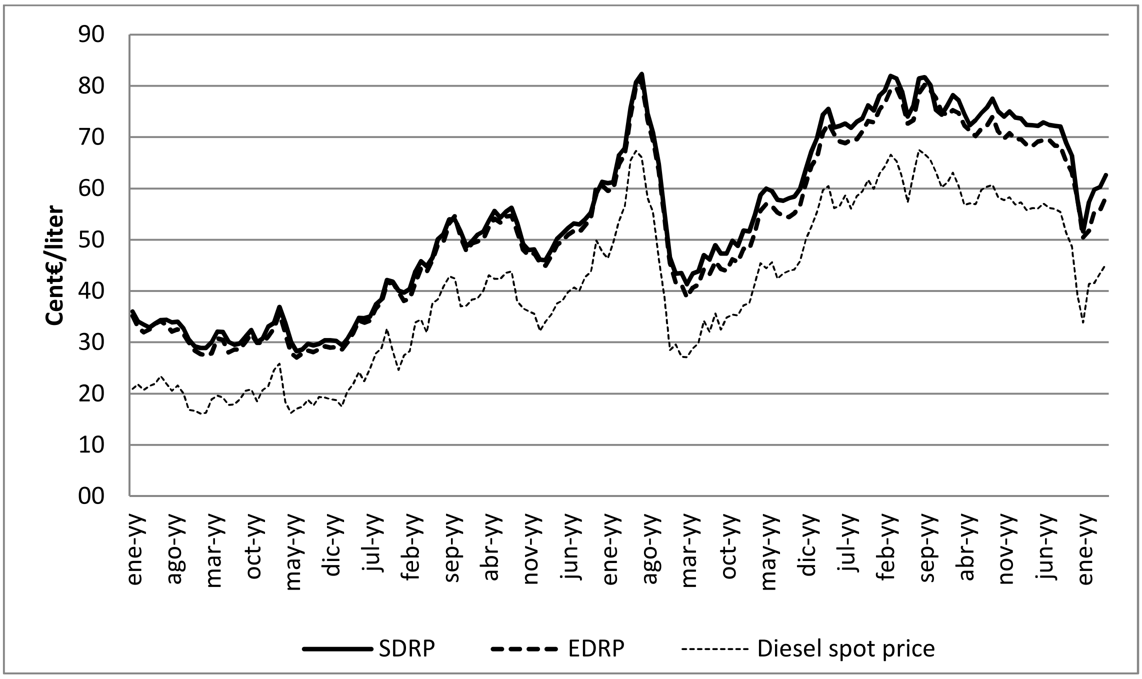
Source: CORES

Figure 3. Time series of gasoline prices



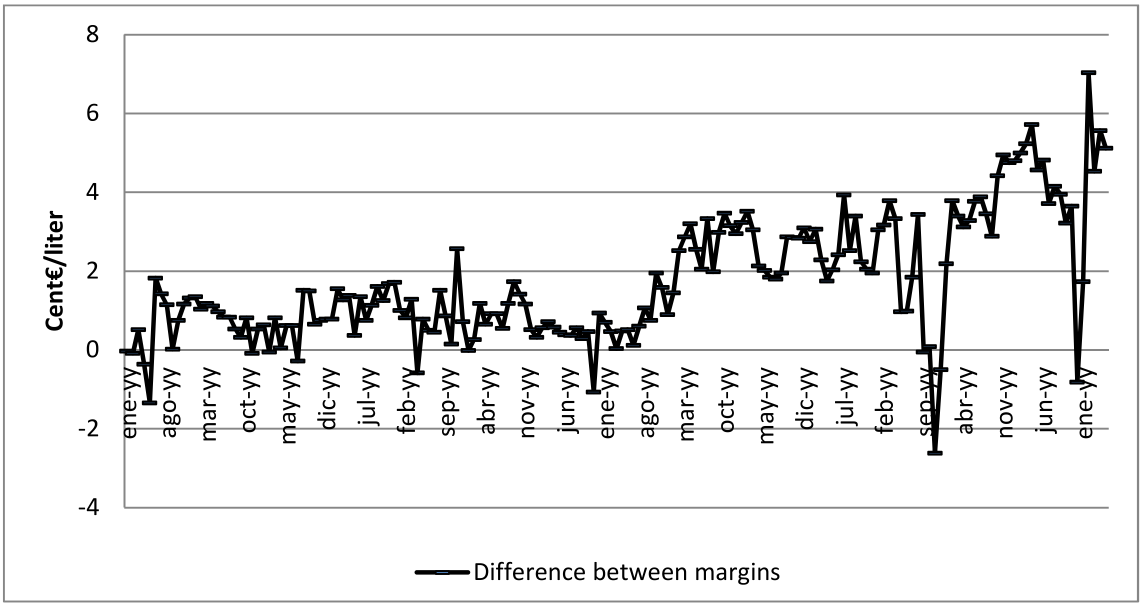
Source: Ministry of Industry
SGRP = Spanish gasoline retail price
ERPG = European gasoline retail price

Figure 4. Time series of diesel prices



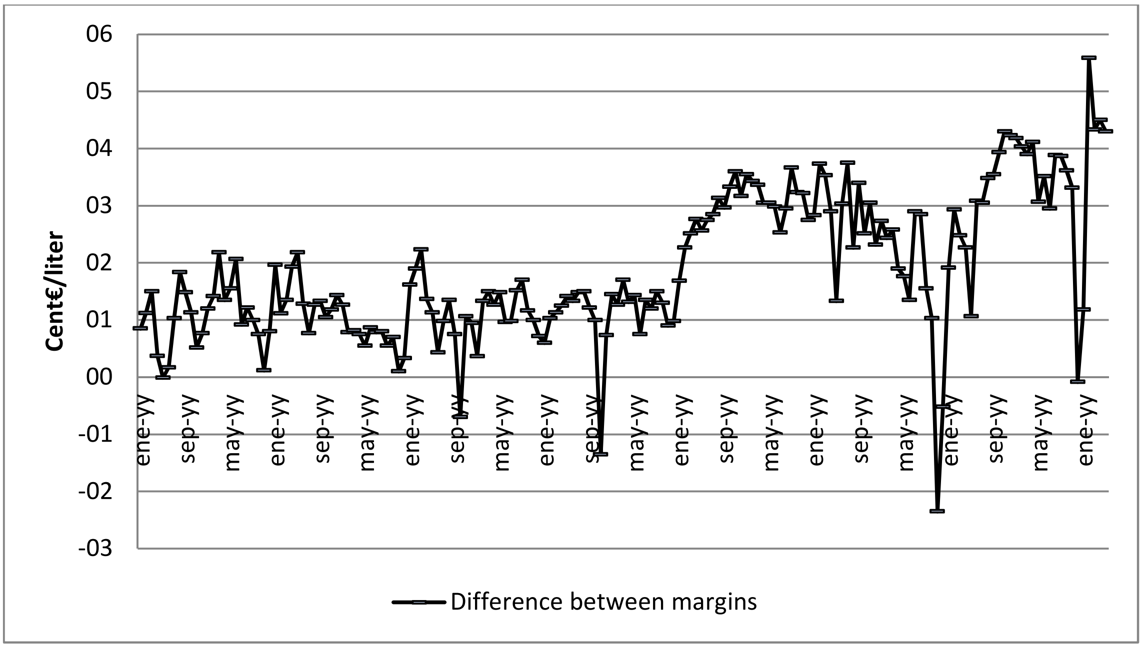
Source: Ministry of Industry
SDRP = Spanish diesel retail price
EDRP = European diesel retail price

Figure 5. Differences in gross retail margin between Spain and Europe on gasoline



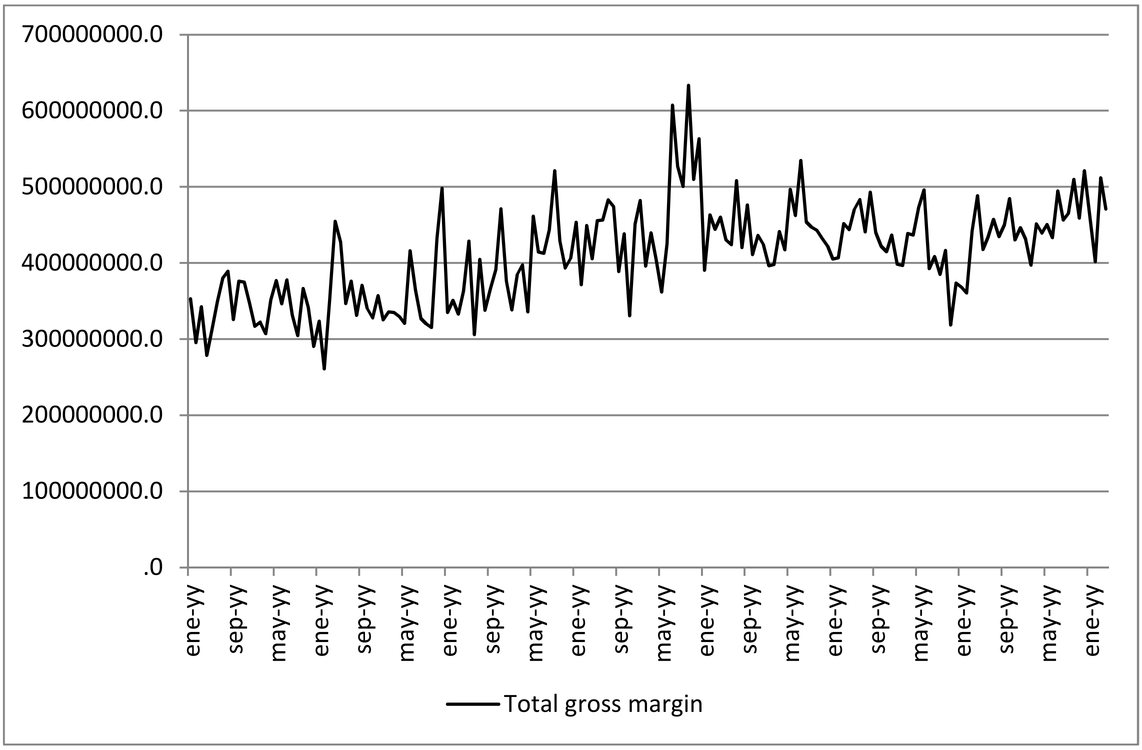
Source: Ministry of Industry

Figure 6. Differences in gross retail margins between Spain and Europe on diesel



Source: Ministry of Industry

Figure 7. Total retail gross margin (euros)



Source: Ministry of Industry and Cores

The deflationary effect of oil prices in the euro area

César Castro*[1], Miguel Jerez†[2] and Andrés Barge-Gil‡[2]

[1]Department of Economics, University of Salamanca, Spain.
[2]Department of Economic Analysis II, Universidad Complutense de Madrid, Spain

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Abstract

The inflationary effect of oil price has been widely examined by academic literature. Nowadays, the main concern in the euro area (E.A.) is its deflationary effect. In this paper we propose a method to evaluate the effect of oil price changes on inflation as well as an indicator of inflation adjusted for the short-term effect of oil prices, which is aimed to assess the risk of deflation in real time. We illustrate the practical applications of these tools by predicting the evolution of inflation in the E.A., conditional to different scenarios of oil price deflation. Our main finding is that no deflationary scenario for oil prices results in a negative inflation rate forecast for October 2016, despite oil price variation accounting for 25% of the variance of changes in inflation.

Keywords. Inflation, Deflation, Oil price, Euro area, Forecasts.

*Corresponding author. E-mail: ccastrorozo@gmail.com
†E-mail: mjerezme@ucm.es
‡E-mail: abarge@ccee.ucm.es

1 INTRODUCTION

The relevance of oil prices as a source of variations in prices is established since the 1970s. However, in the last two decades several works have documented that this relevance has decreased. Hooker (2002) finds no significant impact of oil prices changes on U.S. inflation, excluding energy products. DeGregorio et al. (2007) document an important reduction in the contribution of oil prices changes on consumer prices, providing evidence for a sample of 34 countries. Blanchard & Galí (2010) find that the inflationary impact of crude costs decreased since mid 1980s. Kilian (2008c,a) states that the effect of exogenous oil prices shocks on inflation in G7 countries is quite small and highlights its heterogeneity across countries. Álvarez et al. (2011) find that the contribution of oil price changes is limited, but still constitutes a major driver of inflation variability in Spain and the euro area, mainly through direct effects.

Several reasons have been proposed to explain this loss of relevance (e.g., DeGregorio et al. (2007); Blanchard & Galí (2010)): higher energy efficiency of production processes, relevance of globalization or changes in the conduct of monetary policy.

The emphasis of academic analyses also changed. Previous studies traditionally focused in assessing the inflationary effect of the increases in oil price. However, the main concern in the recent months is the risk of a deflation spiral unchained by oil prices reductions.

The main contributions of this paper are: (i) a method to assess the effects of oil prices changes in inflation under different oil price scenarios and (ii) a model-based indicator of inflation adjusted for the short-term effect of oil prices, being this indicator a potentially useful tool to track in real time the risk of deflation. We illustrate the practical application of these tools by means of a simulation analysis of the risk of deflation in the euro area (E.A.).[1].

To this end, we first fit a time series model relating the annual variation rates of inflation and oil price. Its dynamic structure implies that the price of crude oil in any given month affects consumer prices in the same month and the month after, with no feedback in the opposite direction of Granger causality. We provide several justifications for this assumption, as well as a Granger-causality test for the E.A.

With this model we: (a) compute twelve-months ahead forecast for inflation in

[1]E.A. refers to the respective country compositions at a specific point in time: E.A.11-2000, E.A.12-2006, E.A.13-2007, E.A.15-2008, E.A.16-2010, E.A.17-2013, E.A.18-2014, and E.A.19-2015. Euro area is the official name for the Eurozone

the E.A., conditional to different scenarios of oil price deflation and (b) estimate which part of the recent evolution of consumer prices can be attributed to changes in oil prices. This analysis incorporates two novelties: an interpolation method to compute forecasts conditional to any predetermined terminal value using a fixed-interval smoother (see Anderson & Moore (1979)), and the procedure developed by Casals et al. (2010), which computes the contribution of each input to the output for any model in transfer function form.

The main results of this analysis are: (a) negative inflation is not expected for the twelve-months-ahead forecasts in any of the three scenarios, (b) the short-time effect of oil on consumer prices is important, as it accounts for 25% of the variance of changes in inflation so, (c) a spiral of deflation/economic contraction could finally happen if a long period of anemic inflation/deflation affects the consumer expectations and, through them, the economic activity.

The paper is organized as follows. Section 2 discusses the methodological foundations, describes the data and provides a preliminary exploration of their dynamic properties. Section 3 describes the model-building process and Section 4 discusses the empirical results. Finally, Section 5 provides some concluding remarks.

2 METHODOLOGY

2.1 Methodological issues

Our analysis concentrates in the effect of oil prices over inflation in the E.A. An important issue when developing this analysis is to consider the possibility of a feedback relationship, with inflation explaining oil prices.

There is a widespread agreement in the current literature that oil price should be considered endogenous with respect to macroeconomic aggregates, in particular with respect to U.S. GDP growth (see, e.g., Barsky & Kilian (2004); Kilian (2008b); Hamilton (2009); Kilian (2014)). This idea is based in the weight of U.S. GDP growth on the global demand, including oil demand, and hence on oil prices.

On the other hand, the Granger (G- causality) test has often been used to test whether U.S. inflation help in predicting oil price changes. G-causality is usually not found after 1975 (Hooker (1996), Gillman & Nakov (2009), Alquist et al. (2013)). [2]

[2] Alquist et al. (2013) find, however, that U.S. inflation G-causes oil prices if 1973 and 1974 are included in the analysis

The E.A. shows three important differences with U.S.: its lack of internal oil production, its smaller economic size[3] and its lower influence through monetary policy. Accordingly, we will first assess whether E.A., with 13% of global oil consumption is large enough to determine oil prices[4]. In comparison, the consumption in U.S. has been 23%. To this end, in the next Sub-section we test for linear G-causality, finding no significant influence of E.A. inflation on oil prices.

Building on this negative result, we use in our analysis a transfer function (TF) specification (Box et al. (1994)), relating oil price (cause) to E.A. inflation (effect) instead of the vector autoregressive (VAR) framework model (e.g., Hamilton (1983); Jiménez-Rodríguez & Sánchez (2005); Kilian (2009); Blanchard & Galí (2010)).

The main reason for this choice is that, if no relation exists between lagged inflation and current oil price, then the bidirectional VAR representation looses its main advantage when compared to the unidirectional TF model. On the other hand, the TF model has two compelling advantages for our analysis.

First, the TF is a structural model, allowing one to attribute the contemporary correlation to a specific causal direction, while the reduced-form VAR model captures this correlation in a non-causal way. This is specially important in our analysis because the contemporaneous correlation between oil price changes and inflation: (a) has been shown to be unidirectional (Kilian & Vega (2011)), (b) is much stronger than the lagged ones, so it (c) has a strong contribution to the point forecasts and fitted values for inflation employed in our analysis.

Second, inflation displays a strong seasonal fluctuation which is easier to capture in the ARIMA model for the errors of a TF than in a VAR framework.

2.2 The data

In this Sub-section, we provide a exploratory analysis of the data that we will model later.

We will denote by O_t^{EUR} the nominal price of Brent in € per barrel at month t.[5]

[3]In terms of its share of global GDP in PPP in 2014, the euro area is the worlds third-largest economy (12.2%), after the United States (15.9%) and China (16.6%).

[4]This percentage has been obtained as the mean participation between 1996 and 2014 of the oil consumption of 11 European countries (Austria, Belgium, Finland, France, Germany, Greece, Ireland, Italy, Netherlands, Portugal and Spain) in the total world. These data come from the British Petroleum Statistical Review of World Energy 2014 http://www.bp.com.

[5]We consider the oil price in U.S. dollar downloaded from the U.S. Energy Information Administration (EIA) web page http://www.eia.gov and use the monthly average exchange rate published

For the euro area inflation P_t^{EA} we consider the Harmonized Index of Consumer Price (HICP, source: http://ec.europa.eu/eurostat). In both cases the observation frequency is monthly and the sampling period runs from January 1996 to October 2015.

Building on this data we computed the annual percent variation rates, defined by:

$$r^{12}(x_t) = \left(\frac{x_t}{x_{t-12}} - 1\right) \times 100$$

Hence these basic variables often appear transformed in annual percent rates: $r^{12}(O_t^{EUR})$ for annual percent change in oil prices, and $r^{12}(P_t^{EA})$ for inflation in the E.A.

The profile of these series is shown in Figure 1. The upper panel allows us to identify several oil price periods: First, the negative shock started in 1997, caused mainly by falls in oil market-specific demand following Asian crisis of 1997-1998. This effect was accompanied by positive rebounds started in late 1998 that reaches its maximum in February 2000. Second, several sustained positive rates between late 2002 and early 2008, driven by global aggregate demand originates in a stronger economic growth, especially in Asian. This effect was reversed by a sharp drop in prices associated with the global crisis of 2007-2009. This effect was also accompanied by positive rebounds started in 2009 that reaches its maximum in December 2009. Finally, there has been a sustained fall in prices since late 2009, associated with a strong global supply and a weak global demand.[6]

As expected, these series display changes in the mean, so their stationary transformation would be a first-order difference.[7] Accordingly, the resulting variables can then be interpreted as the monthly acceleration in the inflation rate and annual rate of growth of oil prices, respectively. Figure 2 shows the profile of these series[8].

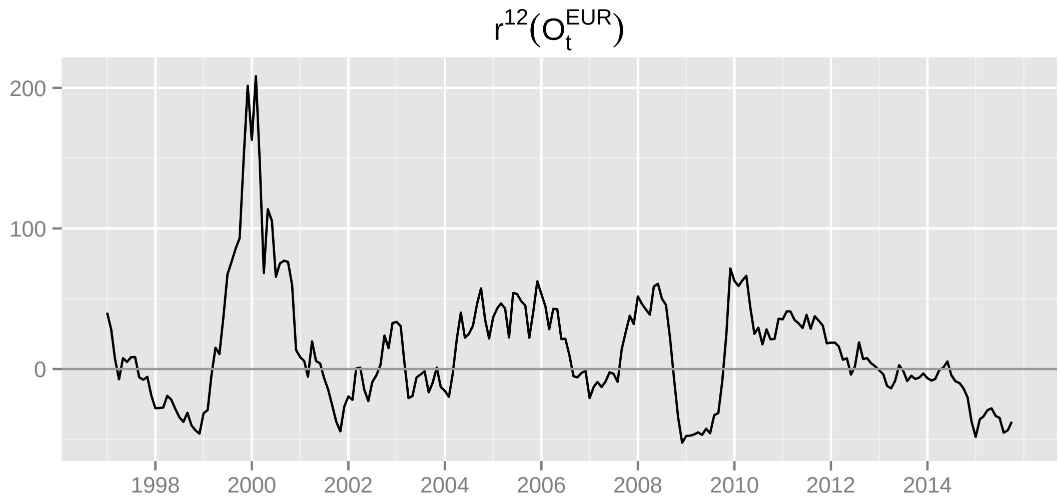
Table 1 displays some descriptive statistics for the stationary transform. The $p-values$ in the table show that 1st-differenced transformation of annual rates

by the OECD http://www.stats.oecd.org to calculate the equivalent value in euros.

[6]For details see e.g., Kilian (2009).

[7]In our opinion, O_t^{EUR} could either be I(1) or display a weak seasonality which is buried by its high volatility. However, we work with the same transformation in both variables because the underlying assumption is that oil prices affect consumer prices, so annual inflation must be affected by the annual growth rate of oil prices, no matter that the minimum-order stationary transform for each series can be different.

[8]$\nabla = (1-L)$ is the difference operator, such that $\nabla\omega_t = \omega_t - \omega_{t-1}$.



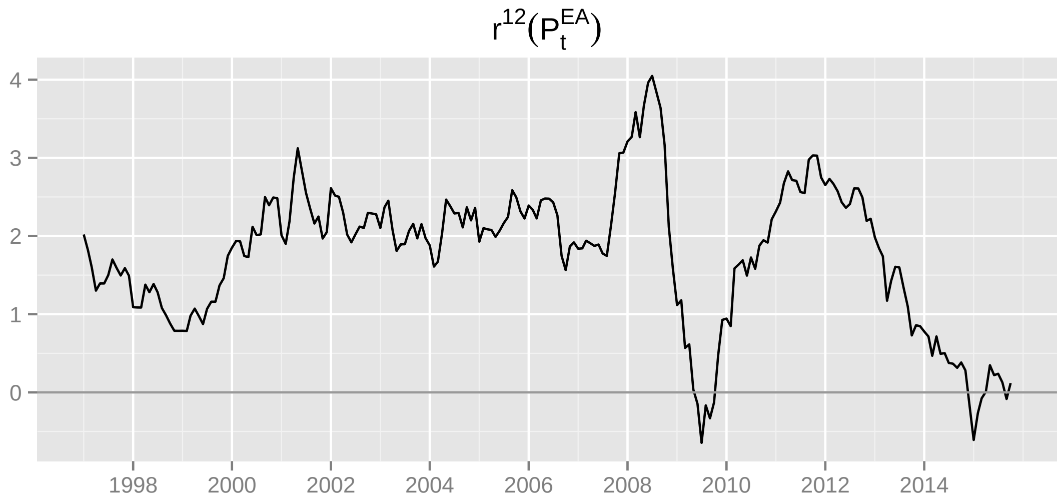


Figure 1: Annual percent changes for Brent Price in € per barrel, $r^{12}(O_t^{EUR})$ and inflation in the euro area, $r^{12}(P_t^{EA})$. Source: Eurostat and EIA.

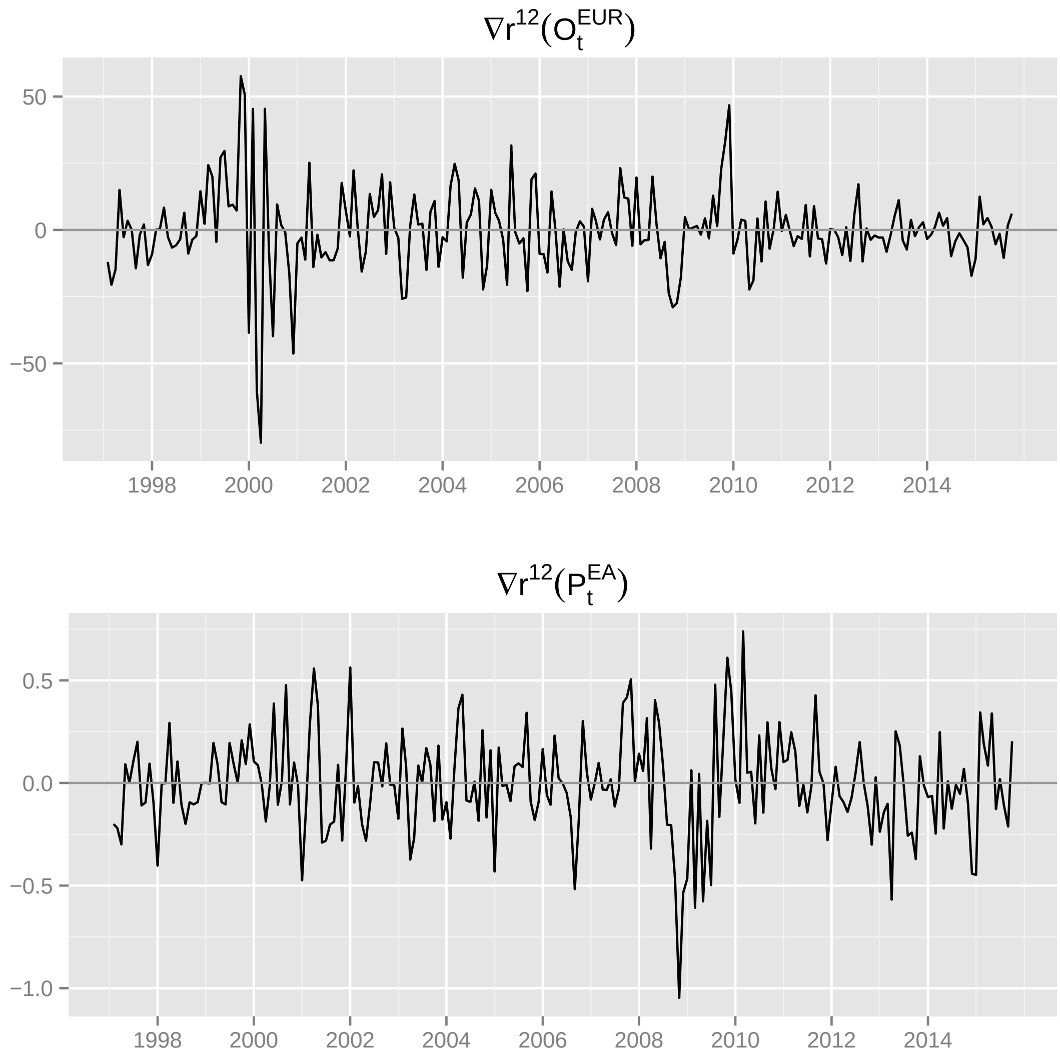


Figure 2: Stationary series for Brent Price in € per barrel, $\nabla r^{12}(O_t^{EUR})$ and inflation in the euro area, $\nabla r^{12}(P_t^{EA})$. Source: Eurostat and EIA.

assure the stationarity. Note that the volatility of $\nabla r^{12}(O_t^{EUR})$ is two orders of magnitude higher than that of the $\nabla r^{12}(P_t^{EA})$.

Table 1: Descriptive statistics for the stationary series for Brent Price in €, $\nabla r^{12}(O_t^{EUR})$ and inflation in the euro area, $\nabla r^{12}(P_t^{EA})$.

	$\nabla r^{12}(O_t^{EUR})$	$\nabla r^{12}(P_t^{EA})$
Mean	-0.34	-0.01
Std. Dev.	15.89	0.24
Minimum	-79.75	-1.05
Maximum	57.63	0.74
p-value ADF	0.01	0.01
p-value KPSS	0.10	0.10

2.3 Granger causality test

We will now perform the standard G-causality test (see Granger (1969)) for a fitted VAR model to assess whether (a) past values of oil prices changes in € help in predicting current inflation changes in the E.A. and/or b) there exists the corresponding inverse G-causality effect. If causal effects in Granger sense operate in both directions, then both variables would be endogenous and a vector autoregressive (VAR) model would be needed to obtain consistent estimates for the corresponding dynamic feedback structure.

The G-causality test is implemented by the regressions:

$$\nabla r^{12}(P_t^{EA}) = c^1 + \alpha_1 \nabla r^{12}(P_{t-1}^{EA}) + \beta_1 \nabla r^{12}(O_{t-1}^{EUR}) + \mu_t^1$$

$$\nabla r^{12}(O_t^{EUR}) = c^2 + \alpha_2 \nabla r^{12}(O_{t-1}^{EUR}) + \beta_2 \nabla r^{12}(P_{t-1}^{EA}) + \mu_t^2$$

Table 2 shows the $p-$values for each $F-$test with the lag order p =1 chosen according to the Schwartz Information Criterion (SIC). Due to the differencing used to induce stationarity on the series, that is, the monthly change in annual rates, the lag order p=1 implies effects longer than a year. We do not find evidence of G-causality from E.A. inflation to oil prices, although we find very strong evidence (at 1% significance) that $\nabla r^{12}(O_t^{EUR})$ Granger-cause $\nabla r^{12}(P_t^{EA})$. The replication of this exercise for the U.S. (results available upon request to the authors), shows a p-value of 0.0877 when analyzing G-causality from U.S. inflation to oil prices in dollars. This results supports the view that the relationship between oil prices and inflation is very different between E.A. and U.S. and advise against using our methodology to analyze the relationship between U.S. inflation and oil prices.

Table 2: p-values for linear G-Causality test. The test is calculated with a VAR model. The *lag* order has been selected according to the Schwarz Information criterion (SIC). One/two/three asterisks denote significance at the 10%, 5% and 1% levels, respectively.

lag	$\nabla r^{12}(P_t^{EA}) \nrightarrow \nabla r^{12}(O_t^{EUR})$	$\nabla r^{12}(O_t^{EUR}) \nrightarrow \nabla r^{12}(P_t^{EA})$	
1	0.356480	0.000002	***

3 MODELS

3.1 ARIMA Models

The main purpose of our analysis consists in modelling the relationship between the inflation rate in the euro area $\nabla r^{12}(P_t^{EA})$ and the annual percent growth of Brent prices in €, $\nabla r^{12}(O_t^{EUR})$. The basic shortcoming of this approach is that the world market is quoted in US$, so the latter variable confounds the effects of oil price changes with those due to fluctuations in the exchange rates.

To solve this issue we will take into account that $O_t^{EUR} = O_t^{US\$} \times ER_t$, where $O_t^{US\$}$ denotes the nominal prices of Brent in US$ and ER_t denotes the exchange rate (€/US$) at month t, so that the effect of oil prices changes in US$ are separated from the effect of exchange rate variations.

To accomplish the analysis we start by fitting ARIMA models to the annual rates of inflation and Brent prices in € and US$. The main estimation and diagnostic results are summarized in Table 3. These models are used for different purposes, including forecasting and prewhitening, see Box et al. (1994).

Note that the residual standard deviations of the annual rates of Brent prices are two orders of magnitude larger than that of inflation in the E.A. This is a critical feature of these variables which explains, e.g., that: (a) the €/US$ exchange rate is irrelevant to our analysis and (b) the coefficients relating changes in oil prices with changes in inflation are small in absolute terms.

3.2 Transfer function models

We start by modelling the relationship between the inflation rate in the euro area $r^{12}(P_t^{EA})$ and the annual percent growth of Brent prices in €, $r^{12}(O_t^{EUR})$. The

Table 3: ARIMA modelling results corresponding to ARIMA$(3,1,0)\times(0,0,1)_{12}$ process for $r^{12}(x_t)$. The figures in parentheses are the standard errors of corresponding parameters.

Variable	$\nabla r^{12}(O_t^{EUR})$	$\nabla r^{12}(O_t^{US\$})$	$\nabla r^{12}(P_t^{EA})$
ϕ_1	0.048	0.133	0.208
	(0.065)	(0.066)	(0.065)
ϕ_2	-0.087	-0.104	
	(0.065)	(0.066)	
ϕ_3	0.223	0.165	
	(0.065)	(0.066)	
Θ_1	-0.536	-0.547	-0.551
	(0.06)	(0.06)	(0.053)
σ_a	13.614	13.061	0.204
$Q(39)(p$-value)	43.247 (0.16)	49.73 (0.051)	41.096 (0.296)

relationship has been specified by (a) prewhitening both the input and output series using the ARIMA model for the input (see table 3), and then (b) computing the cross-correlation function between the prewhitening values of both variables, which is shown in figure 3.

The profile of the cross-correlations suggests that inflation is positively correlated with the change in Brent prices in the same month and the month before. In the inverse direction of G-causality (i.e., with current inflation affecting future changes in Brent prices) there is not any significant negative correlation. Accordingly, we confirm our previous findings that G-causality goes from changes in Brent prices to inflation.

On the basis of this statistical analysis, our tentative specification was: (a) a relation term where $r^{12}(P_t^{EA})$ is a function of $r^{12}(O_t^{EUR})$ and $r^{12}(O_{t-1}^{EUR})$, combined with (b) an ARIMA$(0,1,1)\times(0,0,1)_{12}$ model for the error, which coincides with the ARIMA specification chosen for the output, see table 3. This specification provides the following estimation results:[9]

$$r^{12}(P_t^{EA}) = (\underset{(9\times10^{-4})}{0.0053} + \underset{(9\times10^{-4})}{0.0044}L)r^{12}(O_t^{EUR}) + \hat{N}_t^P \tag{1}$$

$$(1-\underset{(0.066)}{0.1396}L)\nabla\hat{N}_t^P = (1-\underset{(0.056)}{0.4548}L^{12})\hat{a}_t^P \tag{2}$$

[9]In these equations the letter L denotes the backshift operator, such that for any sequence ω_t: $L^i\omega_t = \omega_{t-i}$, $i = 0, \pm1, \pm2, ..., I$.

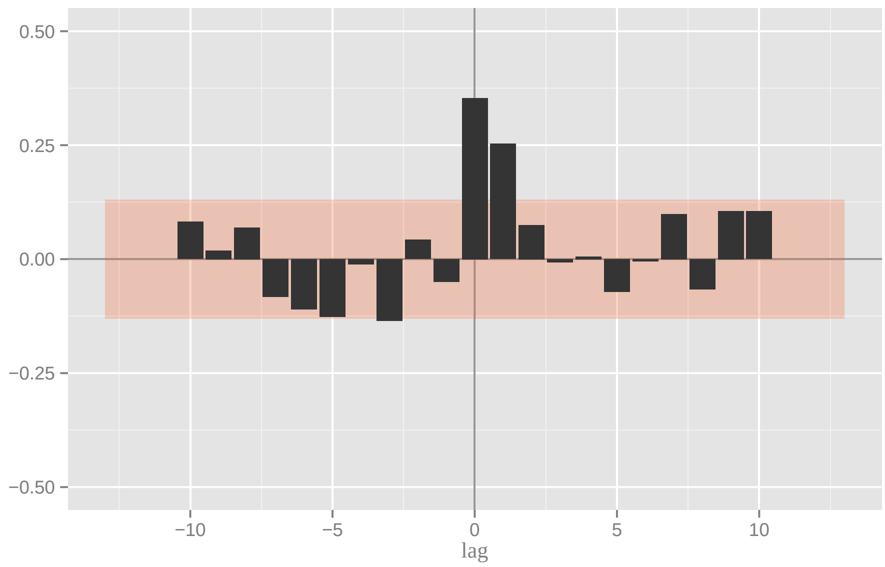


Figure 3: Cross correlations between the prewhitened series of inflation in the euro area, $\nabla r^{12}(P_t^{EA})$ and the lagged annual variation rate of Brent prices in euros. The shaded area is approximate 5% significance limits for each individual correlation. Note that negative lags are actually leads for $\nabla r^{12}(O_t^{EUR})$.

$$\hat{\sigma}_P = 0.184 \qquad \textit{log-lik}= 59.444$$

Model (1) confounds the effects of oil price changes with those due to fluctuations in the exchange rates. To solve this issue we should take into account that $O_t^{EUR} = O_t^{US\$} \times ER_t$, so the input variable in model (1) can be decomposed in the following way:

$$r^{12}(O_t^{EUR}) \simeq r^{12}(O_t^{US\$}) + r^{12}(ER_t) \tag{3}$$

and this decomposition suggests building a new model relating the inflation rate in the euro area, $r^{12}(P_t^{EA})$, with the annual growth of Brent prices in US\$ $r^{12}(O_t^{US\$})$ and the annual growth of the exchange rate, $r^{12}(ER_t)$. The main estimation results for this specification are the following:

$$\begin{aligned} r^{12}(P_t^{EA}) = (&\underset{(9\times10^{-4})}{0.0057} + \underset{(9\times10^{-4})}{0.0047}L)r^{12}(O_t^{US\$}) \\ &+ (\underset{(0.004)}{0.001} + \underset{(0.004)}{0.0023}L)r^{12}(ER_t) + \hat{N}_t \end{aligned} \tag{4}$$

$$(1 - \underset{(0.067)}{0.1362}L)\nabla\hat{N}_t = (1 - \underset{(0.056)}{0.4456}L^{12})\hat{a}_t \tag{5}$$

$$\hat{\sigma}_P = 0.182 \qquad \textit{log-lik}= 61.942$$

where the parameters associated to the exchange rate are non-significant. This result justifies the following final model:

$$r^{12}(P_t^{EA}) = (\underset{(9\times10^{-4})}{0.0056} + \underset{(9\times10^{-4})}{0.0046}L)r^{12}(O_t^{US\$}) + \hat{N}_t^P \tag{6}$$

$$(1 - \underset{(0.067)}{0.1357}L)\nabla\hat{N}_t^P = (1 - \underset{(0.055)}{0.4492}L^{12})\hat{a}_t^P \tag{7}$$

$$\hat{\sigma}_P = 0.183 \qquad \textit{log-lik}= 61.747$$

where the likelihood value is: (a) almost identical to the one achieved in model (4)-(5), so both models can be considered statistically equivalent and (b) larger than that of model (1)-(2), implying that the final model would be preferred to models (1)-(2) and (4)-(5) according to any Information Criterion.[10]

Model (6)-(7) has been submitted to a standard diagnostic testing process which includes:

1. computing the sample cross-correlation function of the model residuals against the prewhitened values of the input, see Figure 4, first panel, which shows no evidence of additional cross-correlation structure,
2. computing the sample cross-correlation function of the same residuals against the prewhitened values of the €/US$ exchange rate, see Figure 4, second panel, to assure that inflation in the E.A. does not display any significant reaction to changes in the exchange rate, and
3. overfitting experiments, in which we arbitrarily augmented the lag structure of model (6)-(7); the corresponding parameters were non-significant in all cases.

4 RESULTS

4.1 Assessing the likelihood of deflation

As the results in previous section show, changes in oil pricing have a significant effect on inflation. Accordingly, this variable is relevant to compute short-term inflation forecasts and, in general, to determine the monetary policy. As oil prices are highly volatile and, therefore, difficult to predict *stricto sensu*, it is reasonable to compute inflation forecasts conditional to a variety of oil price scenarios.

Accordingly, we will now compute the inflation paths corresponding to different scenarios for oil prices, using the model (6)-(7). To this end, first formulate the basic assumptions described in Table 4.

After setting these assumptions, we need to compute the most likely path for oil prices to reach the assumed annual variation rates. To this end, we created

[10]In all the transfer function models, we identified some outliers related with the sharp fall in oil prices started at the end of 2008. Although these outliers are statistically significant, the models reported here do not include the corresponding intervention terms because they do not affect significantly the results of the analysis.

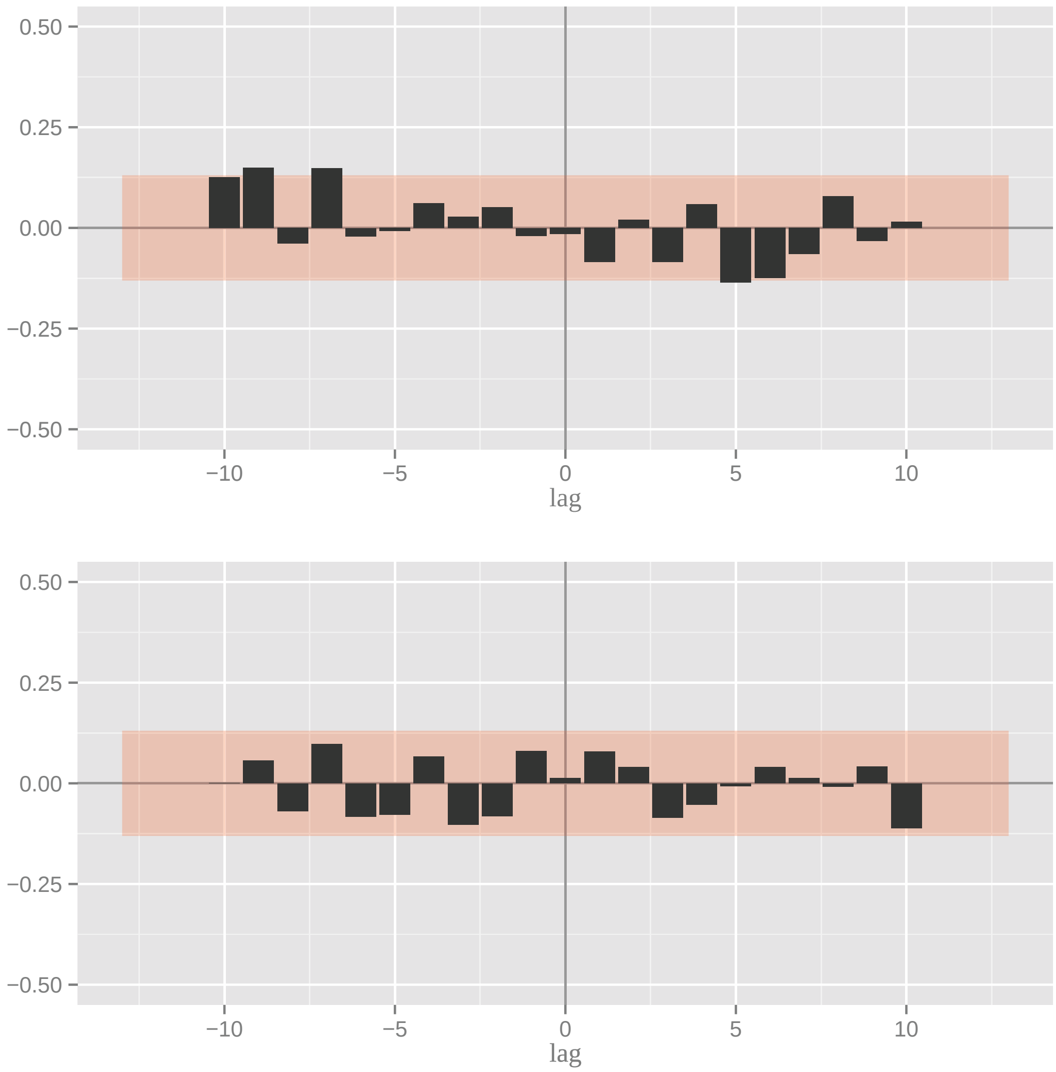


Figure 4: Cross correlations between: (a) the prewhitened annual variation rate of Brent prices and the lagged residuals of model (first panel), and (b) the same residuals and the prewhithened €/US$ exchange rate (second panel).

Table 4: Scenarios for Brent prices (US$/Barrel) in October 2016 versus October 2015. The assumption for pessimistic and extreme scenario consider that surplus of oil will persist in 2016 combined with a slowing demand expansion. See e.g., Currie et al. (2015)

Scenario	Assumed price	Annual variation rate
Stable	48.43	0%
Pessimistic	35.00	-28.0%
Extreme	20.00	-59.0%

.

three new variables by joining: (a) the past history of $r^{12}(O_t^{US\$})$ until October 2015, (b) eleven missing values corresponding to the months between November 2015 and September 2016, and (c) the value of $r^{12}(O_t^{US\$})$ corresponding to October 2016 according to each scenario. The missing values were then interpolated by processing this sample with a fixed-interval smoother, see Anderson & Moore (1979), assuming that the data generating process is the ARIMA model for $r^{12}(O_t^{US\$})$ (see Table 3). The output from this procedure can be interpreted as an univariate forecast for the annual change in Brent price, conditional to the corresponding end values[11]. This forecast is then feed to the transfer function in equations (6)-(7) to compute the corresponding inflation forecast.

The results of this exercise are summarized in Table 5. As it can be seen, none of the scenarios considered yields a negative inflation forecast.

These results suggest that the effect of oil prices on inflation is relevant but limited in the short term, as it is not enough by itself to create a long period of deflation. A deflationary spiral may occur however if an anemic inflation affects the agents' expectations and, through them, consumer decisions and economic activity. In this case, the short-term effect deflationary effects of oil prices would affect all the components of consumer prices.

4.2 Estimating the short-term effect of changes in oil prices

We will use the transfer function (6)-(7) to decompose the inflation rate history in two additive components, one driven by the model input (changes in the oil prices) and another one driven by the model errors, being the former an approximation for the short-term effect of changes in oil prices on inflation.

In this case, we can compute the part of annual inflation that can be attributed

[11]This procedure to compute the highest probability path for the exogenous input is a modest theoretical contribution of the paper.

Table 5: Annual inflation rates $r^{12}(P_t^{EA})$ corresponding to different scenarios for changes in brent prices $r^{12}(O_t^{US\$})$ in dollars.

	Stable		Pessimistic		Extreme	
Year-Month	$r^{12}(P_t^{EA})$	$r^{12}(O_t^{US\$})$	$r^{12}(P_t^{EA})$	$r^{12}(O_t^{US\$})$	$r^{12}(P_t^{EA})$	$r^{12}(O_t^{US\$})$
2015-10-01	0.12	-44.61	0.12	-44.61	0.12	-44.61
2015-11-01	0.2	-41.52	0.18	-43.52	0.17	-45.74
2015-12-01	0.42	-31.62	0.38	-35.98	0.35	-40.81
2016-01-01	0.69	-20.79	0.64	-27.3	0.58	-34.51
2016-02-01	0.59	-23.03	0.51	-31.95	0.42	-41.83
2016-03-01	0.58	-19.61	0.47	-31.07	0.36	-43.75
2016-04-01	0.57	-19.65	0.44	-33.57	0.29	-48.98
2016-05-01	0.46	-20.25	0.31	-36.63	0.13	-54.78
2016-06-01	0.53	-17.51	0.35	-36.42	0.15	-57.37
2016-07-01	0.57	-11.34	0.37	-32.69	0.14	-56.34
2016-08-01	0.68	-2.51	0.45	-26.07	0.19	-52.14
2016-09-01	0.83	-0.97	0.57	-26.86	0.29	-55.52
2016-10-01	0.78	0	0.5	-28	0.2	-59

to changes in Brent prices by propagating the following expression throughout the sample:

$$r^{12}(\hat{P}_t^{O}) = 0.0056\, r^{12}(O_t^{US\$}) + 0.0046\, r^{12}(O_{t-1}^{US\$}) \qquad t = 2, \ldots, n \qquad (8)$$

Note that Expression 8 results immediately from the transfer function of equation 6.[12] On the other hand, the part of annual inflation corresponding to any other factors is trivially computed as:

$$r^{12}(\hat{P}_t^{Other}) = r^{12}(P_t^{EA}) - r^{12}(\hat{P}_t^{O}) \qquad (9)$$

Figure 5 shows the profile of inflation in the E.A. versus the estimated effect of changes in Brent price, computed according to expression (8). It shows clearly that: (a) Brent prices have been a relevant factor to explain changes in consumer prices in the euro area[13] and (b) from 2013 onwards their effect has been either neutral or deflationary.

[12]Casals et al. (2010) derive a procedure to compute this decomposition for a general transfer function.

[13]During the period analyzed, this factor accounted for 25% of the variance of the stationary transform of inflation.

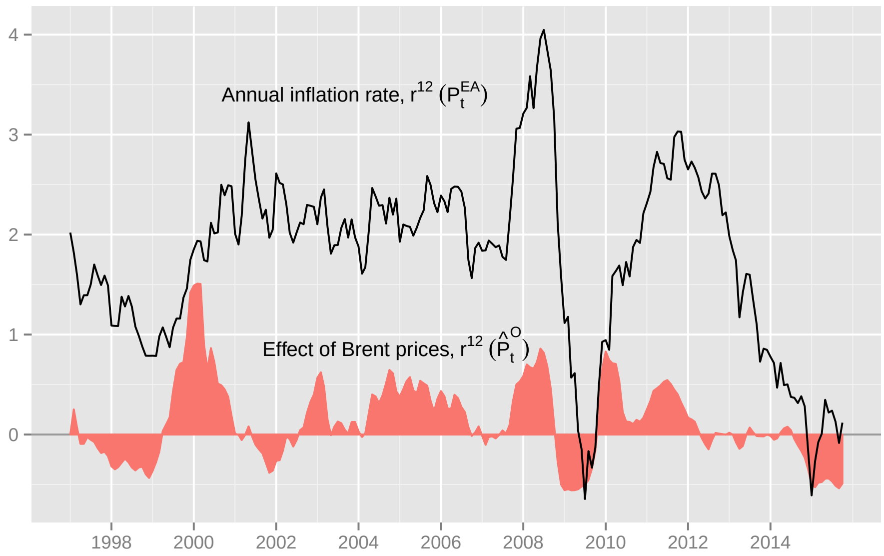


Figure 5: Annual inflation rates in the E.A. vs. the estimated effect of change in Brent prices.

Figure 6 provides further details on the effect of Brent prices from October 2015 to August 2016. It shows that they have been an important deflationary factor during this period, while the effect of other factors remained stable until November 2014, declined in December 2014 and January 2015, and started an inflationary cycle from February 2015 onwards.

4.3 A proposal to track inflation/deflation risks in real-time

The previous analysis suggests that, while oil prices are an important factor to explain recent deflationary pressures, a prolonged deflationary period would only occur if the negative evolution of crude factors creates a contagion on the other determinants of prices, e.g. through the agents expectations.

This idea suggests that the factor $r^{12}(\hat{P}_t^{Other})$ could be used to track in real-time the risks of deflation. In particular, as most analysts predict that oil prices will continue their decline, the future behavior of this component will determine if inflation will stay in positive values or fall into a negative spiral.

This method is flexible so that, if other risk factors are identified (e.g., weak economic growth), they could be added as additional inputs to the transfer functions and taken into account accordingly.

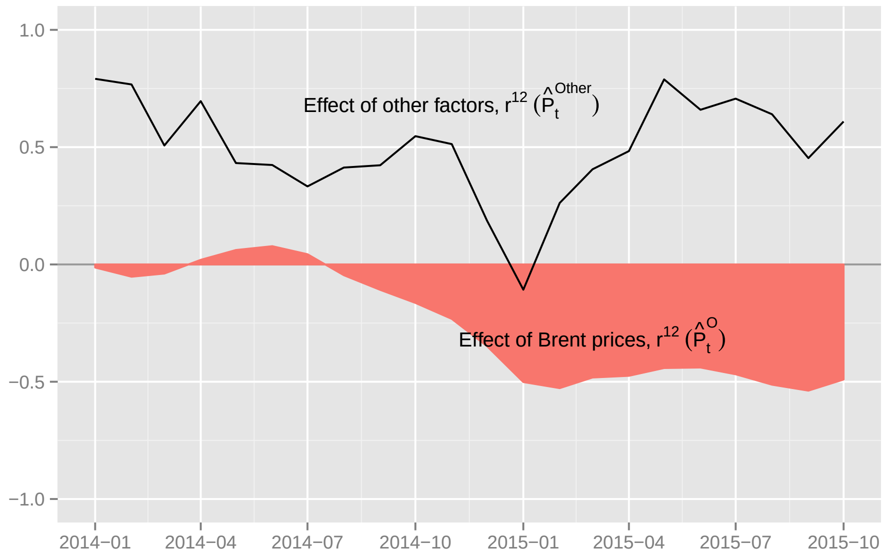


Figure 6: Components of inflation: effect of Brent prices vs. effects of other factors.

5 CONCLUSIONS

The effect of oil price changes on inflation rates has received renewed interest. Contrary to the shocks in the 1970s, nowadays it is the deflationary effect of oil prices which is under scrutiny.

In this work, we propose a method to evaluate the effect of oil price changes on inflation, as well as an indicator of inflation adjusted for the short-term effect of oil prices. Tracking such an indicator may be an effective way to assess the risk of deflation in real time.

We apply the methodology to compute twelve-months ahead forecast for inflation in the E.A., conditional to different scenarios of oil price deflation and to estimate which part of the recent evolution of consumer prices can be attributed to changes in oil prices.

Our main findings are: (a) negative inflation is not expected for the twelve-months-ahead forecasts in any of the three scenarios, (b) the short-time effect of oil on consumer prices is important, as it accounts for 25% of the variance of changes in inflation so, (c) a spiral of deflation/economic contraction could finally happen if a long period of anemic inflation/deflation affects the consumer expectations and, through them, the economic activity.

Future research will apply this framework to a disaggregate level of analysis. For example, the risk of deflation for specific countries may be evaluated. In addition, we will explore the effect of oil price variation on some specific components of the inflation rate.

Note that the methods proposed here could be applied to solve similar assessment and tracking needs in other frameworks, where a relevant economic magnitude, e.g., GDP, or unemployment, is affected by a driver variable such as a business climate indicator or some interest rates. In future papers we plan to explore some of these analyses.

All the calculations have been implemented in E^4, a free MATLAB toolbox for time series modeling, which can be downloaded at www.ucm.es/info/icae/e4. This website provides the source code for all the functions in the toolbox under the terms of the GNU General Public License, as well as a complete user manual and other reference materials. Besides E^4 we also used R and Gretl.

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Spanish and Portuguese electricity generation systems: an empirical approach with high frequency data

Tiago Lopes Afonso[1], António Cardoso Marques [1, 2], José Alberto Fuinhas [3]

[1] *University of Beira Interior, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, tiago.afonso@ubi.pt*
[2] *University of Beira Interior and NECE, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, amarques@ubi.pt*
[3] *University of Beira Interior and NECE, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, fuinhas@ubi.pt*

ABSTRACT

The Iberian market is organised in only two electricity generation systems, the Portuguese and the Spanish. The access to electricity markets is conditioned which brings several challenges to these systems. These characteristics make the analysis of the Iberian market even more exciting. The Iberian market was analysed in this paper, for the time span from July 2007 until October 2015. The study uses high frequency data given that the system management is accomplished on real time. VAR models for each country were estimated, using electricity generation sources. These models are highly robust to cope with the endogeneity detected through Granger causality tests. Both variance decomposition and the impulse response functions were carried out. The mix composition and the resources availability (renewable and non-renewable) are identical in both electricity generation systems, exclude the generation by nuclear plants. In this way the results are the expected. The results also show that the operation of the Spanish and Portuguese electricity generation systems is similar. This reinforces that the open access for the Iberian electricity market to another European electricity market can support a better utilization of the renewables already deployed, and to meet the electricity demand as well as to export the excess of the Iberian market. Demand response market programs are recommended, in way to benefit the accommodation of electricity generation sources.

KEYWORDS: Iberian market, VAR model, electricity price, generation sources, high frequency data.

1 INTRODUCTION

The electricity generation by renewable sources is already a reality in the domestic electricity mixes. An electricity power system should have internal mechanisms to accommodate this kind of sources, cross-border interconnections and pumping. The European Union has set renewable power generation targets and minimum targets of interconnections between countries. Cross-border interconnections are the most flexible instrument in the power system. The interconnections flexibility, i.e. the external market allows satisfy the electricity demand when the domestic generation is scarce, as well as to fix surplus when the electricity generation is high and demand is low. Another way to compensate the power system is the pumping. Pumping is used to export the surplus of electricity generated in off-peak periods. Different generation sources contribute to the generation mix, such as new renewable energies. The new renewables are characterized by: low marginal costs; high initial investment costs; and discontinuous generation. The external market is also important to meet electricity demand when the natural resources wind and sun are unavailable.

When the electricity market is restricted, such as the Iberian market, the markets of each country are strongly integrated. Once the interconnections between the Iberian electricity market (MIBEL) and the rest of Europe are scarce and conditioned, the two domestic electricity generation systems are very dependent on each other to meet the respective electricity demand.

The research question is: How do the Portuguese and Spanish electricity systems interact with the Iberian electricity market? The main goals are: (i) analyze the interaction between electricity generation sources within each electricity generation system; and (ii) analyze the impact of different generation sources in the electricity acquired in the Iberian electricity market. Considering the importance of diversifying the electricity mix, the electricity market can play an important role in the accommodation of different generation sources, without the necessity for investment in new generation infrastructures.

The time span for this study is from July 2007 (when Iberian market started operating) till October 2015. An electricity system is severely managed, so is expected endogeneity between variables. To handle with these characteristics the Vector Autoregressive (VAR) model is used.

The decision making of the electricity generation by nuclear plants is not captured by the database. The generation by nuclear plants has a base load role in the electricity system; therefore the generation by nuclear plants was used as an exogenous variable.

The results reveal that the both Spanish and Portuguese electricity generation systems operate similarly. Overall, the Iberian market is conditioned in the territory and it is urgent to add efficiency to the market in other to make easier accommodation of renewables market efficiency.

Demand response programs in electricity market are thus recommended, such as implementing price differentiation tariffs, so that the electricity generation demand follows the available generation.

2 LITERATURE REVIEW

Many countries have been implementing renewable energy sources (RES) in order to reduce carbon dioxide emissions (Helm, 2014; Kanellakis, Martinopoulos, & Zachariadis, 2013) and fossil fuels dependency. This transition from fossil to renewable sources results from the commitments with both national and international programs such as the Kyoto Protocol and the directives of the European Union, and most recently the *2015 United Nations Climate Change Conference*, in Paris.

The European Union Directives (European Commission, 2001, 2003, 2009) and incentive programs were established to deployment RES. The feed-in tariffs and minimum installed capacity of RES are some examples of incentives to RES, revealing the importance that the European Union has given to the new renewables (wind and photovoltaic). Feed-in tariffs are really effective in increasing the generation of electricity through renewable source (Proença & St. Aubyn, 2013). However the penetration of renewable sources through this type of incentive programs increases the electricity cost to final consumers (Gallego-Castillo & Victoria, 2015).

The intermittency problem of the renewable energy sources is well known (Cosseron, Gunturu, & Schlosser, 2013; Rahimi, Rabiee, Aghaei, Muttaqi, & Esmaeel Nezhad, 2013), this can lead to excess installed capacity (Flora, Marques, & Fuinhas, 2014).

It is far from clear the installed generation capacity of conventional sources has not too closely follow the installed capacity from RES backing them. Indeed, some literature is highlighting that larger use of RES could restrain the economic activity and the deployment of renewable energies requires economic prosperity (Marques, Fuinhas, & Afonso, 2015). The use of the new renewables requires a flexible system (Brouwer, Van Den Broek, Seebregts, & Faaij, 2014) A flexible system is characterized by high capacity generation by fossil fuels and renewable energies, high interconnections capacity and electricity storage.

The cross-border interconnections and the market integration issues have deserved particular attention in the literature (Puka & Szulecki, 2014; Richstein, Chappin, & de Vries, 2014). The interaction between electricity markets occurs through cross-border interconnections, in some cases with limited capacity as the Iberian Market.

Electricity mix and market integration are significant for spot price formation, particularly with large scale generation from sources with low marginal costs, essentiality wind power (de Menezes, Houllier, & Tamvakis, 2015). The European interconnection capacity target of 15% was defined, in order to promote the integration between European electricity markets, but this target might be insufficient to maintain electricity market integration (Figueiredo, Silva, & Cerqueira, 2015).

The two electricity generation systems discussed here are the Portuguese and the Spanish which have been described in the literature. A description of the Portuguese electricity generation system can be seen in Marques & Fuinhas (2015) and for the Spanish electricity generation system a description can be observed in Azofra, Jiménez, Martínez, Blanco, & Saenz-Díez (2015). The two electricity generation constituted the MIBEL further detailed description of the Iberian market can be observed in Domínguez & Bernat (2007) and Figueiredo et al. (2015).

3 DATA AND METHOD

In order to achieve the objectives defined previously, the variables used, for each country, are: (i) electricity generation by source; (ii) the market price for each country; and the (iii) total energy negotiated in the electricity market. The Spanish and Portuguese electricity systems were analyzed separately.

The management of the electricity system, in particular the composition of the mix, is realized on real time. As such, in order to assess accurately that dynamics, daily[1] frequency was used, for the period covering July 2007 (when Iberian market started operating) to October 2015 (according with the data availability in November 2, 2015). The analysis focuses on workweek (i.e. from Monday to Friday) (Santiago, Lopez-Rodriguez, Trillo-Montero, Torriti, & Moreno-Munoz, 2014), i.e. 2175 observations. According with the data from electricity generation by source in the Transmission System Operators (TSO) of each country, REN (Redes Energéticas Nacionais) and REE (Red Eléctrica de España), for Portugal and Spain, respectively. The sources of electricity generation considered are hydropower, fossil fuels, new renewable energy sources and nuclear plants (only for Spain); all this variables are in MWh. The hydropower (*HYDRO*) includes the electricity generated byrun of the river and stored water. The new renewable energy sources (*NEWR*) includes solar photovoltaic and wind power. The fossil fuels (*FOSSIL*) includes

[1] It is worthwhile to note that the smallest available frequency is 10 minutes to Spain and 15 minutes to Portugal. In order to obtain unbiased result, because of excessive white noise, the data were converted to daily frequency.

electricity generated by coal and natural gas. The nuclear plants (*NUCLEAR*) includes electricity generated only by nuclear power plants. The other variables are extracted directly from the database of the electricity market operator (OMIE) of the MIBEL, in the section Market Results. The Portuguese arithmetical average price (*PMPT*) and Spanish arithmetical average price (*PMS*) are the daily marginal price (EUR/MWh) of each electricity generation system. The total energy acquired in the Iberian Market (*EIM*) is the sum of the electricity purchased by the two electricity generation systems.

Electricity generated by fossil fuels can play a double role in the management of the system, namely backing-up renewables (mainly natural gas turbines) and base load role (mainly coal). Hydropower allows the storage of water in order to generate electricity, also have a back-up and base load role, unlike the *FOSSIL,* does not contribute to the greenhouse gas emission. The energy negotiated in Iberian market depends on the capacity of interconnections, the market price and electricity demand on real time in each electricity generation system. When the market price is low, one of the systems can import electricity excess from the other electricity system, preventing the network congestion. Nuclear plants are the less flexible energy source, i.e. the inability to quickly increase the electricity generated. Due to the inflexibility in the generation, has a base load role within the electricity system, is always in continuous generation and has dispatch order.

3.1 Unit root tests

To check the stationary properties of the series, traditional unit root tests were performed, namely ADF (Augmented Dickey Fuller) test and PP (Philips Perron) test. Results can be seen in table 1. The null hypothesis for the ADF test and PP test is the series has a unit root, thus the variable is non stationary. The tests results reveal great consistency. The null hypothesis is rejected, supporting the stataionarity of the variables in levels, in both tests. The series are integrated of order 0 (stationary).

Table 1. Unit root tests

	ADF		PP	
Variables	CT	C	CT	C
Spain				
FOSSIL	-4.616713***	-3.333643**	-21.70084***	-14.41043***
HYDRO	-4.183631***	-4.101026***	-21.77250***	-21.19450***
EIM	-7.285092***	-6.546155***	-10.70109***	-8.966770***
PMS	-3.874714**	-3.872162***	-13.37160***	-13.37288***
NEWR	-5.882330***	-4.189259***	-25.55988***	-25.64548***
NUCLEAR	-6.814762***	-6.820908***	-7.055664***	-7.060036***
Portugal				
FOSSIL	-7.123076***	-4.731924***	-14.32731***	-11.62260***
HYDRO	-4.058069***	-4.013395***	-6.053477***	-5.913246***
EIM	-7.285092***	-6.546155***	-10.70109***	-8.966770***
PMPT	-3.620258**	-3.547552***	-10.52695***	-10.15500***
NEWR	-7.901172***	-5.343984***	-28.52213***	-28.86307***

Notes: C stands for constant; CT stands for constant and trend; *** and ** represents significance level of 1% and 5%, respectively.

3.2 VAR model

Once verified that the variables are I(0), the VAR (Vector Autoregressive) model was estimated with the variables in levels. It is expected that the adjustment speed of the variables within the electricity system is fast. VAR model is well known in the energy science, it is used when the variables are simultaneously explained and explanatory. This model can be specified:

$$X_t = \sum_{i=1}^{k} \Gamma_i X_{t-i} + CD_t + \varepsilon_t \,, \tag{1}$$

where k is the number of lags Γ_i and C are the coefficient matrices of endogenous variables; ε_t denotes the residuals, X_t = [endogenous variables] and D_t = [constant and other exogenous variables].

The first step in the research procedure is analyzing the optimal lag length. After this, the Granger causality/Block Exogeneity Wald test was performed, in order to examine the endogeneity of the used variables. In the third step residual diagnostics tests were computed. The variance decomposition and impulse responses function analysis were performed. The forecast error variance decomposition allows observing how a variable responds to shock in specific variables. While the impulse response functions allows observing the behavior of the variables, into account the existence of an impulse in one variable.

4 RESULTS

The results show how the generation sources interact one each other and with the market energy. The results of the lag order selection for the Spanish and Portuguese electricity systems can be observed in table 2.

Table 2 – Information criteria for optimal lag length choose

Spain				Portugal			
Lag	AIC	SC	HQ	Lag	AIC	SC	HQ
6	119.9369	120.5238*	120.1517*	3	91.72357	91.93507*	91.80095
16	119.7880*	121.3266	120.3509	5	91.66372	92.00741	91.78947*
				6	91.64262*	92.05241	91.79255

Note: * indicates the optimal lag order selected by the criterion

To Spain Schwartz information criterion (SC) and the Hannan-Quinn information criterion (HQ) obtained the same result, so 6 lags. The Akaike information criterion (AIC) appoints to 16 lags. Once the data are daily, considering the workweek (Monday-Friday), i.e. 5 days per week, Schwartz information criterion was chosen. In the case of Portugal, the same information criterion was chosen, so that the analysis remains consistent. Whichever criteria the results for the diagnostics tests remain unchanged, to the model of Portuguese electricity system. As such, the optimal lag length was chosen, 6 and 3, to Spanish and Portugal, respectively. Taking into account this lag selection the Granger causality was performed and the results can be seen in fig.1 and fig. 2.

The results of fig. 1, strongly suggest that the variable *NUCLEAR* should be considered as exogenous variable. Nuclear is only caused by *NEWR*, and it causes *HYDRO* and *EIM*. Regarding the other variables, these must be considered as endogenous variables, which reinforce the appropriateness of use of VAR modeling to understand the relationships between generation sources and electricity market.
Attending to the Portuguese case, the fig. 2 reveals the result of the Granger causality test.
Considering the high endogeneity between electricity generation and the Iberian Market, the results of the Fig. 2 were expected. In short the causalities founded are: FOSSIL↔HYDRO; FOSSIL↔EIM; FOSSIL→PMPT; NEWR→FOSSIL; EIM↔HYDRO; PMPT↔HYDRO; NEWR↔EIM and EIM↔PMPT.

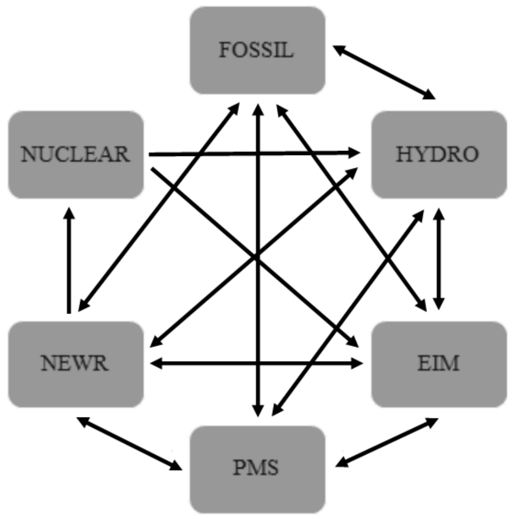

Figure 1. Granger causality test/Block Exogeneity Wald Tests – Spanish electricity system

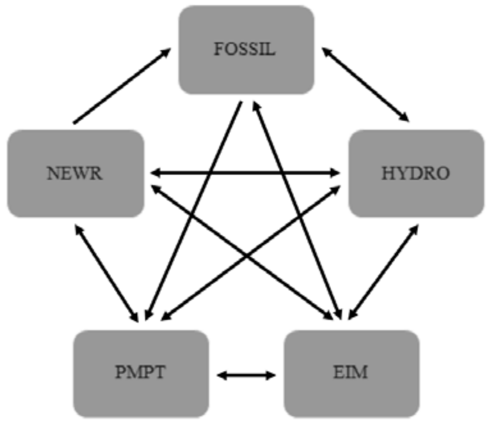

Figure 2. Granger causality test/Block Exogeneity Wald Tests – Portuguese electricity system

Residual diagnostic tests was made by both models. The autocorrelation LM has the null hypothesis: no serial correlation. The null hypothesis for White test (no cross terms) is: homoscedasticity. To Jarque-Bera normality test the null hypothesis is: error terms follows a normal distribution. For all tests the null is rejected at significant level of 1%. The residual diagnostic results is in line with de Menezes & Houllier (2015). In high frequency data (daily) this result is not a problem (Lumley, Diehr, Emerson, & Chen, 2002), the series are not follows a normal distribution due the high value of kurtosis, i.e. the distribution is leptokurtic.
The variance decomposition for Spanish electricity system is presented in table 3.

Table 3 - Variance decomposition – Spanish case

Variance Decomposition of HYDRO:						
Period	S.E.	HYDRO	FOSSIL	EIM	PMS	NEWR
1	16081.97	100	0	0	0	0
5	18210.14	91.28187	4.296249	0.657051	3.449975	0.314855
7	20529.71	82.48776	7.061019	0.852925	3.438917	6.159379
30	30247.75	47.12221	27.58736	4.255255	6.169336	14.86585
Variance Decomposition of FOSSIL:						
Period	S.E.	HYDRO	FOSSIL	EIM	PMS	NEWR
1	45020.72	22.39362	77.60638	0	0	0
5	65385.91	14.49928	82.73235	0.337833	2.133723	0.296816

7	75235.29	12.12013	82.69564	0.547501	1.652668	2.984069
30	97337.72	7.851452	85.08326	1.991007	1.143684	3.930593

Variance Decomposition of EIM:

Period	S.E.	HYDRO	FOSSIL	EIM	PMS	NEWR
1	30829.64	0.507853	0.018282	99.47387	0	0
5	47463.24	0.694283	0.623018	97.84883	0.250886	0.582983
7	52820.25	0.832335	1.89376	95.14724	0.289355	1.837306
30	73712.55	1.916856	14.00376	75.11919	0.176203	8.783987

Variance Decomposition of PMS:

Period	S.E.	HYDRO	FOSSIL	EIM	PMS	NEWR
1	6.011174	3.18087	1.812466	2.066986	92.93968	0
5	8.426566	2.645976	4.374908	1.190066	90.73265	1.0564
7	9.222297	2.257924	5.577382	1.08812	89.91487	1.161705
30	12.31884	2.244359	10.1562	0.673849	85.95821	0.967383

Variance Decomposition of NEWR:

Period	S.E.	HYDRO	FOSSIL	EIM	PMS	NEWR
1	49008.63	32.62892	24.63367	0.625712	0.803205	41.30849
5	62955.81	24.9827	29.10571	1.814617	4.314247	39.78273
7	64384.07	24.25275	29.67517	1.83802	4.127793	40.10627
30	68227.09	21.84215	33.53053	1.65352	4.344499	38.6293

Note: Cholesky Ordering: HYDRO FOSSIL EIM PMS NEWR

After one month, shocks in *FOSSIL* explain around 28% of the forecast error variance of the *HYDRO* and *NEWR* explain about 15 %. But most is explained by *HYDRO*. *HYDRO* has a back up role in the system, it is more flexible, as well as gas turbines are. The intermittêncy is not a problem since there is no shortage of water in reservoirs. This result is consistent with the choice of the variabless as endogenous. About *FOSSIL*, the forecast of the error variance is explained in large part by *FOSSIL (85%).*Coal plants are included in *FOSSIL*, it is a kind of source with low flexibility, so it is used in the base load

In the case of *EIM* is explained by itself, but *NEWR* explaind around 9% and *FOSSIL* 14 %. When the resource wind is available and coal generation is high, but with low costs, the spanish system export the electricity excess, and in the other hand when the generation by wind and solar is to low, the system imports electricity. The forecast of the error variance of the *PMS*, after 30 periods, is explained bay *PMS*, and only 10% by *FOSSIL*, but the reverse is not true. The cost of fossil fuels depends of the fossil raw materials price and not the electricity price market.

The *NEWR* has a dispach order in the system, but is depend of the availabily of the natural resources, wind and sun. The renewable back-up is a necessity, so the back-up is made by *HYDRO* and *FOSSIL,* after only 1 period*,* explain around 33% and 24% of the forecast error variance. The *EIM* not have much influence in the generation by renewable sources, because this kinde of source is predictable but not controlable.

The nuclear plants is the less flexible generation source and also has a dispach priority, the generation is continuous, therefore the producion is independent of the other sources, but the other sources must into acount the generation through nuclear plants.This is why the *NUCLEAR* is used as exogenous variable. The decision to the use of nuclear plant is not capturated by the data base used in this study.

The fig 3 represents the Impulse Responses Functions to the endogenous varibles, in the spanish system. In general, all variable converge to the equilibrium in one month, therefore, there is no presence of long memory, the adjustment is fast.

HYDRO and *FOSSIL* does not respond to the shocks in the *EIM*, only *NEWR* has a smal negative response. The back-up from *FOSSIL* and *HYDRO* to *NEWR* must be done on real time. The response of *HYDRO* and *FOSSIL* to a shocks in the *NEWR* is not constant, depends the availabiy of the resources. The new renewables has a negative response in shocks in the *HYDRO* and *FOSSIL*, but meet quickly to the equilibrium. A one standard deviation shock to the *PMS* increases *HYDRO* and *FOSSIL* but not *NEWR*.

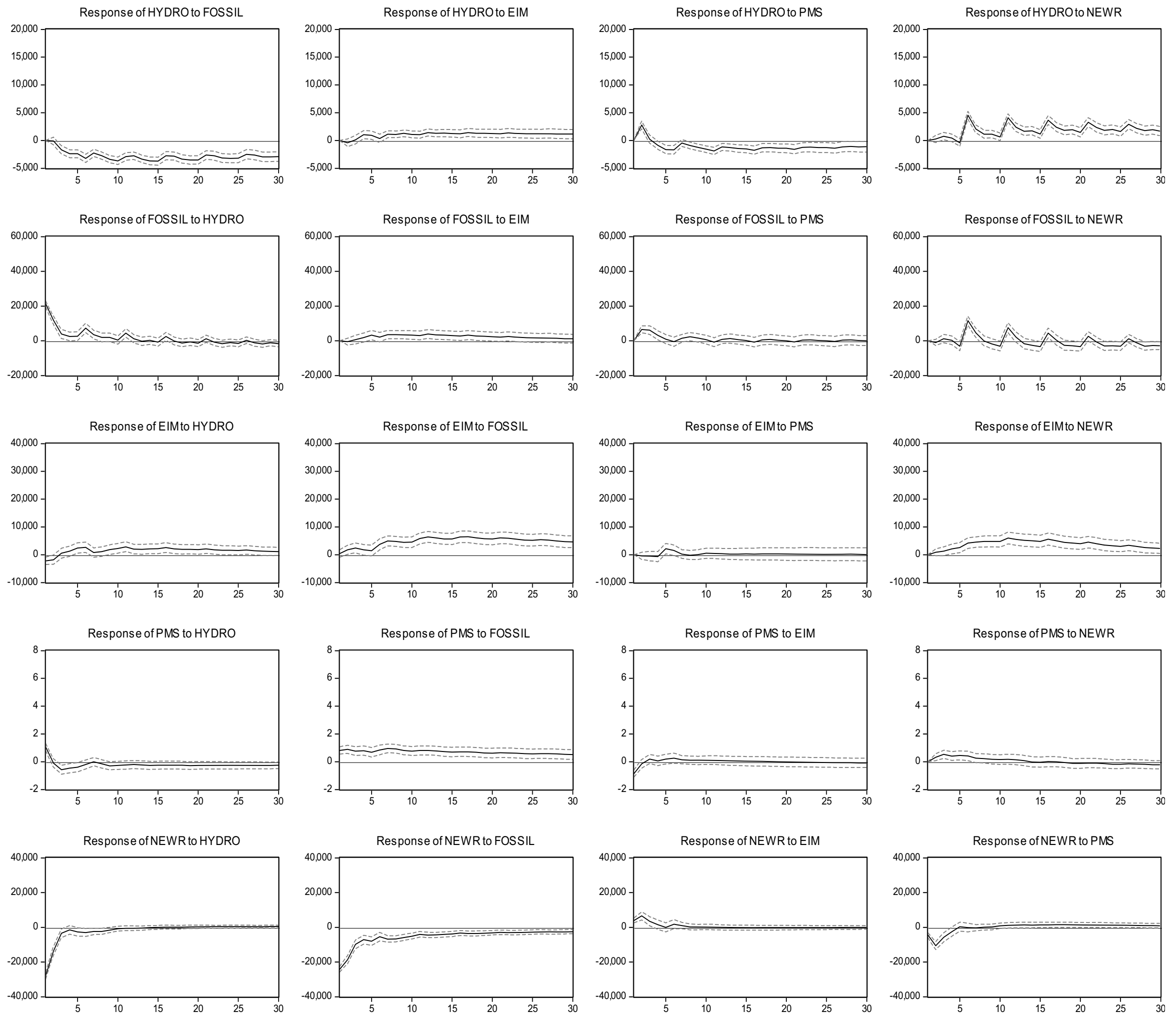

Figure 3. Impulse responses functions – Spanish case

In the estimated model for Portuguese electricity system, there are no exogenous variables. The forecast error variance was presented in table 4. After one period, the forecast error variance from *HYDRO* is explained by itself in 100%. But after 5 days this explanation is divided, around 14% and 77% to *FOSSIL* and *HYDRO*, respectively. Only after 30 periods *NEWR* explains 14% of the forecast error variance of the *HYDRO*. The substitution effect between *HYDRO* and *FOSSIL* is only noticeable after 30 periods.

About forecast error variance to *FOSSIL*, after 30 periods, FOSSIL is explained by itself in 90%. Electricity generation by coal has a base load role in the Portuguese system, and the production in this type of source is uninterruptible. *EIM* explains around 94% forecast error variance of the *EIM*, comparing this with the Spanish models, the Spanish electricity system has a big impact in the Iberian market, due the dimensions of this system, compared to Portuguese system. Forecast error variance of *PMPT* is explained, after 30 periods, by FOSSIL in 29%. Usually the price market taking into account the generation of the fossil sources and not the renewable sources, it is implied in that result. About *NEWR*, the forecast error variance is explained, after only one period, by *FOSSIL*, *HYDRO* and *NEWR* in around 29%, 17% and 50%, respectively. The back-up from *FOSSIL* and *HYDRO* is well represented here.

Table 4 - Variance decomposition – Portuguese case

Variance Decomposition of HYDRO:						
Period	S.E.	FOSSIL	HYDRO	EIM	PMPT	NEWR
1	9019.372	0	100	0	0	0
5	13494.97	13.91867	77.34857	1.759597	1.400403	5.572761
7	14447.54	19.79616	67.46653	2.498602	2.021829	8.216881
30	18273.32	37.29182	39.53447	4.700759	3.98833	14.48462
Variance Decomposition of FOSSIL:						
Period	S.E.	FOSSIL	HYDRO	EIM	PMPT	NEWR
1	5707.21	91.4322	8.5678	0	0	0
5	8816.789	92.52499	5.98834	1.20137	0.102728	0.182576
7	10018.67	93.00219	5.233751	1.441262	0.153209	0.169584
30	16887.14	90.35445	5.903055	1.395856	0.185549	2.161094
Variance Decomposition of EIM:						
Period	S.E.	FOSSIL	HYDRO	EIM	PMPT	NEWR
1	31689.49	1.492922	0.000198	98.50688	0	0
5	52698.22	2.164474	0.331366	97.21657	0.044509	0.243083
7	58066.95	2.923975	0.601308	96.17606	0.086155	0.212503
30	76233.86	6.718898	1.969982	89.95164	1.022833	0.336648
Variance Decomposition of PMPT:						
Period	S.E.	FOSSIL	HYDRO	EIM	PMPT	NEWR
1	5.753961	28.66577	9.55822	3.323762	58.45224	0
5	8.731599	32.46873	6.505809	1.611126	58.8496	0.564727
7	9.47965	31.76084	5.537363	1.385602	60.83702	0.47917
30	12.88961	29.39156	3.705995	0.942244	65.07342	0.886777
Variance Decomposition of NEWR:						
Period	S.E.	FOSSIL	HYDRO	EIM	PMPT	NEWR
1	13769.32	28.6744	17.18767	2.860981	1.396657	49.8803
5	16895.05	29.84892	13.75749	2.396783	1.376567	52.62025
7	17091.34	29.90213	13.53972	2.374458	1.347775	52.83592
30	17650.97	30.86321	13.93478	2.354213	1.313222	51.53458

Note: Cholesky Ordering: HYDRO FOSSIL EIM PMPT NEWR

In fig 4, the impulse response to the endogenous variables, in the VAR model of the Portuguese system. All variables converge to the equilibrium, in 30 periods, but with different adjustment speed.

A one standard deviation shock to *FOSSIL* causes a negative response by *HYDRO*. NEWR has different responses when a deviation shock is introduced in other variable. *FOSSIL* and *HYDRO* decreases *NEWR* due the necessity of back-up, by the other hand *EIM* increases, but with a small impact on *NEWR*. The electricity exports are made when the electricity generation by renewable sources is in excess. The impulse response of the *HYDRO* to *NEWR* shows that one standard deviation shock to *NEWR* tends to rises *HYDRO*. This result is consistent with the literature (Marques & Fuinhas, 2015) and with the results obtained in the forecast error variance, there is a substitution effect between *HYDRO* and *NEWR*, *NEWR* has dispatch order, but intermittent generations, while *HYDRO* is always available.

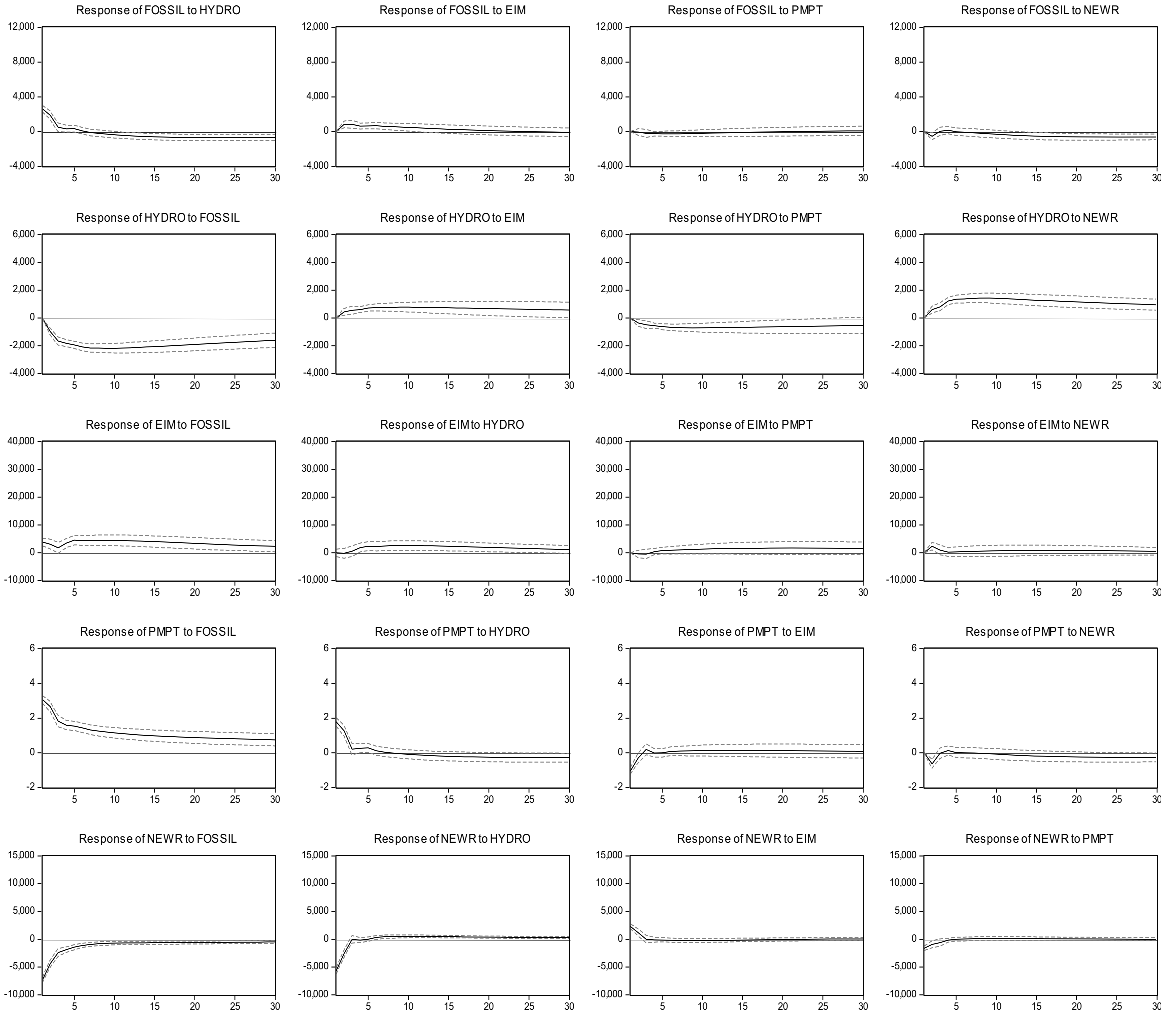

Figure 4. Impulse responses functions – Portuguese case

5 DISCUSSION

This paper is focused on the analysis of the interactions between electricity generation sources, within two separate domestic electricity sources which must be cooperating between them. Both the Spanish and the Portuguese electricity systems are analyzed and confronted. The system is managed on real time, so high frequency data, is used to ensure the quality estimates and to capture the real time management. The 5 weekdays (Monday to Friday) was chosen by two reasons. The first reason was the needed to separate the different ways to manage the power system, in the weekend, is when most people consume electricity in their homes, and throughout the week is when the industries operate. The composition of the electricity mix and management of the power system is different in these periods, because off the need to meet the electricity demand. The second reason was the need to reduce the white noise of the series, the reduction procedure weekdays from 7 to 5, allows examining the entire period, capturing the economic cycles. Two VAR models were estimated, one for each electricity system of the Iberian Market. This model is highly robust in the presence of endogeneity among variables. After this the variance decomposition and the impulse response functions were performed.

The market variables *PMS*, *PMPT* and *EIM* were used to understand the progress of the Iberian market. The *EIM* variable, i.e. total electricity negotiated within the Iberian Market, is used both estimated VAR models. The results show that in the Spanish electricity generation system a change in *EIM* results in an impact on *FOSSIL* and *NEWR*. In the other hand in Portuguese system *FOSSIL* and *HYDRO* also suffer an impact when there is a shock in *EIM*, but with less intensity than Spanish system. It is necessary into account that cross-border interconnections between Portugal and Span are limited.

The price market for both electricity systems were overlapping most of the time. This means that capacity in the interconnections was available at most of the time and only when the interconnections were fully occupied the price was different. The decision to import or export electricity, by the Spanish or the Portuguese electricity system, depends on the market price, but mostly on the cost to generate electricity.

Regarding the results of the interaction between electricity generation sources within each system, the results are similar in both, excluding the electricity generation by nuclear plants. These results provide further evidence that the management of both electricity generation systems should be made in an integrated mode. When two distinct systems have different characteristics the adjustment or compensation is more advantageous. The interaction with other European markets can be useful to export electricity and meet the demand when renewable are not available. With electricity market it is possible meet the demand without the increase of the installed capacity. Spanish and Portuguese policy makers already suggest this option, but this option cannot be the first best. Given the high penetration level of renewable energy sources, both in electricity systems and in the non-influence by *NEWR* has in the market price.

The electricity markets that are restricted in the territory, like the Iberian market, should set up demand response market programs. The deployment of these programs can help make the market more efficient. The low marginal costs of the renewable energies must be included in the electricity market price.

6 CONCLUSION

The diversification of generation sources requires flexibility due to the different characteristics of each type: intermittent generation; high generation costs; and incapacity to quickly increase the generation. The management of the surpluses and the scarcity are also regarded in the flexibility required to mix diversification. Thus, the flows of exports and electricity imports can be essential in this task of diversifying electricity generation sources.

The interaction between electricity generation sources within the Portuguese and Spanish electricity generation systems were studied separately, for the time span from July 2007 until October 2015. High frequency data was used. Iberian market does not have access to another electricity market.

The results confirm the requirement for electricity exchange between the Iberian electricity generations system with the rest of Europe. Both electricity generation systems are similar on the mix composition and operate similarly. This way of operating can be explained by the availability of resources (renewable and non-renewable) and the geographical proximity. The implementation of demand response market programs in order to make the operations of each electricity system most favored to accommodate different kinds of generation sources.

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Uncertainties in the estimate of wind energy production

LIRA, A. G.[1]; ROSAS, P.A.C [2]; ARAÚJO, A. M[3]; CASTRO, N. J.[4]

[1] *Federal University of Rio de Janeiro – UFRJ; Economy Institute- IE; Study Group of Electric Sector – GESEL; 250 Pasteur Avenue, Rio de Janeiro, Brazil;* adrianogouveia04@gmail.com

[2] *Federal University of Pernambuco – UFPE; Department of Electrical Power System Engineering; Academico Helio Ramos Street– Cidade Universitária, Recife, Brazil;* pedro.a.rosas@gmail.com

[3] *Federal University of Pernambuco – UFPE; Department of Mechanical Engineering; Arquitetura Avenue – Cidade Universitária; Recife; Brazil* ama@ufpe.br

[4] *Federal University of Rio de Janeiro – UFRJ; Economy Institute- IE; Study Group of Electric Sector – GESEL; 250 Pasteur Avenue, Rio de Janeiro, Brazil;* nivalde.castro@gmail.com

ABSTRACT

The Annual Energy Production (AEP) estimated over the lifecycle of the project is one of the most important factors to determine the profitability of wind power project. The methods used to estimate the AEP in a wind farm requires an assessment of the uncertainties associated at all steps. To finance a wind power project, banks requires that the developer submit the uncertainties related to the estimation of AEP's wind farm, to mitigate errors and increase the project reliability. The appropriate assessment of uncertainties is critical to determine the feasibility and risk in developing a wind energy project. This study presents the main sources of uncertainty in the energy estimate process in wind farms. This information is important for the correct analysis of the economic viability of the project.

KEYWORDS: Wind Power, Uncertainty, Annual Energy Production

1 INTRODUCTION

The energy production in a wind farm follows a stochastic principle and, as such, requires a statistical analysis in which production estimates should be associated with occurrences probabilities.

An uncertainty analysis is often performed as part of a wind farm energy yield assessment. The economic viability of a wind farm requires an analysis of the risks associated with the production uncertainties.

The Section 3 this paper describes the main sources of the uncertainties in an energy assessment. Each wind farm development uncertainties must be individually determined and then calculated for the entire project. The are several methods, such as the IEC method (IEC 61400-12 Power Performance Testing) for the evaluation of measurement uncertainty or the Monte Carlo method, which lead to different results related to the different processes.
An interesting way to present the project uncertainties is by giving the probabilities of exceedance in terms of expected annual production of the wind farm.
In the financing process of wind farms, banks have specific requirements in order to ensure that the energy estimate has the smallest error margin possible. In Brazil, due to of auctions, the Energy Research Company - EPE, demands a declaration issued by an independent certifying, declaring the Physical Guarantee (GF), which is the annual energy availability for each wind farm competing in the energy auction.
In order to mitigate the risk that energy production be less than the one on contract, the Physical Guarantee of the wind power generated must be calculated taking into account all sources of uncertainties in the project, so that the certified energy can bear a 90% probability, being attained or exceeded. This value is called P90.
According to Tolmasquim et.al. (2013) the economic viability of wind energy production within the regulatory framework of the Brazilian electricity market emerged for the need for a set of specific rules, aimed at the following objectives:

• To imbue the business agent with the effective production of the energy contracted;
• To minimize cost of energy, reducing the financial cost of projects, mitigating uncertainty in revenues from energy sales;
• Encourage the efficient procurement of the wind farm; and
• Reduce the risk of non-compliance of the contracted energy amount.

With the current energy auctions rules, entrepreneurs are penalized for producing below the contracted amount of energy, pursuant to a tolerance margin.
Reducing uncertainty by increasing the quality of the criteria design is the only way to keep the financial risk of a wind farm within acceptable limits for financiers, besides providing greater security in meeting energy demand.
It is important to understand the main sources of uncertainties in a wind farm project in order to reduce their magnitude and then accurately calculate its impact on yield forecasts.

2 LITERATURE REVIEW

There are many references to research about uncertainties in the estimation of the wind farm energy production.
To name a few, in Lira (2012) is presents the main sources of the uncertainty in wind energy production, in Pedersen et.al. (2006) is presents an analysis of the performance of some types of anemometric, in Mortensen et.al. (2006), Corbett (2012) and Mortensen et.al. (1997) are presents the uncertainty about the wind flow simulation models and in Lackner, M. A. (2008) is present new approach for wind energy site assessment considering uncertainty.

3 OBJECTIVE

The calculation of the estimative energy production from a wind farm is subject to uncertainties that must be accounted for in order to assess the risk of investments based on the accuracy of the estimated energy production.
The main goal of this paper is to present the main sources of uncertainty in energy production estimate process for wind farms in order to identify the expected improvement in energy reliability and reduce the financial risks of the projects.

3 MAIN SOURCES OF UNCERTAINTIES

The main sources of uncertainties can be split into two groups: Wind Resource Uncertainty and Energy Production Uncertainty.

3.1 - Wind Resource Uncertainty

This uncertainty has to do with limitations in the measurement process at meteorological tower. Included the uncertainties associated with the type of the sensor, installation and calibration of sensors, location of the towers, etc.

To turn the uncertainty of the wind resource into uncertainty in energy production the sensitivity factor is required. The sensitivity factor corresponds to the variation in energy production caused by wind variation, it is specific value for each project. Energy production and wind speed shows no linear relationship.

3.1.1 - Sensor accuracy

The quality of results is directly dependent on the quality of equipment and the way they are installed at the meteorological tower. The costs of a high-quality measuring system and its appropriate installation are small when compared with the costs of a wind farm. It is recommended the use of the anemometers models *This First Class* or *Vector*, which despite their higher prices, they have reduced measurement uncertainties when other sensors on the market are taken into account. The Fig. 1 shows the main models of the cup anemometers.

NRG Maximum 40 (NRG)	Risø P2546 (RIS)	Thies First Class (THF)	Vaisala WAA151 (VAI)	Vector L100K (VEC)

Fig. 1- Main models of the cup anemometers. *Source*: Pedersen et.al. (2006)

According to IEC 61400-12-1 (2005) the Eq.1 gives the operational standard uncertainty

$$u_i = (0{,}05\,m/s\ + 0{,}005 * U_i) * \frac{k}{\sqrt{3}} \qquad \text{Eq.1}$$

Where: $U_i$is wind speed bin and k is classification number

According to Pedersen et.al. (2006) the simple uncertainty range in terms of wind speed and associated with the instrument's accuracy for an isolated sensor comprises values between approximately 1% and 6%.

3.1.2 - Sensor calibration

One important aspect concerning quality warranty of wind measurement is the anemometers calibration through an appropriate wind tunnel. There are studies that show uncertainties greater than 3.5% from anemometers calibrated in various wind tunnels. For this reason, MEASNET – *Measuring Network of Wind Energy Institutes* – has issued a measurement method for measuring cup anemometers calibration, especially custom-made for wind energy.
By following this practice, institutions provide guarantee that the wind tunnels used will not differ more than 0,5% in the reference wind speeds and, thus, such a procedure will provide a small and controlled uncertainty from the anemometers certified by the aforementioned method.
Currently, the great majority of research and wind power assessment institutions require that anemometers have calibration certificates issued by institutions that have the MEASNET stamp, that is, they observe the calibration standard set by that institution.
The use of individually calibrated anemometers poses a direct impact in reducing the wind speed measurement uncertainty.
According to Coquilla et.al. (2008) the mean relative uncertainty on the calibration of various cup and propeller anemometer models is present in the Table 1.

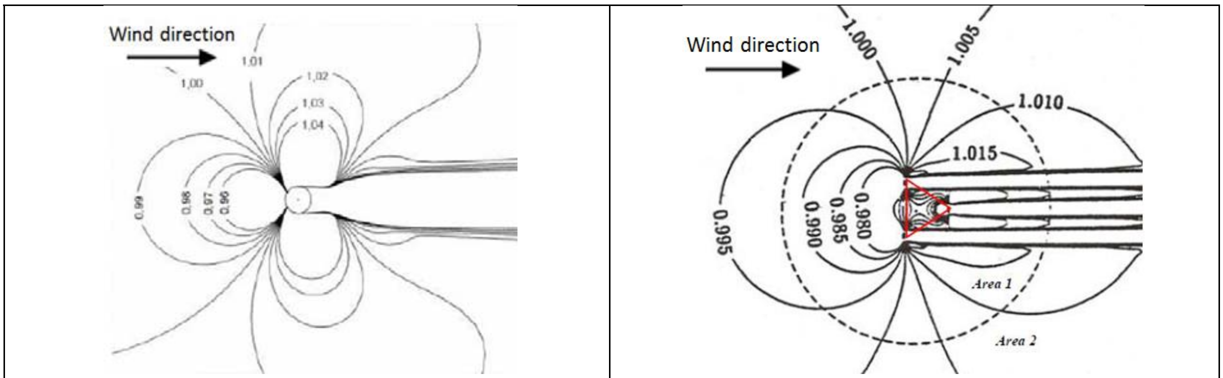
Table 1 - Mean relative uncertainty.

Cup Anemometer Model	Mean Relative Uncertainty (%)
NRG #40	1,48
NRG IF3	1,66
Risoe Cup	1,43
R.M. Young Propeller	0,50
R.M. Young Wind Monitor	0,75
R.M. Young Wind Sentry	1,02
Second Wind C3	1,64
Thies First Class	2,04
Vaisala WAA252	1,98
Vector A100LK	2,06
Vestas Cup	1,09

Source: Coquilla et.al. (2008)

3.1.3 - The uncertainty due to assembly of the sensor

The anemometers and direction sensors (wind vane) should be fixed in the tower by means of rigid booms, so there is no vibration in the sensors and thus the data measurement will suffer no interference. The length of the boom-mounted must follow pursuant to IEA's recommendations - International Energy Association. The separation between the tower and the sensors should reflect the level of uncertainty considered acceptable.
Fig. 2 shows iso-speed plot with flow disturbance because of the proximity to the tower. On the left is a tubular tower and to the right a triangular lattice tower.



Tubular Tower | Triangular Lattice Tower

Fig. 2 – Meteorological tower interference in the wind flow. *Source:* IEA (1999)

In order to minimize tower interference in the anemometer, this equipment must be apart from the met tower by a minimum distance, and positioned where the wind speed isolines interference reaches the closest value to the unit, making use of the prevailing direction of wind as reference.
The IEA´s standard guidelines recommends for tubular towers and a 0,5% error, the minimum distance between the sensors and the tower be 8,5 times the diameter of the tower, measured from the center of the tower. For lattice towers and a 0,5% error, the distance should be at least 5,7 times the width of the face. It is recommended, however, that the boom-mounted should not be much bigger than this measure to reduce vibrations.

3.1.4 - Uncertainty in the long-term wind prediction

The wind displays a stochastic behavior where a significant interannual variability is observed, that is, wind speed average may vary from year to year.
Wind measurements in short periods (1-3 years) are not indicative of long-term wind resource due to interannual variability.
Therefore, to assesses correctly a local wind potential a long period of data is required to reduce the error associated with these wind behavior changes over the years. Thus, to reduce errors in the estimate of the wind farm energy production, a data correction measured on site with long-term data is carried out. This correction improves the estimate of long-term wind speed, but also brings uncertainty in the process.
To analyze the uncertainty in the long-term wind prediction is important take into account the uncertainty on historical wind conditions and the uncertainty in future wind variability.
The uncertainty in the historical wind conditions is related with the correlation between the target site (measured data) and the reference station (long-term data). The weaker the correlation with

the reference station, the larger the uncertainty in the adjusted long-term wind resource at the target site, some estimates are given in the Table 2.

Table 2 - Wind Speed correlation uncertainty as a function of R^2

Correlation coefficient (R^2)	Wind Speed correlation uncertainty
> 0.9	< 1 %
0.9 - 0.8	1 - 2%
0.7 - 0.6	3 - 5%

Source: *GL Garrad Hassan (2011)*

The uncertainty in future wind variability, in consideration of conducted studies NYSERDA (2010), should be approximately 1,4% (10 years) and 2,2% (25 years).

3.1.5 - Uncertainty in the wind flow simulation

The wind flow model is not always able to describe the wind behavior of the meteorological towers to the location of turbines. The terrain complexity, local roughness, the existence of obstacles and the distance of each turbine from the meteorological towers are among the factors that determine the magnitude of uncertainties. The range of uncertainty can be very wide, but a typical range is 3% - 6%.

3.1.6 – Other

Other sources of uncertainties in wind resource must be taken into consideration: Uncertainty in vertical wind extrapolation, uncertainty in the numerical simulation of wakes, uncertainty of wind data availability, etc.

3.2 - Energy Assessment Uncertainty

3.2.1 - Uncertainty due to Power curve

The power curve of a wind turbine is the curve that indicates the power output for each specific wind speed, and thus is one of the main parameters for estimating energy production. Due to terrain characteristics, the wind flow often displays different features from those in which the characteristic curve of the wind turbines had been designed. This may reflect different power curve output. Variables such as turbulence and topography can play a significant role in the variation of the power curve wind turbine.
When the power curve measurement test is carried out according to the international procedures, the uncertainty typical is between 4 and 6%. If the power curve measurement test is not made, the uncertainty of the power curve can be seen between 8% and 10%.

3.1.6 - Other

Uncertainty due to Electrical losses, Uncertainty due to Energy availability, etc.

4 UNCERTAINTY CALCULATION METHODS

There are two methods for calculating uncertainties: the deterministic method and the Monte Carlo analysis.
According to Fontaine et.al. (2007) the deterministic method is based around the assumptions that the different uncertainties are independent and that there is a linear relationship between the input uncertainties and the output uncertainty. The various individual uncertainties are summed using the Root Means Squared (RMS). This method does allow for the magnitude of the individual uncertainties to be determined.
The Monte Carlo method for estimating energy uncertainties is a stochastic method simulating the behavior of a physical system a large number of times. In a wind farm uncertainty analysis, these simulations produce wind farm outputs while randomly varying the uncertainties according to a defined probability distribution. The final uncertainty estimates are then determined from the distribution of the simulated outputs. This allows for non-linear relationships between the different uncertainties since the final uncertainty is not the result of summing the various uncertainties.

5 ENERGY AND PROBABILITY OF EXCEEDANCE

The methodology used to obtain the total uncertainty of the project, the various sources of uncertainty combined, may vary from company to company. Therefore, the same project, when carried out by more than one company, may produce different overall uncertainty regardless the use of the same data.
To properly estimate energy production, in addition to evaluate the project's uncertainties, it is essential to consider all energy losses as the electrical loss, unavailability of wind turbine, unavailability of electrical grid, wake loss, to name a few.
Following calculation of energy production and discounting all energy loss, the value of net Annual Energy Production (AEP) is attained.
The net AEP and total uncertainty determine, respectively, the mean and standard deviation for a normal Gaussian distribution. The absolute standard deviation is obtained by multiplying the total uncertainty by net AEP.
The calculated net AEP is the value of the energy production called P_{50}, central energy production estimate in the normal Gaussian distribution. This represents an energy value with a 50% probability of being exceeded.
In general, the probability of energy production distribution, assuming a normal Gaussian distribution is given by Eq.2.

$$f(E) = \frac{1}{\sigma\sqrt{2\pi}} e^{-(E-E_m)^2 / 2\sigma^2} \qquad \text{Eq.2}$$

Where:

$f(E)$ is the probability of production being equal to the E energy [%];

E_m is the mean of normal Gaussian distribution; The net AEP with a 50% probability to be exceeded; P_{50};

σ is the absolute standard deviation of the energy production estimate.

The Eq.2 is shown graphically in

Fig. 3 indicating the P_{50} value.

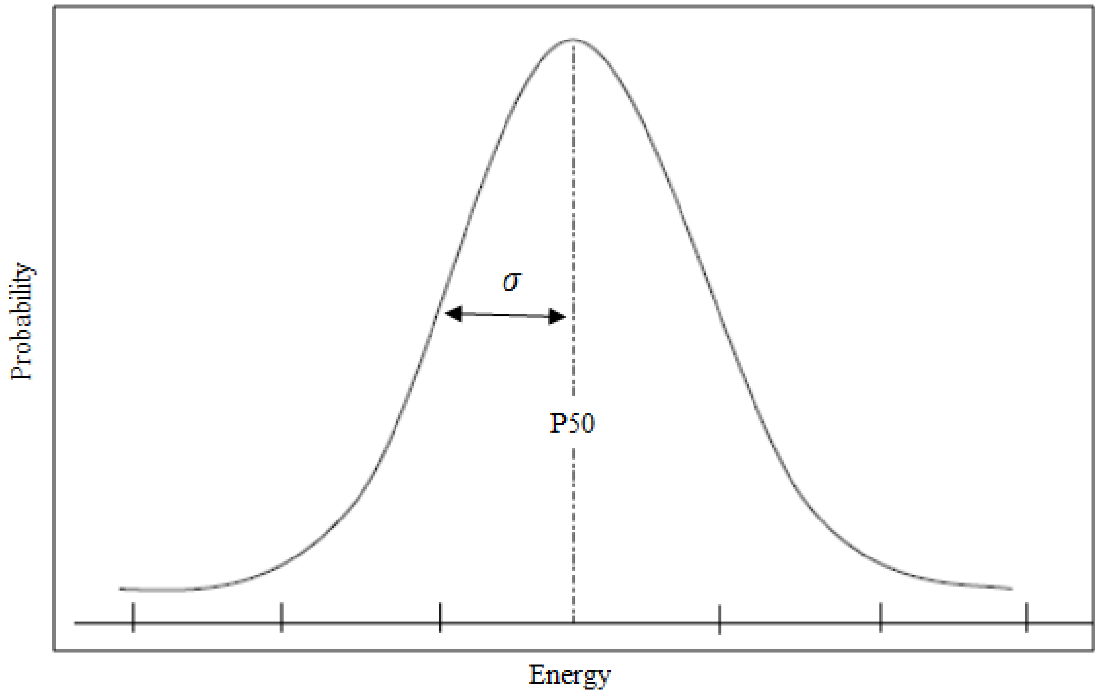


Fig. 3 - Normal Distribution – Energy production probability

To use tabulated values, they must be converted into a normalized Gaussian distribution.
To know energy production with a specific probability level, normal distribution tables for specific probabilities and the corresponding values of z need to be utilized.
With the P_{50} value, uncertainty total of the project and the z table probability, through of the Eq.3 it is possible to calculate the value in net energy production for the desired probability of exceedance.

$$P_x = P_{50} * (1 - z * Uncertainty_{Total}) \quad \text{Eq.3}$$

Where:

P_x is the net energy production to desired probability of exceeded.
$Uncertainty_{Total}$ is the total project uncertainty.
z is the value found in the probability table.

The z value is dependent on desired probability.

Table 3 shows z values for various probability levels.

Table 3 - Normal distribution table of specific probabilities and their corresponding *z* values

Probability of exceedance (%)	z
99	2,326
95	1,645
90	1,282
85	1,036
84	1,000
80	0,842
75	0,674
50	0
25	0,674
10	1,282
1	2,326

It is important to notice that the total uncertainty is related to the energy value in P_{50}.
The net AEP in P_{90} translates a 90% probability of being attained or exceeded.
It is recommended that the total uncertainty of the project should be around 15%.
The higher the value of total uncertainty, the higher the difference between P_{50} and the other levels of probability of exceedance.

5.1 – Examples of Probability of exceedance

Following are three examples with the same amount of energy in P_{50}, but with different values for total uncertainty. The energy values in P_{75} and P_{90} (75 % and 90 % probability of exceedance) are used to show the impact caused by overall uncertainty.

5.1.1 – Example 1: P50 of 120 GWh/year and total uncertainty of 10%

The Table 4 shows a project with energy in P_{50} equal to 120 GWh/year and 10% of total uncertainty. In this example, the energy values in P_{75} and P_{90} are respectively 7% and 13% lower than the value of energy in P_{50}.

Table 4 - Example 1: P50 of 120 GWh/year and total uncertainty of 10%

P50 (GWh/year)	Uncertainty	P75 (GWh/year)	P90 (GWh/year)
120	10%	112	105
Difference from P50		**-7%**	**-13%**

The Fig. 4 shows various levels of probability of exceedance for this example.

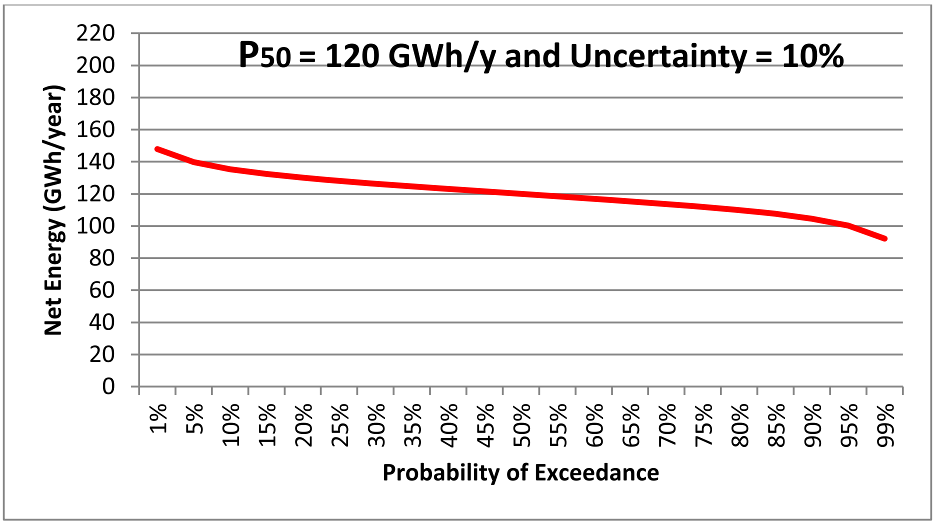


Fig. 4- Probability of exceedance: P50 of 120 GWh/year and Uncertainty of **10%**

5.1.2 – Example 2: P50 of 120 GWh/year and total uncertainty of 15%

The Table 5 shows a project with energy in P_{50} equal to 120 GWh/year and 15% of total uncertainty. In this example, the energy values in P_{75} and P_{90} are respectively 10% and 19% lower than the value of energy in P_{50}.

Table 5 - Example 2: P50 of 120 GWh/year and total uncertainty of 15%

P50 (GWh/year)	Uncertainty	P75 (GWh/year)	P90 (GWh/year)
120	15%	108	97
Difference from P50		**-10%**	**-19%**

The Fig. 5 shows various levels of probability of exceedance for this example

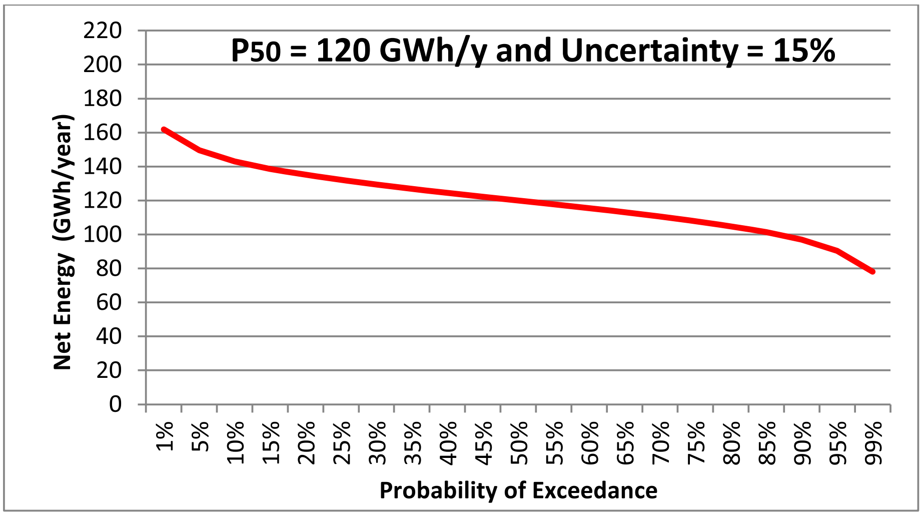


Fig. 5 - Probability of exceedance: P50 of 120 GWh/year and Uncertainty of **15%**

5.1.3 – Example 3: P50 of 120 GWh/year and total uncertainty of 30%

The Table 6 shows a project with energy in P_{50} equal to 120 GWh/year and 30% of total uncertainty. In this example, the energy values in P_{75} and P_{90} are respectively 20% and 38% lower than the value of energy in P_{50}.

Table 6 - Example 3: P50 of 120 GWh/year and total uncertainty of 30%

P50 (GWh/year)	Uncertainty	P75 (GWh/year)	P90 (GWh/year)
120	30%	96	74
Difference from P50		**-20%**	**-38%**

The Fig. 6 shows various levels of probability of exceedance for this example.

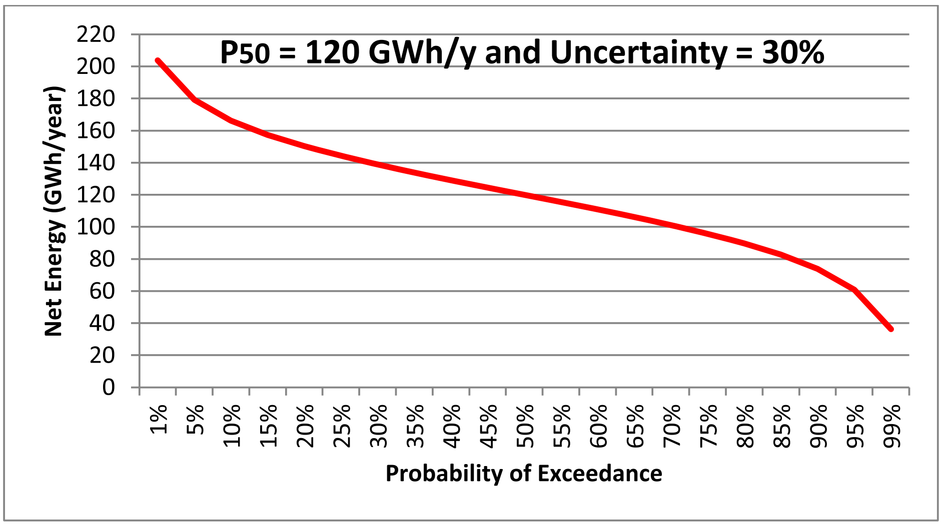


Fig. 6 - Probability of exceedance: P50 of 120 GWh/year and Uncertainty of **30%**

6 CONCLUSION

It is important to properly quantify the uncertainties of a wind project because they may represent significant variations in energy production. The uncertainty analysis is, therefore, paramount in assessing economic viability of a wind power project.
The extra costs for accurate wind monitoring are relative very small compared to a high investment in a wind energy project.
It is recommended to use first class anemometers and they need to be correctly calibrated.
Multiple measuring towers are very important to reduce the uncertainty. The maximum distance between proposed turbine location and meteorological tower should be lower than 6km for flat terrain and 2km for complex terrain.
The proper wind flow model is important to reduce the uncertainty. The linear model is recommended to flat terrain and neutral climatic conditions. For complex terrain, usually CFD model is recommended.
It is essential to define a standard methodology for the calculation of uncertainties in energy production on wind farms in order to avoid significant differences in the calculated energy from different independent certifiers.

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INNOVATION STRATEGIES OF ENERGY FIRMS

Costa-Campi, M.T.[1], Duch-Brown, N.[2], García-Quevedo, J.[3]

[1] *Department of Public Economics, Chair of Energy Sustainability and Barcelona Institute of Economics (IEB), University of Barcelona; Barcelona, Spain. E-mail: mtcosta@ub.edu*

[2] *Institute for Prospective Technological Studies, European Commission; Chair of Energy Sustainability and Barcelona Institute of Economics (IEB), University of Barcelona, Spain. E-mail: E-mail: nestor.duch-brown@ec.europa.eu*

[3] *Department of Public Economics, Chair of Energy Sustainability and Barcelona Institute of Economics (IEB), University of Barcelona, Barcelona, Spain. E-mail: jgarciaq@ub.edu (corresponding author)*

ABSTRACT

Investment by energy firms in innovation may have substantial economic and environmental impacts and benefits. Nevertheless, the amount of R&D investment in energy technologies appears to be low. Internal R&D is a main input and driver of the innovation process but innovation involves other activities such as capital purchases and other current expenditures related to innovation. While some papers have analysed the R&D activities of energy firms, few of them have examined the different types of innovation activities. The three main innovation activities in quantitative terms as well as because of their effects on the production of new products and services and processes are internal R&D, external R&D and the acquisition of advanced machinery, equipment or software. In addition, the objectives of innovation that firms want to achieve may not be the same for different innovation activities that may have different functions.

In this paper we first analyse the main characteristics of the firms regarding their decisions to invest in each of these three innovation activities and how these characteristics differ. In this analysis, we take the potential persistence of innovation activities into account. Second, we examine the role that different innovation objectives have on these decisions. Third, engaging in internal R&D, external R&D or acquire machinery may be the result of decisions not taken independently. Therefore we analyse whether there is some complementarity between these three innovation activities. To carry out the empirical analysis we rely on data for private energy firms from the Technological Innovation Panel (PITEC) for Spanish firms for the period 2004-2013. We use panel triprobit models to examine potential complementarity.

KEYWORDS: energy, R&D, innovation, regulation, complementarity

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1. INTRODUCTION

Investment by energy firms in R&D and innovation may have substantial economic and environmental impacts. Innovation appears to be a key issue for energy firms in facing the challenges regarding energy efficiency, mitigation of climate change and competitiveness (Anadon, 2012; Economics for Energy, 2013; OECD, 2011). Many reports and papers have emphasized that internal R&D in the energy industry remains low to meet these challenges (GEA, 2012, Costa et al., 2015a).

The empirical analyses of R&D and innovative behaviour of energy firms are constrained because of the lack of data (Anadon et al., 2011; Gallagher et al., 2012). Nevertheless, some recent papers have analysed the R&D determinants of the energy firms and the effects of the liberalisation of electricity markets on R&D investment (Costa et al., 2014; Jamasb and Pollit, 2008; Kim et al., 2012; Salies, 2010; Sanyal and Cohen, 2009; Sterlaccchini, 2012).

Internal R&D is the main input in increasing the stock of knowledge and innovating but innovation has many sources other than internal R&D. Firms may also purchase external R&D or even acquire machinery in order to innovate and to improve their technological level. The analysis of the choice of the R&D strategy has received considerable attention in the economics of innovation literature particularly regarding the decision to make or buy R&D. Nevertheless, to our knowledge, very few papers (Cohen and Sanyal, 2008) have examined the R&D choice of energy firms.

Therefore, the first objective of this paper is to examine the main characteristics of the firms regarding their innovation strategy choice. In this analysis we consider not only internal R&D and external R&D but also, using the OECD proposal on innovation expenditures classification, the acquisition of advanced machinery. Capital purchases may be an important way for energy firms to innovate, particularly in developing new or substantially improved processes. In this industry, suppliers play an important role in innovation.

In addition and following recent literature (Cassiman and Veugelers, 2006, Cruz-Cázares, 2013) we take into account potential complementarities between these three innovation activities. We examine whether the decisions are taken independently or, instead, firms combine different procedures in their innovation strategies.

Firms may undertake innovation activities for different reasons. The analysis of these reasons may help to understand R&D strategies and behaviour of the firms and the type of innovation that they want to achieve. The role of objectives is receiving an increasing interest in empirical research on innovation at the firm level (Costa et al., 2015b; Leiponen and Helfat, 2010).

The second objective of this paper is to examine the role that different innovation objectives – process innovation, product innovation, reducing environmental impact and meeting regulatory requirements- have on the decisions of energy firms to invest in internal R&D, external R&D or advanced machinery.

To carry out the empirical analyses we use the information provided by the Spanish Technological Innovation Panel (PITEC) for the period 2004-2013. The collection of the data for this panel is done with the information of the Community Innovation Survey carried for Spain that follows the guidelines of the Oslo Manual of the OECD (OECD, 2005).

After this introduction, the paper is organised as follows. In the next section, we provide a brief discussion on the motivation and reasons to innovate of energy firms in the current liberalised context. In this discussion we consider the different ways that firms use to innovate. The third section presents the database and some descriptive statistics regarding the engagement of firms in R&D and innovation and the objectives they pursue when innovating. The fourth section presents the specification of the model, explains the variables used and shows the results of the econometric estimations. The last section concludes.

2. INNOVATION STRATEGIES OF ENERGY FIRMS

The energy sector is undergoing a major transformation. Changes are occurring both upstream and downstream. This transformation of the energy sector is due to the combination of different technologies and the application of innovations coming from other sectors (Gallagher et al., 2012). Several authors maintain that the development of innovations in the field of energy requires a combination of several technologies and their use beyond their sector of origin (Bointner, 2014; GEA, 2012; Wangler, 2013).

Disruptive technological changes are affecting both the upstream and downstream thereby configuring a new totally different model from conventional energy supply. The emergence of renewable energy is displacing conventional generation and affecting the transmission and distribution system and the operation of the system. In turn, the incorporation of information technologies is allowing complete information to be given to consumers who are taking an active role on the demand side that will reverse the functioning of the system. Networks are no longer just physical channels of electricity flows but operate according to the new information available about users' consumption patterns. The management of large volumes of data (big data) explains the functioning of the sector under demand (pull) criteria. These new technological developments are allowing the provision of new energy services that can be expanded due to growing demand (Bointner, 2014; Grubler et al., 2012).

These changes are leading to a business innovation approach and require private companies to prioritize their investments in R&D given that public funds have proven to be insufficient on their own (Wiesenthal et al., 2012). Nevertheless, at the same time there is considerable interdependence between the two sources of funds, public and private (Jamasb and Pollitt, 2015). The literature emphasizes that innovation is the only way the industry can confront the changes that are taking place (Richter, 2013).

The result of this process of transformation is more intense competition and a constant search for competitive advantages by the companies. Entrants are more aggressive and innovative, a trend that is finally prevailing in the market. As Schumpeter (1942) pointed out, new entrants want to take over the market dominated by incumbents and thus increase their margins. The way to achieve this goal is through innovations that replace the services provided by the incumbents and thus win market share. Incumbents are expected to respond by increasing their investments to obtain new innovations that allow them to reverse the process. The result of this is more competition and leads to continuous improvements in technology that ultimately might become benefits for consumers.

The data provide evidence for this trend. After nearly two decades of falling R&D investment in the energy sector there is a recent recovery (Jamasb and Pollit, 2015; Bointner, 2014; Wiesenthal et al., 2012). The transformation experienced by the sector in providing services and launching new products onto the market seems to be the main driver of the recovery in R&D levels. Another explanation of this new trend is the strategy adopted by companies in the sector in their innovation processes, which is dominated by the weight of R&D performed externally with respect to the trend in other sectors. This could explain the low values found for R&D effort (Daim et al, 2011; Weisenthal et al, 2012) when strictly considering energy companies.

R&D and innovation investment made by energy companies seek to strengthen their competitive advantage according to the new coordinates of the energy market. Its objectives are to expand generation technologies particularly with renewable energy, which means they buy new technologies to other companies of the group or to the market, and to improve flexibility of process (purchase of new equipment) and product offering new services in accordance with the customer needs. In other words, increase their portfolio in the upstream and downstream markets. Its objectives also include reducing costs in the medium term (especially in CAPEX), increase innovation in operation and maintenance (OPEX), increase energy efficiency, adapt to new environmental legislation, innovate in network management power evacuation manageability and, finally, decentralization. To change, through constant innovation, the industrial processes yield to a disruptive technological transformation that causes to the firms to have to work bottom up, rather than top down as they were working so far (Daim et al., 2011).

This new model of technological development has led to the involvement of many companies in the energy innovation system from diverse sectors such as chemicals, electrical components, automotive and construction, among others. The literature recognizes that much of the research performed in the energy industry is carried out by suppliers of energy equipment and materials (Jacquier-Roux and Bourgeois, 2002). As a result of this interdisciplinary nature new innovation strategies are being carried out in the energy sector in recent years.

Business strategies that explain these innovation processes seem, regarding own sector reports (Eurelectric, 2013) and according to what literature points out (Daim et al., 2011), to be carried out in collaboration with other companies given the high costs and the diversity of activities and knowledge needed (hard and soft). The existence of high uncertainty in the sector (Sanyal and Cohen, 2008) combined with aspects such as capital intensive innovation requirements, the extended life of existing installations, the high time required for new technologies to mature and become competitive in the market may have caused the slowdown in the internal R&D ratios in energy firms (Gallagher et al., 2012). To face this situation, companies adopt a risk-sharing strategy conducting R&D externally allowing them to undertake various projects with the same amount of resources using the collaborative R&D as a hedge (Cohen and Sanyal, 2008), given the high volume of investments indicate in industry reports as necessary to advance in this transformation process (Eurelectric, 2013).

In the current context, external R&D seems to be almost an obligation due to the high number of skills needed to concur in new products and services that are demanded in the energy sector. Moreover, external R&D can offer the possibility of developing new technologies faster. The literature regarding environmental innovations shows that it is also more likely that they are made in a collaborative way (Horbach, 2008; De Marchi, 2012). Therefore, there are many factors that support the use of external R&D in the energy sector which could explain the low values of internal R&D of the sector.

Another strategy adopted by energy firms to innovate is to do it through the acquisition of machinery. This strategy assumes that the company relies on its external suppliers when introducing innovations (Bönte and Dienes, 2013). The main drawback is that the acquisition of innovations does not improve the ability to absorb knowledge of the company.

Internal R&D seems to be more effective when it is carried out together with external R&D and machinery acquisition. Large innovative companies not only develop their in-house R&D but also develop knowledge beyond their own institution. The reason to explain this behavior is the existence of complementarity between actions to innovate internal and externally (Cassiman and Veugelers, 2006).

3. DATA

Our dataset is a sub-sample of the Spanish Technological Innovation Panel (PITEC). PITEC includes exhaustive information on the characteristics and innovative activities of more than 12,000 Spanish firms for the period 2003-2013. While the EU wide CIS database offers information on cross section observations, the Spanish PITEC is able to identify firms in several waves and thus provides a large panel of innovative firms. From the full sample of firms, we select those that correspond to the energy industry as defined below.

Our operational definition of the energy sector includes all the activities related with the generation, transformation, distribution and retailing of energy. In PITEC, the data for the two divisions of the NACE Rev. 2 classification Electricity, gas, steam and air conditioning supply (NACE 35) and Water collection, treatment and supply (NACE 36) are aggregated. In order to separate water companies from energy companies, we rely on the fact that in Spain, due to the energy liberalisation process in the late nineties, all the gas and electricity companies are privately owned whereas almost all water companies are state-owned. Hence, to focus exclusively on energy firms we remove all the state-owned firms from the sample of utilities included in PITEC. In so doing we firmly believe that we are able to restrict the analysis to the activities included in the NACE 35. Unfortunately, however, we are not able to identify firms any further.

Since the focus of this paper lies in the innovative strategies of energy firms, a potential sample selection bias could arise if we do not control for the fact that some firms may just be not willing to innovate (Savignac, 2008; D’Este et al., 2012; Blanchard et al., 2013, Pellegrino and Savona, 2013). In order to focus exclusively on potential innovators we also exclude from the sample firms that meet the three following conditions: they have not innovated; they do not perceive any obstacle to innovation; and declare that they do no need to innovate.

Although PITEC provides information also for the year 2003, these data are incomplete. Nevertheless, since we use lags of independent variables for some variable in the estimations, we have also used the data for 2003 to avoid loss of information before removing all the observations corresponding to this particular year. After applying these filters, 543 observations are available for 91 energy companies forming an unbalanced panel for the period 2004-2013.

Table 1 shows the main characteristics of innovative firms in the Spanish energy industry included in the PITEC database. The data in the table show that they are on average big, with an average size of 615 employees, although the median lies around 280. Similarly, the average firm has been operating for 33 years but the dataset includes firms with more than 100 years in the industry and also recently created start-ups. Other characteristics include an indicator whether the firm belongs to a group or not, if the firm has participation of foreign capital in its ownership structure, and also if the firm has received public subsidies for R&D activities.

Table 1

Table 2 shows the descriptive statistics of our variables of interest, including firms that i) invest in internal R&D; ii) invest in external R&D and; iii) invest in the acquisition of machinery, equipment and software. Internal R&D comprises, as defined in Frascati Manual, all R&D performed within the enterprise in order to increase the stock of knowledge and use it to devise new applications. External R&D comprises the acquisition of R&D services from private or public organisations. Finally, in the category of advanced machinery we include, using the Oslo Manual (OECD, 2005) definition the acquisition of advanced machinery, equipment, computer hardware and software, and land and buildings that are required to implement product or process innovation. This category does not include the capital expenditures that are part of R&D.

More than half the energy companies (52%) reported performing internal R&D activities, while 41% reported subcontracting R&D activities in the period under consideration. Finally, only 23% of the firms have acquired specialised machinery, equipment or software. In addition, Table 3 shows that internal R&D and external R&D are highly correlated activities, while the relationship between internal and external R&D with the acquisition of machinery, equipment and software is quite low.

Tables 2 and 3

Table 4 shows the frequency of multi-strategy use by energy firms. The table indicates that 37.2% of firms do not perform any activity related to R&D. On the other hand, almost 20% of the firms use only one strategy. In this case, the most frequently used strategy corresponds to internal R&D activities (55% of the total), followed by the acquisition of machinery, equipment and software (34%) and external R&D activities (11%). However, when firms use two strategies simultaneously (which occurs in the 34% of the cases), the most frequently used pair of strategies is internal and external

R&D, observed in almost 80% of the cases. Hence, although external R&D activities are seldom used as an individual strategy, it turns out to be the most frequent complement for internal R&D activities. Finally, only in 9.4% of the cases the firms use all three strategies.

Table 4

Some recent contributions (Arqué-Castells, 2013; Raymond et al., 2010) emphasize the persistent character of innovative activities. Since our dataset includes a wide time period, Table 5 includes a rough computation of the transition probabilities for each strategy considered. The table indicates the probability that a firm i in period t will make the same choice regarding strategy j as in t-1. The table shows a high tendency to persistence in innovative activities. Transition probabilities are quite high, ranging from 90% in the case of internal R&D, to 76.5% for the acquisition of machinery, equipment and software.

Table 5

Finally, energy firms may use the different strategies at their disposal in different ways due to the fact that they may be facing different innovation objectives. PITEC allows for a comprehensive analysis of these objectives. In order to simplify the analysis, we have grouped them in four main categories: i) product innovation; ii) process innovation; iii) reducing environmental impact; iv) meeting regulatory requirements. Firms are asked to declare to what extent these different objectives are important, in a four level scale. Table 6 shows the share of firms for each objective and importance scale. In the four cases, the share of firms that declare the innovation objective is not important is consistently around 20%, with some deviations. However, more variation is found when looking at the share of firms that declare the objectives to be of high importance. In this case, only 9.6% of firms declare that process innovation is a highly important innovation objective whereas almost 40% of firms declare that reducing environmental impact is a highly relevant innovation objective.

Table 6

4. MODEL, ESTIMATION AND RESULTS

4.1. Model specification and variables

To analyse the decisions of the firms to invest in internal R&D, external R&D and acquisition of advanced machinery we use the following specification:

$$D_{it} = \begin{cases} 1 & \text{if } \alpha_1 D_{it-1} + \beta X + \gamma O + \delta C + \varepsilon_{it} > 0 \\ 0 & \text{otherwise} \end{cases} \tag{1}$$

In this equation, D corresponds to the dichotomous decision to engage or not in one of the three innovation activities considered. We have carried out three different estimations for each of these activities.

The independent variables of the three estimations are the same. We have included a lag of the dependent variable, a set of firm characteristics (X) and another set of variables regarding innovation objectives of the firms (O). In addition we take into account the potential existence of cost barriers to innovation (C).

First, recent analyses have underlined the persistence of innovation activities (Arqué-Castells, 2013; Raymond et al., 2010). The main reasons that explain this persistence is that R&D activities present high degrees of cumulativeness and irreversibility. This evidence is supported by our data. The transition probabilities of engaging in R&D activities are very high (Table 5). Therefore we have included lags of the dependent variables to control for this potential persistence.

Second, we consider, according to the literature on the determinants of the decision to engage in R&D and innovation in firms in general (Crepon et al., 1998; Cohen, 2010; Griffith et al., 2006) but also specifically in energy firms (Costa et al., 2014; Salies, 2010), size, age, public financing, foreign capital and belonging to a group as explanatory variables.

Since Schumpeter contribution, size has been always a key variable in the analysis of R&D and innovation at firm-level. Empirical results for energy firms show that larger firms are more likely to invest in internal R&D (Costa et al., 2004; Jamasb and Pollit, 2008; Salies, 2010; Sanyal and Cohen, 2009). Therefore we expect a positive relationship in our estimations. At the same time, it is expected that the benefits obtained from the external R&D are proportional to the size of the company while less conclusive is the literature regarding acquisition of advanced machinery.

The age of the firm may influence their decisions to invest in R&D and machinery. Recent papers show that the determinants to invest in R&D are not the same for young firms than for older firms (García-Quevedo et al., 2014) and that young firms rely more in the acquisition of machinery in order to innovate than older firms (Pellegrino et al. 2012).

We have also included the variable public funds in order to control for the effects of subsides on R&D and innovation decisions and to examine possible differences on their impact on the three innovation strategies. Public support is oriented to support, in principle, internal and external R&D but not the acquisition of advanced machinery. The existence or not of an additional effect of public support on private R&D has been frequently analysed in the empirical literature (David et al., 2000; Zúñiga-Vicente et al., 2014). In addition, most empirical analyses on the determinants of R&D (Griffith et al., 2006; Hall et al., 2013) include it in their models. To minimise endogeneity concerns due to public support is related with prior R&D and innovation performance, we have carried out the estimations with a lag of this variable following a common procedure in the literature (Costa-Campi et al., 2014).

We also control for the participation of foreign investors in the firm and whether the firm belongs to a group a firms. Both characteristics may influence the decisions to invest in R&D and advanced machinery and they have been frequently included in the analysis of R&D determinants. For instance, to belong to a group may help to overcome possible financial constraints.

Third, we include a set of variables regarding the objectives of innovation to examine the motives that drive decisions to invest in each of the three categories. The objectives are different by type to innovation and to fulfil them may require different innovation activities and strategies. Some of them may require investing in R&D while others may be achieved introducing new machinery or equipment.

We consider, according to the available information, four groups of motives for innovating. These are, first, objectives oriented to product innovation (e.g., to improve quality of goods and services, to increase range of goods and services, to enter in new markets), second, oriented to process innovation (to improve flexibility of production or service provision, to increase capacity of production and service provision, to reduce unit labour costs, to reduce consumption materials and energy). The third objective is to reduce environmental impact and, finally, we include also the objective of meeting environmental, health and safety regulations.

Fourth, a main obstacle to innovate is the existence of financial constraints. Therefore, we have included the potential lack of funds within the firm in order to examine whether it affects R&D and innovation decisions in energy firms and also to examine whether the effects are different for the three categories considered, internal R&D, external R&D and acquisition of advanced machinery. In principle, we expect that their effects on R&D investments may be greater than in the acquisition of machinery. R&D investments are characterised by the uncertainty of its results and returns. This uncertainty may explain the existence of financial constraints (Hall, 2002).

Finally and in addition to the explanatory variables, in the equations we take into account time effects in order to control for possible shocks arising from changes in the economic cycle as well as regulatory changes that may have affected R&D and innovation decisions of the firms.

4.2. Estimation and results

To carry out the estimations we use a trivariate probit model. For three binary variables D_1, D_2, and D_3, the trivariate probit model supposes that:

$$D_1 = \begin{cases} 1 & \text{if } \alpha_1 D_{1t-1} + \beta X + \gamma O + \delta C + \varepsilon_1 > 0 \\ 0 & \text{otherwise} \end{cases}$$

$$D_2 = \begin{cases} 1 & \text{if } \alpha_2 D_{2t-1} + \beta X + \gamma O + \delta C + \varepsilon_2 > 0 \\ 0 & \text{otherwise} \end{cases}$$

$$D_3 = \begin{cases} 1 & \text{if } \alpha_3 D_{3t-1} + \beta X + \gamma O + \delta C + \varepsilon_3 > 0 \\ 0 & \text{otherwise} \end{cases}$$

(2)

With

$$\begin{pmatrix} \varepsilon_1 \\ \varepsilon_2 \\ \varepsilon_3 \end{pmatrix} \rightarrow N(0, \Sigma)$$

In this case, the evaluation of the likelihood function requires the computation of trivariate normal integrals. As an example, consider the probability of observing $(D_1 = 0, D_2 = 0, D_3 = 0)$:

$$\Pr[D_1 = 0, D_2 = 0, D_3 = 0] = \int_{-\infty}^{A_1} \int_{-\infty}^{A_2} \int_{-\infty}^{A_3} \phi_3(\varepsilon_1, \varepsilon_2, \varepsilon_3, \rho_{12}\rho_{13}\rho_{23})\, \mathrm{d}\varepsilon_3 \mathrm{d}\varepsilon_2 \mathrm{d}\varepsilon_1$$

where $A_i = \alpha_0 + \alpha_1 D_{it-1} + \beta X + \gamma O + \delta C$, ϕ_3 is the trivariate normal p.d.f., and ρ_{ij} is the correlation coefficient between i and j. We rely on the triprobit command in Stata to perform the estimations, an estimation procedure that uses the GHK (Geweke-Hajivassiliou-Keane) smooth recursive simulator to approximate these integrals and estimate the coefficients by means of simulated maximum likelihood.

In the estimations we have begun with a parsimonious specification. In the first estimations we have only included the structural characteristics of the firms. After that, in the second estimations we expand this specification and we also include the objectives for innovating and the potential financial obstacles to innovate. Finally, in the third set of estimations, we include for the three dependent variables their corresponding lags. The main results from these estimations are as follows (Tables 7 and 8).

Tables 7 and 8

The estimations show the persistence of R&D decisions in energy firms, similar to the empirical analyses of manufacturing activities. This persistence also takes place in investment in advanced machinery which suggests that innovation in energy firms require a continuous flow of capital expenditures to improve the technological level of their equipment.

Regarding firm characteristics, the results show significant differences for the three innovation activities. First, larger firms in the energy industry are more likely to invest in internal R&D and to acquire R&D services. Instead, this variable is not significant in the acquisition of advanced machinery. This result confirms the importance of a certain size in undertaking R&D projects while firms of all sizes acquire advanced machinery.

Second, age does not seem to have a significant influence on R&D and innovation decisions although older firms seem to be more likely to acquire advanced machinery. The result regarding R&D decisions suggests both incumbents and new entrants undertake R&D activities.

Third, public funds have a positive effect particularly on the decision to invest in R&D within the firm. In addition, there is also some evidence of a positive relation with external R&D while this parameter is not significant in any of the estimations of the determinants of the decision to invest in advanced machinery. This result is consistent with the orientation and objectives of public policy to support R&D activities, internal and external.

Fourth, energy firms with participation of foreign capital are more likely to engage in internal R&D and in acquiring R&D services. Finally, to belong to a group of firms increases the probability to acquire advanced machinery but it has no effects on the decision to invest in internal R&D or to buy R&D services.

The results of the estimations also show significant differences in the effects of the objectives of innovation on decisions to engage in the different innovation activities. R&D, both internal and external, is particularly related with environmental motives and to meet regulatory requirements. Instead, the process innovation objective is the main factor in the acquisition of advanced machinery. These results suggest that R&D and to acquire advanced machinery are intended to address different technological and market challenges. In particular, it emphasizes that to fulfil the objective of reducing environmental impact in the energy sector requires undertaking R&D projects and it is not only achieved with the introduction of new machinery and equipment.

The results also show that financial obstacles do not seem to be an important barrier hampering innovation in the energy industry (Salies, 2010) in contrast to the empirical evidence that has stressed that firms face financial obstacles to innovation activities (Hall, 2002; Popp and Newell, 2012; Blanchard et al., 2013).

Finally, the results also suggest the existence of complementarities between internal and external R&D. In the three sets of estimations, the correlation coefficients of the error terms are positive and highly significant. These results support, as recent literature on R&D decisions show, the existence of interdependencies between doing internal R&D and acquiring R&D services. Instead, there is no such interdependence between the decisions to perform R&D and to acquire advanced machinery. The decision whether to invest in R&D or in advanced machinery is independent which again suggest that they pursue different innovation objectives. Nevertheless, some caution is required in this analysis of potential interdependence because we are not testing formally the existence of complementarities and also because the correlations also arise if there are unobservable firm-specific factors that affect R&D and innovation decisions.

5. CONCLUSIONS

The energy industry is experiencing substantial transformation and technological change. Investment in innovation by firms has an important role to improve energy efficiency, competitiveness and to face the challenges related with climatic change.

The objective of this paper is to improve our understanding of the innovation activities of energy firms. We have, first, examined the main characteristics of energy firms regarding their choice of innovation strategy. In this analysis we have considered the main three innovation activities, internal R&D, external R&D and the acquisition of advanced machinery. Second, we have analysed the role that different innovation objectives play in the decisions of energy firms to invest in R&D and innovation.

The main conclusions from the econometric analysis carried out are as follows. First, innovation investments are highly persistent. This persistence happens not only in internal and external R&D decisions but also in the acquisition of advanced machinery. Second, the characteristics of the energy firms that invest in each of these innovation activities are different. Larger firms, with participation of foreign capital and that receive public subsidies are more likely to invest in internal R&D. Instead, these characteristics are not significant in the estimation regarding the acquisition of advanced machinery. Third, financial costs do not seem to be an important barrier in the energy industry to engaging in innovation.

The results also show that there are significant differences in the effects that the objectives of innovation have on decisions to engage in the three different innovation activities. While R&D, internal and external, is addressed to environmental objectives and meeting regulatory requirements, the objective of process innovation is the main driver of the acquisition of advanced machinery and equipment.

Finally, the results suggest the existence of interdependencies between doing internal R&D and acquiring R&D services. Instead, the decision whether to invest in R&D or in advanced machinery seem to be independent and intended to address different technological challenges.

The results have some policy implications regarding how to foster innovation in the energy industry. First, our results suggest that public support to private R&D as well as environmental regulation requirements are positively related with R&D engagement of private firms. The literature shows that environmental and technology policies are more effective when they work in tandem (Popp et al., 2010). Second, to face the innovation challenges requires that energy firms combine internal and external R&D sources and increase cooperation on innovation between the firms in the energy sector and those in other industries and also with public institutions and agents.

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Table 1. Firms' characteristics: descriptive statistics

	N	**Mean**	**Std. Dev.**	**Min**	**Max**
Size	543	615.1	1078.5	1	7900
Age	484	33.4	33.5	0	113
Public funds	543	0.403	0.491	0	1
Foreign capital	543	0.193	0.395	0	1
Group	543	0.670	0.471	0	1

Table 2: Dependent variables: descriptive statistics

	N	Mean	Std. Dev.	Min	Max
Internal R&D	543	0.516	0.500	0	1
External R&D	543	0.407	0.492	0	1
Machinery, equipment or software	543	0.232	0.423	0	1

Table 3: Correlation matrix of dependent variables

	Internal R&D	External R&D	Machinery
Internal R&D	1		
External R&D	0.615	1	
Machinery, equipment or software	0.105	0.113	1

Table 4: Frequency of multi-strategy use

N of strategies	Freq.	Percent
0	202	37.2
1	106	19.5
2	184	33.9
3	51	9.4

Table 5: Transition probabilities

	Prob.
Internal R&D	0.895
External R&D	0.878
Machinery, equipment or software	0.765

Table 6: Importance of innovation objectives

	Not important	**Low**	**Medium**	**High**
Product	21.8	31.9	33.0	13.4
Process	18.0	35.8	36.5	9.6
Environment	23.4	10.1	27.9	38.6
Regulations	24.1	12.9	32.8	30.2

Table 7. Triprobit estimation: characteristics, objectives and cost barrier

VARIABLES	(1) IntRD	(2) ExtRD	(3) Machinery	(4) IntRD	(5) ExtRD	(6) Machinery
Ln(size)	0.336***	0.289***	0.0185	0.339***	0.292***	0.00287
	(0.0498)	(0.0468)	(0.0467)	(0.0522)	(0.0504)	(0.0480)
Ln(age)	-0.124*	-0.0574	0.140**	-0.0839	-0.0251	0.125*
	(0.0740)	(0.0667)	(0.0676)	(0.0776)	(0.0720)	(0.0686)
Public funds (t-1)	1.487***	0.937***	0.0953	1.502***	0.802***	-0.0685
	(0.154)	(0.140)	(0.149)	(0.170)	(0.154)	(0.161)
Foreign capital	0.487***	0.516***	0.233	0.540***	0.490***	0.151
	(0.179)	(0.165)	(0.164)	(0.192)	(0.179)	(0.169)
Group	-0.113	-0.0259	0.737***	-0.0967	-0.0977	0.699***
	(0.180)	(0.174)	(0.201)	(0.195)	(0.188)	(0.211)
Product				0.270	-0.112	0.148
				(0.190)	(0.174)	(0.164)
Process				-0.535***	0.00867	0.449***
				(0.203)	(0.172)	(0.170)
Environment				0.225	0.771***	0.0576
				(0.207)	(0.191)	(0.196)
Regulation				0.713***	0.434**	-0.133
				(0.202)	(0.185)	(0.194)
Cost barrier				0.232	0.175	-0.244
				(0.351)	(0.318)	(0.299)
Constant	-1.592***	-1.715***	-1.042***	0.893***	-0.0974	-0.102
	(0.387)	(0.360)	(0.357)	(0.131)	(0.0942)	(0.0830)
Observations	472	472	472	472	472	472
athrho12	0.919***			0.893***		
	(0.124)			(0.131)		
athrho13	-0.111			-0.0974		
	(0.0926)			(0.0942)		
athrho23	-0.0791			-0.102		
	(0.0786)			(0.0830)		

Standard errors in parentheses. ***, **, and * denote significance at the 1%, 5%, and 10% level respectively. All regressions include time-dummies to control for year-specific effects. The multivariate probit (assuming normality of the error terms) provide with ρ, a correlation parameter that inform about the covariation of the error terms of the two decisions. If ρ=0 the probability of one decision is independent of the probability of the other decision

Table 8. Triprobit estimation: characteristics, objectives and cost barrier with lagged dependent variables

VARIABLES	(1) IntRD	(2) ExtRD	(3) Machinery
IntRD (t-1)	2.120***		
	(0.232)		
ExtRD(t-1)		1.893***	
		(0.196)	
Machinery (t-1)			0.839***
			(0.165)
Ln(size)	0.309***	0.252***	-0.0143
	(0.0697)	(0.0668)	(0.0497)
Ln(age)	-0.0517	0.0216	0.0502
	(0.0991)	(0.0917)	(0.0734)
Public funds (t-1)	0.599**	0.127	-0.0388
	(0.241)	(0.215)	(0.167)
Foreign capital	0.458*	0.380*	0.107
	(0.244)	(0.212)	(0.175)
Group	0.0951	0.0182	0.500**
	(0.253)	(0.242)	(0.219)
Product	0.379	-0.119	0.261
	(0.241)	(0.229)	(0.169)
Process	-0.485*	0.0499	0.481***
	(0.250)	(0.206)	(0.170)
Environment	0.442*	0.737***	-0.0842
	(0.256)	(0.232)	(0.209)
Regulation	0.515**	0.384	-0.223
	(0.255)	(0.240)	(0.206)
Cost barrier	-0.0716	0.203	-0.275
	(0.430)	(0.399)	(0.321)
Constant	-2.665***	-2.460***	-0.479
	(0.582)	(0.539)	(0.420)
	431	431	431
athrho12	0.735***		
	(0.188)		
athrho13	-0.109		
	(0.117)		
athrho23	-0.0952		
	(0.0799)		

Standard errors in parentheses. ***, **, and * denote significance at the 1%, 5%, and 10% level respectively. All regressions include time-dummies to control for year-specific effects. The multivariate probit (assuming normality of the error terms) provide with ρ, a correlation parameter that inform about the covariation of the error terms of the two decisions. If ρ=0 the probability of one decision is independent of the probability of the other decision.

Evaluation of policies and incentive actions to foster technological innovations in the electricity sector - structuring criteria

Carlos Henggeler Antunes[1,3], Luís Dias[2, 3], Guilherme Dantas[4], João Mathias[5], Lucca Zamboni[6]

[1] *Dept. of Electrical and Computer Engineering, University of Coimbra, Portugal, ch@deec.uc.pt*
[2] *Faculty of Economics, University of Coimbra, Portugal, lmcdias@fe.uc.pt*
[3] *INESC Coimbra, Coimbra, Portugal*
[4] *GESEL, Federal University of Rio de Janeiro, Brazil, guilhermecrvg@yahoo.com.br*
[5] *GESEL, Federal University of Rio de Janeiro, Brazil, mathias@ie.ufrj.br*
[6] *EDP Brasil, Brazil, lucca.zamboni@edpbr.com.br*

ABSTRACT

The promotion of a reliable and sustainable power system has as key drivers the development of smart grids associated with demand-side management schemes, diffusion of electric mobility, accommodation of larger shares of distributed generation, in particular microgeneration and the introduction of storage systems. In addition, these technological development vectors represent new business opportunities for several players (utilities, retailers, ESCOs, aggregator entities, etc.), which should be considered by regulatory guidelines accounting for technical efficiency, economic feasibility and tariff affordability.

The technical and economic characteristics of the electricity sector (capital intensive, undifferentiated product, regulated tariffs, almost inelastic demand, need of instantaneous balance between supply and demand, etc.) do not induce that the process of technological innovation happens in an endogenous manner within the sector dynamics. Therefore, public policies have a role to play in this process.

This communication presents an approach using Problem Structuring Methods to frame the problem of analyzing and evaluating technological innovations and associate incentive policies in the electricity sector. The results of this structuring phase using Soft Systems Methodology suggest a large number of issues that were organized as a hierarchy of objectives. These objectives will correspond to the criteria of a Multicriteria Decision Analysis methodology devoted to assessing the potential courses of action promoting technological innovation. This methodology should provide decision support to policy and decision makers to shape policies aimed at fostering more reliable and sustainable electricity systems.

KEYWORDS: Electricity sector, technological innovations, problem structuring, multicriteria decision analysis, innovation policies

1 INTRODUCTION

Investments associated with technological innovations to guarantee the reinforcement, expansion and modernization of electrical network infrastructures to satisfy a growing demand with security, quality and less environmental impacts should be analyzed taking into account distinct perspectives of evaluation. The offer of a sustainable and reliable electricity system has as an important driver the evolution towards smart grids, associated with demand side management schemes, increase of distributed generation, in particular micro-generation, diffusion of electric mobility and introduction of storage systems. Additionally the technological development vectors represent new business opportunities, which should be considered by regulation guidelines to make viable the smart grids evolution process in the pursuit of technical efficiency, economic viability and tariff moderation.

The diffusion of smart grids is not just a technological innovation, but a technological transition is at stake. In this context, the analysis of the technological variables arising in this process is necessary, and the interests of the different stakeholders involved in the process should be considered. The techno-economic characteristics of the electricity sector (capital intensive, undifferentiated product, regulated tariffs, almost inelastic demand, need of an instantaneous balance between supply and demand, etc.) do not induce that the innovation process occurs endogenously to the sector dynamics. Therefore, public policies are required to foster this process.

The complexity of the study of innovation technologies and incentive policies associated stems mainly from the need to take into account aspects of distinct nature (technological, economic, financial, social, regulatory), several of them of intangible nature, in the evaluation models. Therefore, the structuring of the problem characteristics is an essential step to develop such models. Since decision making in the energy sector should take into account variables of heterogeneous nature and stakeholders of different spheres, traditional evaluation methods such as cost-benefit analysis, do not enable the explicit consideration of all elements involved on a consensual and realistic basis. This limitation is essentially due to the difficulties of monetizing several aspects of the problem, as well as making transparent the trade-offs to be established between the multiple perspectives the evaluation should encompass.

In this context, multi-criteria decision aid (MCDA) methodologies are particularly adequate to deal with a vast range of problems, in which potential alternatives (courses of action) should be judged according to different evaluation axes that are explicitly considered in the model. MCDA models enable to include evaluation criteria of different nature, which are generally conflicting and incommensurate, taking into account the points of view of different stakeholders, each one displaying in the decision process his/her own values, preferences and criteria.

This paper deals with the importance of problem structuring as an essential step of the analysis, enabling to unveil a deeper understanding of the problem, as well as the essential elements that should be included in the MCDA model through the interaction with the stakeholders, in order to provide decision support in the appraisal of policies and actions of incentive to technological innovations in the electricity sector.

2 PROBLEM STRUCTURING METHODS – SOFT SYSTEMS METHODOLOGY

As it is recognized by several authors (Bana e Costa and Beinat, 2011; Belton et al. 1997; Checkland and Scholes, 1990; Diakoulaki et al., 2006; Keeney, 1992; von Winterfeldt e Fasolo, 2009), the problem structuring phase should constitute the first step, and one of the most important ones, in decision support processes. The real-world applications emphasize the critical nature of problem structuring in order to gather in an organized manner all the relevant information, improve the understanding of the overall decision situation and clearly define the problem to be tackled.

In general, real-world problems arise in complex and ill-defined contexts. Therefore, it is necessary to identify the essential characteristics of the decision situation, establish the scope and the boundaries of the analysis, recognize the stakeholders involved, as well as their main motivations and objectives, and understand which actions can be carried out (Bana e Costa and Beinat, 2011). This analysis enables to offer all participants into the process of a common view and an operational basis from which the identification of the fundamental points of view, the operational criteria, and the potential actions to be evaluated will emerge.

Several Problem Structuring Methods (PSM) have been proposed for structuring complex decision situations (Rosenhead, 1996). According to Rosenhead (1996), these situations for which PSM are particularly useful area characterized by multiple actors and multiple perspectives, non-consensual or even antagonistic interests, different measurement units of the impacts, evaluation aspects of intangible nature, and uncertainty over several elements of the decision situation. PSM present two essential characteristics: facilitation and structuring. Facilitation aims to offer an environment in which the debate between the participants is duly oriented according to the components of each specific PSM, enabling to clarify the understanding of the decision situation. Structuring refers more generally to the process of organization of the elements unveiled during debate, in order to enable advancing on a common basis of knowledge about the problem, thus contributing to improve the quality of the decision making process.

Each PSM proposes a particular representation of the decision situation to: enable the analysis of different perspectives, be cognitively accessible even for actors less familiarized with the topic, work in an interactive manner reflecting the evolution of debate and learning of the actors, enable identifying and compromise of partial improvements rather than requiring a global solution. These requirements do not entail mathematical models or methods (Mingers and Rosenhead, 2004). PSM foster a better understanding of the role of each actor, his/her degree of intervention and power to influence decisions, the relationships between the different actors and the identification of their values, objectives e concerns. The application of PSM to decision situations in the energy sector has had some recent developments, with emphasis on Soft Systems Methodology (SSM). SSM is a general system analysis method developed from systems engineering concepts (Checkland and Scholes, 1990; Checkland and Poulter, 2006). Neves et al. (2004) used SSM to structure a problem of evaluation of initiatives for the promotion of energy efficiency. Ngai et al. (2012) used SSM to identify opportunities in management support of rational use of energy in textile manufacturing processes. Coelho et al. (2010) also used SSM to study problems in urban energy planning.

The main reasons for the selection of SSM to carry out this study are rooted on our experience in problem structuring of problems in the energy sector (Neves et al., 2004; Coelho et al., 2010), its flexibility in the description of the decision situation, including the definition of the role of each participant, his/her degree of involvement and intervention capacity, and the relationships between the participants. The SSM approach offers a systemic framework to carry out process analysis in which technological issues and the intervention of decision makers are interdependent. SSM was developed to use systems engineering concepts to complex and ill-defined problems in which the multiple inter-related issues are not clearly defined (Checkland and Scholes, 1990; Checkland and Poulter, 2006), with multiple world views and then multiple conflicting objectives pertaining to the stakeholders.

The SSM approach enables the linkage between the structuring and alternative evaluation steps, contributing to shed light on the main issues of distinct nature that should be incorporated in MCDA models. The approach to problems using SSM is carried out, in general, using a search process consisting of seven stages as illustrated in Fig. 1. In this diagram a clear distinction is made between the real world and the (conceptual) systems world. The line separating stages 1, 2, 5, 6 and 7 from stages 3 and 4 indicates that the SSM analysis addresses two main concerns: one associated with the real world and another one focused on the systems world in a systemic perspective.

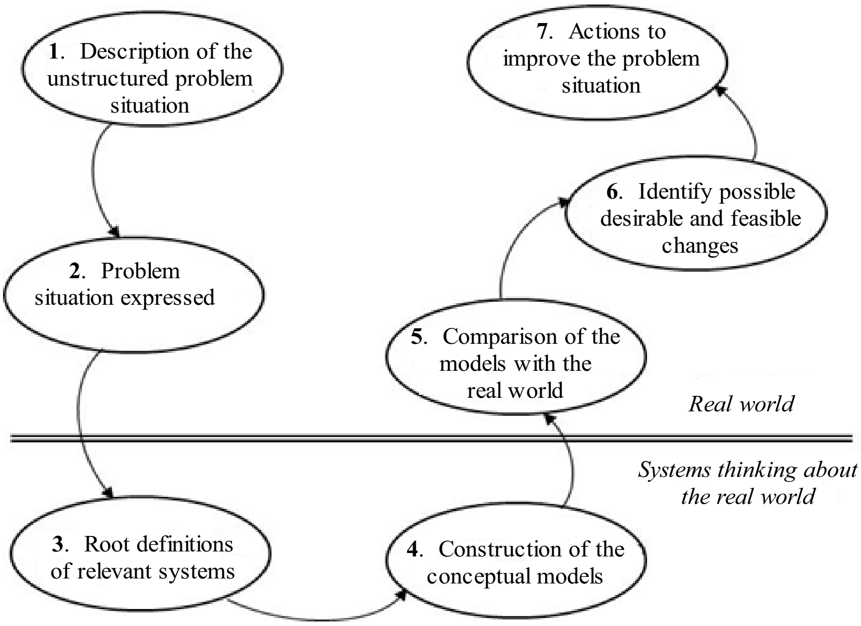

Figure 1 – The steps of SSM

The SSM approach begins with the identification of a real world situation that is considered problematical by some stakeholder. The description of the situation aims at making a diagnosis of the existing situation, identifying the participants and the problem nature. The most common strategy is the graphical representation of the problem under study. This graphical representation, called "rich picture", includes all stakeholders and their relationships in order to offer a broad vision of the problem. In stages 3 and 4 the SSM approach builds the conceptual models. This implies having a clear and objective definition of the system to be modeled, which is known as root definition, whose construction should be guided to contain the following components (CATWOE): Customers, Actors, Transformation process, Weltanschauung (world view), Owner, and Environmental constraints (Table 1).

From the root definition the conceptual model is developed as simple as possible to accomplish the transformation described in stage 3. This model is constituted by a set of activities conceived as a transformation process and connected by logical dependencies (Checkland and Tsouvalis, 1997). The conceptual models should then be validated by comparing them with a formal system. A formal system should possess the following elements: Purpose/mission; Performance measure; Decision making process; Sub-systems; Interaction with the environment; Physical and human resources; Continuity. This model should also include the monitoring and control activities to assess the system efficacy, efficiency and effectiveness (Checkland and Poulter, 2006).

Once the model is developed and returning to the real world problem situation, in stage 5 the SSM approach makes a comparison between the model and the real world. In this comparison stage, the participation of the stakeholders is of utmost importance in order to generate debate on possible changes that desirably may occur to improve the situation. Based on the comparisons, in stage 6 it is possible to identify change proposals that will be necessary to introduce in the real system processes and structures, which will be implemented in stage 7. The success of the implementation requires that change proposals are desirable and feasible.

Table 1 – Root definition - CATWOE

C	*Client* – the immediate beneficiaries or victims of the system results.
A	*Actors* – the participants in the transformation, i.e. those who carry out activities within the system.
T	*Transformation* – the core of the human activity system, in which some inputs are converted in outputs and given to the clients. Actors play a role in this transformation process.
W	*Weltanschauung* (world view) – the perspective or point of view that makes sense of the root definition being developed.
O	*Owner* – the individual or group responsible for the proposed system. He/she has the power to modify or even stop the system, overlapping other system actors.
E	*Environmental constraints* – the human activity systems work under some constraints imposed by the external environment, as legal, physical or ethical constraints.

3 MULTI-CRITERIA DECISION AIDING

Rather than trying to convert all aspects important for a decision into a single "currency", which is often difficult and subject to controversy, the paradigm of MCDA considers explicitly several evaluation criteria (Dias el al. 2015). According to Bouyssou (1993) there are three main advantages of adopting this paradigm: it allows a solid base for dialogue by acknowledging the concerns of all stakeholders, encouraging joint ownership of the evaluation models, it breaks down the problem thus facilitating the definition of assessment instruments and uncertainty modelling, and it invites decision makers to consider any choice as a compromise between conflicting objectives, since there is rarely an option better than all the rest on every evaluation criterion. The areas of energy and environment have been a fertile ground for the application of MCDA approaches, as can be witnessed in several books and reviews (Diakoulaki et al., 2016; Ehrgott and Stewart, 2010; Huang et al., 2011; Linkov and Moberg, 2012; Wang et al., 2009).

There are three main stages of a decision process under an MCDA paradigm: problem structuring, construction of the evaluation model, and exploitation of the model.

The stage of structuring the problem is the basis for all analyses that ensue. Structuring entails defining what the problem is, what the alternatives and their consequences are, and what criteria should be used to evaluate alternatives. Keeney (1992) sustains that decision makers should focus on objectives first and then alternatives, mainly because this can foster creativity in designing new alternatives and ensures the evaluation criteria are aligned with an individual's or an organization's objectives. The use of PSM such as SSMs can be quite helpful to the process of identifying relevant actors and objectives (Neves et al., 2009).

The stage of constructing the evaluation model entails, first, evaluating the performance of each alternative according to each one of the different evaluation criteria. These performances can be measured on quantitative or qualitative scales. Criteria such as costs or pollutant emissions can be measured quantitatively. If a direct indicator is not available for the assessment in question, it is possible to use an indirect indicator. For instance, acres of forest destroyed can be an indirect indicator for loss of biodiversity. On the other hand, criteria such as degree of opposition of the population, or aesthetic perception of the landscape, will usually be assessed on a qualitative scale using levels such as negligible, significant, etc., through a precise description (a descriptor table) for the meaning of each level, to avoid different interpretations of the same words (Keeney and Sicherman, 1983).

Once a performance table is built summarizing the assessment of each alternative on each criterion, the following step in an MCDA study consists in deriving a recommendation using an appropriate aggregation method. There are three main pathways to perform an aggregation of single-criterion performances (Roy, 1985): obtaining an overall synthesis value (allowing to rank all the alternatives), obtaining a binary relation (not necessarily complete) comparing alternatives in a pairwise way, or obtaining answers to simple questions from the decision maker in the course of an interactive questioning protocol able to identify the most interesting alternatives at its end.

4 PROCESS FOLLOWED TO STRUCTURE OBJECTIVES

Recognizing and structuring decision objectives is essential to reach adequate recommendations, but often decision makers fail in this crucial step (Bond et al. 2010). Bana e Costa and Beinat (2011) and Keeney (1992) presented methodologies to elicit and structure objectives (or points of view) for an MCDA process. Such methodologies allow identifying the so-called fundamental objectives set. Each fundamental objective should be controllable, essential, concise, specific and understandable. Fundamental objectives often comprehend different sub-objectives, but it should be possible to assess alternatives on each fundamental objective, one at a time, independently of the other fundamental objectives. As a set the fundamental objectives should be complete but not redundant.

Fundamental objectives are not means to a higher-level concern. They represent an end in themselves. For instance, let us consider an objective of reducing the consumption of electrical energy. Asking the decision maker why is this objective important the answer might reveal the objective of reducing costs to consumers, or the objective of reducing greenhouse gas emissions, or both. This distinction between means-objectives and end-objectives is important. For instance, if the fundamental objective is to reduce greenhouse gas emissions then not only the consumption of electricity matters, but also the carbon intensity of the country's mix.

The construction of a hierarchy of objectives can be carried out using a top-down or a bottom-up approach (Keeney, 1992; Parnell et al. 2013). The top-down approach starts by identifying the fundamental objectives, which are then decomposed into lower level sub-objectives, down to the relevant attributes of the alternatives. Its main advantage is that it focuses on the main concerns behind the evaluation process, but it risks omitting a few relevant sub-objectives. A bottom-up approach starts by considering a set of many attributes of the alternatives that are considered to be relevant for the decision process, and then these attributes are successively coalesced into higher-level objectives. Its main advantage is to allow discussing objectives at a more concrete and understandable level, but it risks missing a broader perspective.

The strategy followed in the current work sought to combine the advantages of bottom-up and top-down approaches. First, a bottom-up approach was followed to inform the definition of a set of fundamental objectives. Then, a top-down approach ensured no relevant aspects were missing.

Fig. 2 presents the rich picture for the problem of evaluation of policies and incentive actions to foster technological innovations in the electricity sector with a focus on the development of smart grids. This diagram results from information gathered in the scientific literature, namely a thorough revision of the practices in eighteen countries, technical visits to several entities in Portugal, France, Italy and Germany, as well as discussions held at the International Seminar on "Challenges of Regulation in the Electricity Sector" (Coimbra, 12-13 February 2015). This information has been discussed among experts at the R&D Institute INESC Coimbra and then discussed at GESEL-UFRJ, EDP Brazil, ONS (Transmission Network System Operator, Brazil) and ANEEL (Brazilian regulator of the electricity sector) in November 2015.

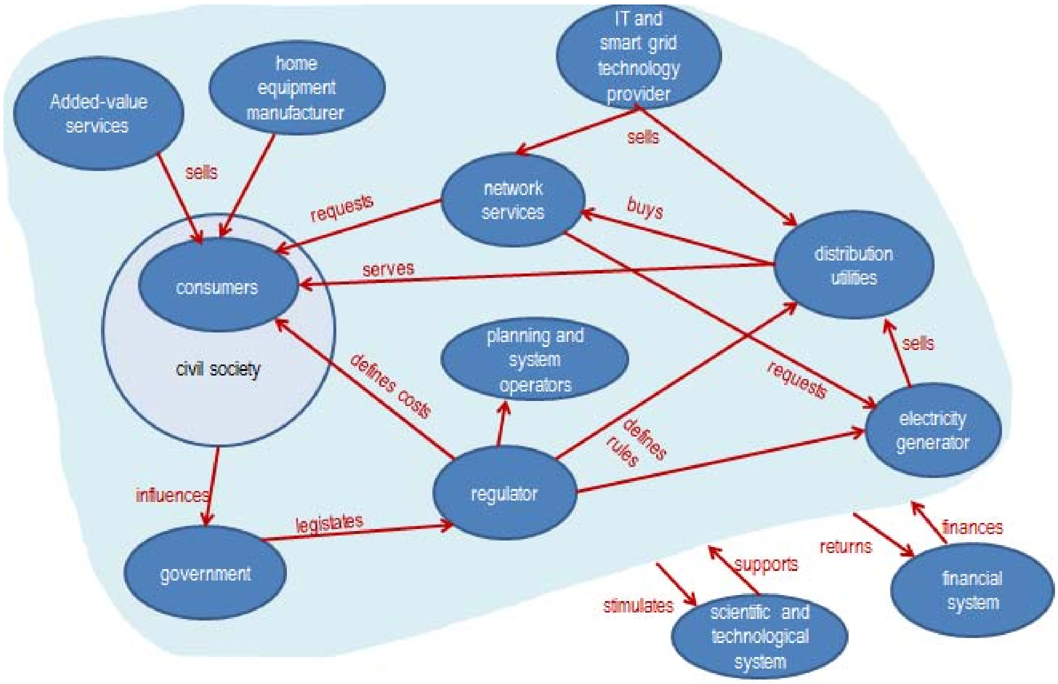

Fig. 2. Rich Picture

The following actors have been identified:

- **Consumers** are the final clients of the electricity distribution service; they may be individuals or companies.

- Consumers are a relevant part of the **Civil Society**, which also includes organizations representing them such as consumer associations, industry associations, or even the media, all influencing government policies.

- The **Government**, at different territorial levels, determines the energy policies at large.

- The **Regulator** has a mediation role between all the stakeholders in the electricity sector. This actor defines the rules that apply to generators, distributors and retailers of electric energy, also with the power to define the costs (or part of the costs) seen by the consumers in the tariffs.

- **Generators** of electric energy invest in generation capacity and sell energy in the market.

- **Distributor** / Retailers (in some countries these can be the same of different entities) supplies energy to consumers, charging the availability of service (power tariff wherever it exists) and the energy sold. It can buy network services to other entities to better achieve its aims, ensuring the best way to manage and satisfy demand.

- **Planning and operation entities** include those that have the mission of the long-term planning of the electricity system, the transmission network operator, to ensure the overall operation of the system according to quality of service standards.

- The **network service companies** may assume a more relevant role in the smart grid. These may include aggregators that use the demand flexibility of end-users for demand-side actions such as peak shaving and offering of ancillary services.

- Smart grids can foster new business for **equipment and technology suppliers**, who sell their services to the actors intervening in electricity distribution, as well as manufacturers of equipment and appliances for end-users. New business opportunities also arise for **added-value service suppliers** (energy service companies) to consumers.

- The whole system interacts with the **financial system**, which finances investments in smart grids.

- Also this system interacts with the **scientific and technological system**, which supplies knowledge and qualified human resources for the operation of all actors, for innovation and decision support.

In the CATWOE analysis four perspectives have been identified and explored. These perspectives under which it is relevant to promote smart grids and the associate technological developments are:

a) The smart grids as an instrument to optimize resources - smart grids will provide an intelligent manner to optimize resources, namely generation and distribution capacity but also the potential "hidden" resource which is the more efficient use of electricity by consumers.

b) The smart grids as opportunity of development and business - smart grids constitute an opportunity for economic development, fostering the creation of new businesses thus promoting technological innovation.

c) The smart grids to foster environmentally friendly technologies - smart grids constitute an opportunity to promote environmentally friendly technologies and energy efficiency, namely concerning the higher integration of renewable sources in the energy mix.

d) The smart grids to empower consumers / micro-generators - smart grids constitute an opportunity to increase the power of consumers and micro-generators, promoting their intervention capacity.

For each one of these perspectives the CATWOE analysis enables to identify a set of elements to be taken into account for the definition of evaluation criteria in MCDA, as suggested by Neves et al. (2009). To illustrate this process, Table 2 presents the analysis carried out for the first perspective.

Table 2. CATWOE analysis for the perspective "The smart grids as an instrument to optimize resources"

Clients	**What are the benefits and the disadvantages and why are they important?**
System operator, Distributor	(+) Lower costs, better quality of service, better information/monitoring, management flexibility, lower technical risks (-) Cyber risks
Society	(+) Lower costs and losses, better quality of service (-) Lower privacy, lower equity
Actors	**What is a good/bad performance?**
System operator, Generator, Distributor	(+) Lower costs, higher resiliency and reliability (-) Collapse/network dysfunction, loss of sensitive information, loss of commitment
Consumer	(-) Fraud/crime, loss of commitment, lack of collaboration
Weltanschauung	**Objectives unveiled**
Smart grids contribute to avoid/mitigate inefficiencies	Efficient utilization of installed capacity More efficient market
Owner	**Why stop or change the activity?**
Government, Regulator	Social acceptance, lack of funding, unverified economic benefits
Environmental constraints	**Objectives unveiled**
Financial resources	Modernize the network
Present technological basis	Form qualified staff e develop R&D
Existing know-how	Technological diffusion
Existing potential	Security of supply

The SSM described above, together with literature reviews, led to the identification of a “cloud” comprising about a hundred items, each one reflecting an attribute or a concern that could be evaluated when assessing policies to foster technological innovations in the electricity sector. The semantic analysis of this “cloud” of items (“social acceptance”, “tax benefits”, “costs of metering”, “to modernize the grid”, etc.) took into account the context in which each one emerged. This analysis allowed forming clusters of interrelated concerns pertaining to the same high-level objective. This formation of clusters is an important support to identify objectives, as demonstrated by research in psychology about memory (Bond et al. 2010). By defining categories one enhances the ability to enrich the list of objectives by means of cue-dependent retrieval: categories act as stimuli to remember targets in memory associated with them.

The categories that were formed are associated with fundamental purposes for technological innovation in the electricity sector. They can be seen as the top of a functional value hierarchy (Parnell et al. 2013, Ch. 7), which are combinations of the functional hierarchies from systems engineering with value hierarchies of decision analysis. Following (Parnell et al. 2013, Ch. 7), the top-level, fundamental objectives are end-objectives (rather than means-objectives). They are stated using expressions that are familiar to the stakeholders (in this work, actors involved in the electricity system), and are expressions that combine a verb plus an object for a clearer reading.

5 RESULTS

The resulting hierarchy of objectives is not tailored to any specific stakeholder. When using such a hierarchy to evaluate alternatives, all stakeholders can recognize the relevance of the objectives without having to agree on which are the most relevant or important ones. The resulting list of fundamental objectives is described in the following paragraphs, using an arbitrary presentation order.

Objective 1 - To benefit the environment and human health. One of the most frequently cited issues when discussing technological innovation in the energy sector is to reduce dependence on fossil fuels and the progressive replacement of these fuels by renewable energy. This is, however, a means-objective, i.e. using less fossil fuels is not a value in itself. The replacement of fossil fuels with renewable primarily seeks a fundamental goal that is the mitigation of greenhouse gas emissions or, more broadly, it aims at not harming the environment. Since there was also mention of other impacts on wildlife and human health, it was decided to define this objective in a more comprehensive way. This objective brings together, among many others, elements such as the avoided emissions through energy efficiency and the incorporation of renewables in the generation mix, the development of electric mobility, the impact on health and human mortality and other species, the use of soil and the use of water.

Objective 2 - To increase the flexibility and capabilities of the electricity system’s technological infrastructure. Technological innovation in the energy sector, in particular with the development of smart grids, is seen as an opportunity to modernize an electricity system in need of renovation, as well as to provide the electricity system with technical capacity to improve and to make its operation more flexible (in terms of grid and load management). One can debate whether this is a means-objective or an ends-objective. Having an electricity system with a more modern and more capable infrastructure contributes to multiple purposes (lower costs, better quality of service, better environment, etc.). But the development of this capital can also be seen as a political objective in itself, given the set of elements associated with it and the impossibility of reflecting directly the impact of this objective on the multiple purposes that it can promote for the different stakeholders. This objective brings together, among many others, elements such as peak shaving, ability to adapt and react, network monitoring, management flexibility, permitting an increasing share of distributed generation based on intermittent sources, and reducing losses.

Objective 3 - To ensure security of supply. Another desideratum sought when modernizing the electrical system is to ensure that demand is satisfied with low risk of disruption, considering technical risks (reliability), and political risks (foreign dependency). Note that the objectives 2 and 3 could be joined together in a more comprehensive formulation. However, the different nature of the concern regarding the risk advises for making this aspect explicit, as is often done in multicriteria benefits-costs-risks assessment. This objective brings together elements such as energy self-sufficiency, cyber risk, and quality of service.

Objective 4 - To ensure openness, fairness, transparency and efficiency of the electricity markets. Technological innovation is also seen as an opportunity to transform the electricity markets, corresponding to the aims of the regulator, the most competitive companies and the consumers. This reflects the aim to achieve a more open, efficient and transparent market, which can benefit from healthy competition between energy and services suppliers, and at the same time ensuring equity between the different agents. This objective brings together, among others, elements such as access to energy services, access to networks, increased competition, and efficient use of installed capacity.

Objective 5 - To provide financial benefit to the agents involved. Financial benefit is a ubiquitous aspect to stimulate the involvement of economic agents. The purpose of providing financial benefit translates the need to make investment in technological innovation interesting for those involved, because without this interest they will hardly accept these innovations. The financial benefit to the agents comprises revenues (including gains from reducing fraud), costs (investment, operational, etc.), subsidies and taxes, and concerns about low bills to consumers (considering tariffs and energy efficiency).

Objective 6 - To provide economic and social benefit to the country. This objective is of concern mainly to political decision makers, but it may indirectly benefit all the agents. It reflects the perspective that technological development can contribute to benefit the country that promotes it. This objective brings together issues such as the contribution to the national economy and employment, the encouragement of new businesses based on added-value services, the training of human resources and technological leadership.

Objective 7 – To ensure feasibility and to encourage adoption of technological innovations. Even if technological innovation can potentially bring many benefits, they will be of no avail if innovation is not adopted by the target stakeholders. Natural, financial and technical barriers may exist that hinder or prevent the success of innovation projects. This objective includes all the social and operational factors which could constitute a barrier to innovation projects, including legislative barriers, initial investment requirements, privacy concerns, availability of qualified human resources, telecommunications quality and other support services, etc.

One may note that some of the elements contribute to different objectives, although under different perspectives. For example, end-use energy efficiency contributes to avoid emissions (considered in Objective 1) and lower costs to the consumer (Objective 5). Another option could have been to consider this concern as a new high-level objective, in order to emphasize the importance of this objective for national policy. Such an option, however, would require particular attention in order to avoid double counting of benefits on objectives 1 and 5.

The objectives listed above were then further developed by listing the most relevant sub-objectives for the stakeholders in the electricity sector. Fig. 3 presents this decomposition, identifying the stakeholders most interested in each sub-objective. Finally, the initial “cloud” of items was revisited to ensure no important aspect had been missed.

6 CONCLUDING REMARKS

In the context of the project "Policies and incentive actions for technological innovation in the electricity sector: analysis of international experience and proposals for Brazil", this work aimed to develop and structure a set of fundamental objectives to promote innovation. Literature reviews, technical visits, and the use of SSM generated a dispersed cloud of aspects initially listed as potential concerns and criteria for the evaluation, which was necessary to structure. The categorization of these issues allowed us to propose a list of seven key objectives in line with priorities for technological innovation in the energy sector. This bottom-up approach was followed by a top-down approach aimed at breaking down each objective into sub-objectives clarifying the issues at stake under each perspective.

The work performed so far is an essential basis for the construction stage of the evaluation model, which will consist of the implementation of performance indicators for each objective and the definition of aggregation mechanisms to derive synthetic recommendations.

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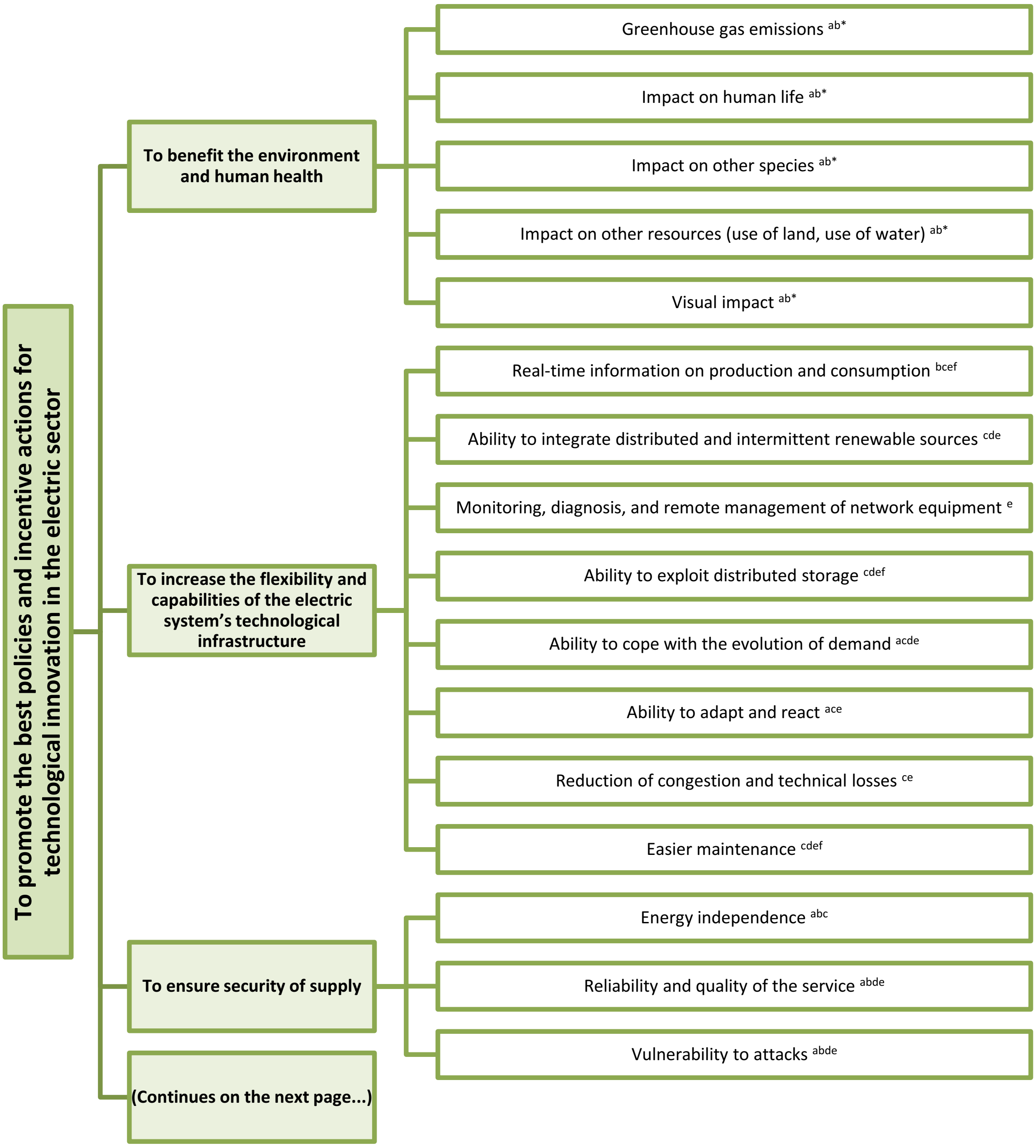

Figure 3. Objectives hierarchy identifying the interested stakeholder groups: a) Government and regulator, b) Consumers and civil society , c) Distributor / energy supplier, d) Power producer, e) system operator, f) Equipment and/or services suppliers, g) scientific and technological system, h) financial system *) also relevant to other stakeholders.

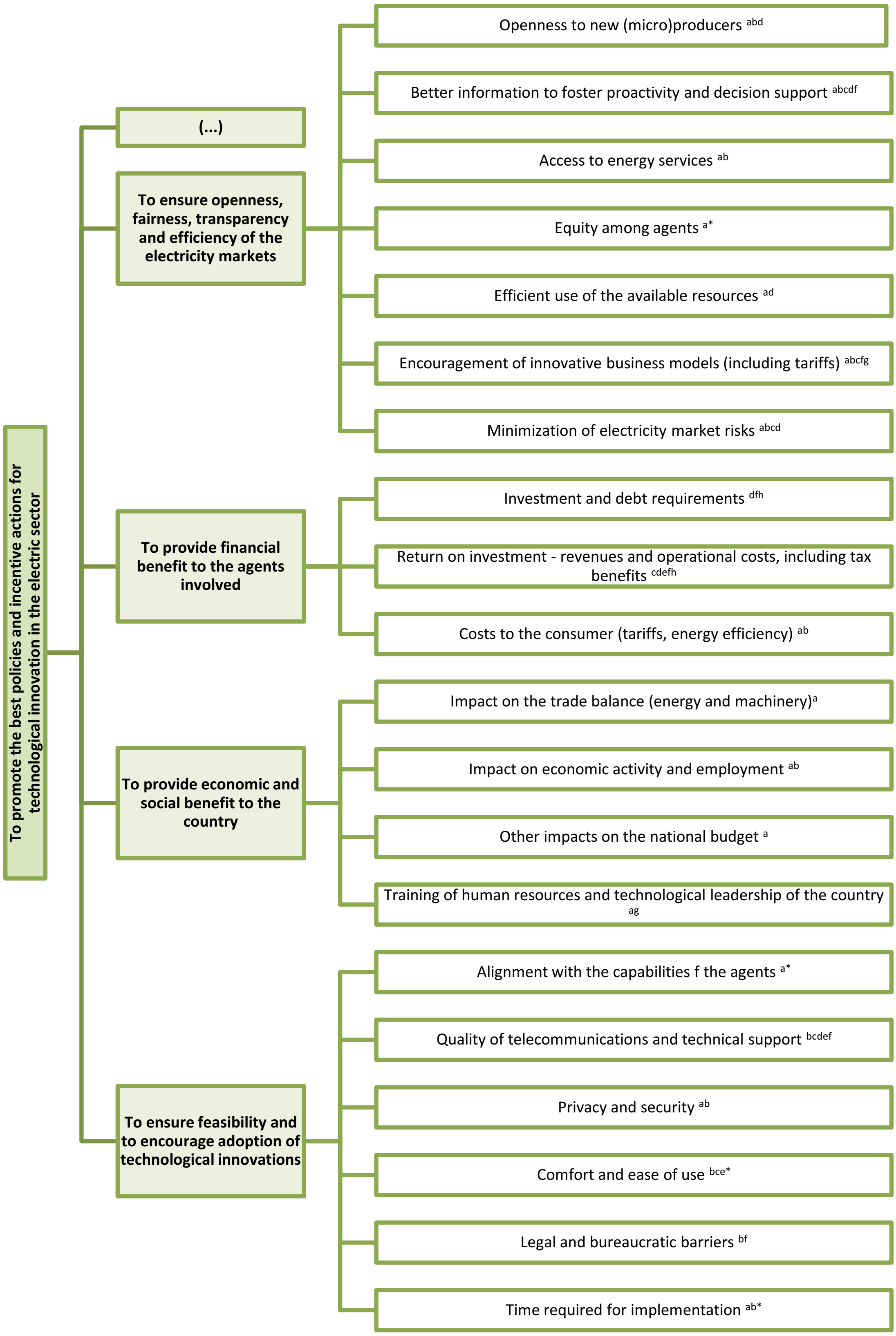

Figure 3 (cont.). Objectives hierarchy identifying the interested stakeholder groups.

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Brazil –Economic Regulation of Energy Transmission: Incentives for Innovation

Rogério Pereira de Camargo[1], Nivalde de Castro [2], Roberto Brandão[3], Maurício Moszkowicz[4]

[1] Rogério Pereira de Camargo, GESEL – Institute of Economy - UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, rogerio.camargo@gesel.ie.ufrj.br
[2] Nivalde de Castro, GESEL – Institute of Economy - UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, nivalde.castro@gmail.com
[3] Roberto Brandão, GESEL – Institute of Economy - UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, robertobrandao@gmail.com
[4] Maurício Moszkowicz, GESEL – Institute of Economy - UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, mauricio.m@gesel.ie.ufrj.br

ABSTRACT

The transmission network is the first link between large power generation facilities and electricity customers. It supplies energy at high voltages to substations, where the energy is distributed via the distribution network. The transmission network today operates with a high level of reliability, but presently a variety of technologies offers the possibility of great improvement in system performance.

Sophisticated new monitoring systems may reduce the likelihood of system failures and disruptions that cause serious economic and social consequences. Emerging efficient technologies may also help to solve network expansion constraints, including difficulties to install new transmission lines and to incorporate growing participation of intermittent energy plants, like wind and solar.

This paper starts presenting the status and perspectives of the Brazilian transmission sector showing the high level of investment planned until 2024 – 60% cumulative growth of line extensions and the same 60% rate for transformation capacity.

In the second part the paper presents the emerging technologies and the potential opportunities it offer to increase, among other factors, the energy quality, O&M structure, availability and reduction of technical losses. These advantages impact not only for new assets but also for the existing ones.

Considering the existing assets the paper starts a discussion about the regulatory framework ant the right economic signals to promote investment in innovation and automation. The paper then addresses the emerging regulatory of OFGEM in UK and the existing regulatory barriers that still exists internationally and in Brazil.

The paper concludes by identifying an opportunity for developing a regulatory R&D project to deeply analyze this subject and to propose a new regulatory framework to promote an economical feasible innovation process for the Brazilian transmission sector. In the last part the paper presents the guidelines and structure of the project GESEL is starting to develop in the scope of the Brazilian ANEEL regulated R&D program.

KEYWORDS: Regulation, Electric Power System, Transmission, Technological Innovation, Brazilian Electric Sector.

1. Introduction

The purpose of this paper is to discuss the regulatory complexity of the energy transmission sector process of innovation, considering that the Brazilian Electric Sector has a continental dimension with predominance of hydroelectric power plants that are getting more and more distant from load centers and also considering also the growing participation of intermittent energy resources.

Section 2 of the paper presents the current transmission sector structure and the planned future highlighting the great increase in transmission lines and the number of substations with estimated investment.

Section 3 presents of the emerging technologies highlighting the present status of the transmission sector worldwide, showing some of the specific technical problems of the transmission sector in Brazil.

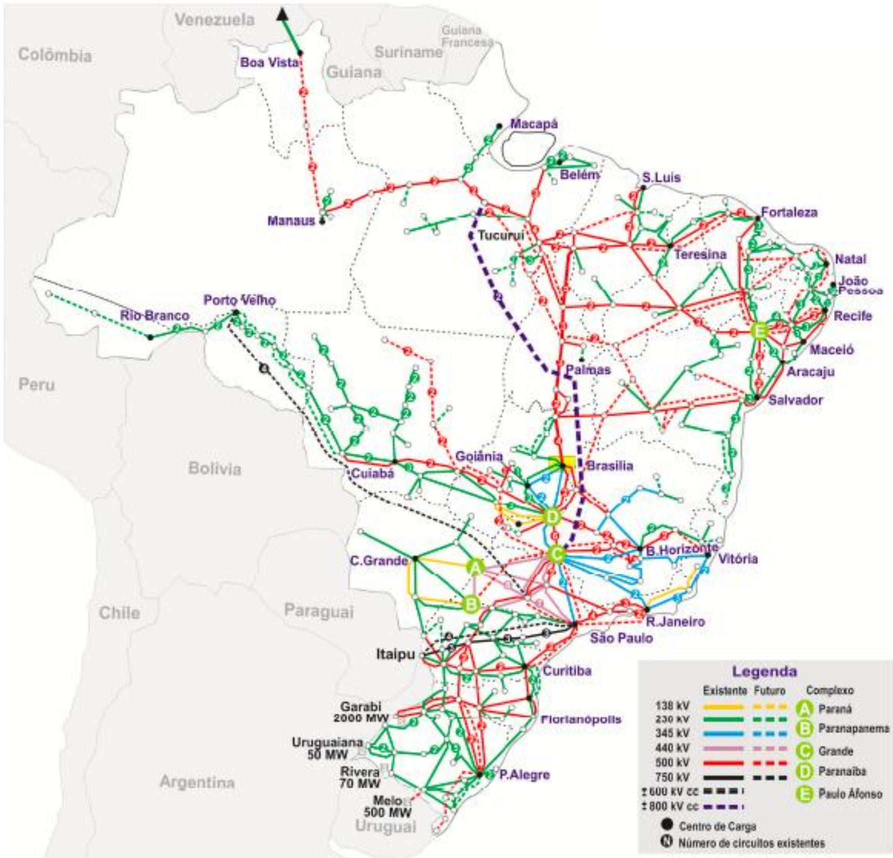
Section 4 presents the regulatory scenario of the transmission sector in Brazil and opens the discussion of how to develop a regulatory framework to motivate investors to introduce new technologies providing an economic signal for investors without creating impacts to the energy consumers.

The OFGEM regulatory framework based in the RIIO model for setting price controls for network companies is presented. It highlights the next decade challenge for the transmission companies for securing significant investment to maintain a reliable and secure network, dealing with the changes in demand and generation that will occur in a low carbon future.

In Section 5 of the paper introduces the Electric Sector Study Group (GESEL) of the Economy Institute of the Rio de Janeiro University R&D regulatory project in the aim of analyzing and discussing a new regulatory framework to push innovation for the Brazilian transmission sector.

2. The Expansion Forecast of the Brazilian Transmission Network

The Basic Brazilian Transmission System is composed of voltage lines in the range of 230kV up to 750kV. Figure 1 presents the topology of the Brazilian transmission network, highlighting the existing and projected lines.



Source: ONS

Figure 1 – Topology of the Brazilian Transmission System

The Ten-Year Energy Plan (PDE 2024), developed by the Brazilian Energy Planning Company (EPE), considered beside of the normal assumptions (mainly to increase the transmission network availability and operability) the following inputs to the transmission expansion forecast:

- Large Hydro Power Plants located in the North Region: mainly the power plants of the Tapajós River, Belo Monte and Teles Pires;
- Integration of 558 renewable energy projects, mainly wind farms, with an installed capacity of 14.000 MW. The great majority of the power plants are located in the Northeast and South region of Brazil;

- Integration of the Brazilian subsystems to take advantage of energy complementarities between the Brazilian regions;
- Integration of isolated electrical regions in the North area of the country;
- International integration with Uruguay, Argentina and Venezuela;

Tables 1 and 2 present the consolidated expansion values of the PDE 2024. Table 1 presents the extension expansion for each voltage level, and table 2 the increasing of MVA transformation capacity for each voltage level.

Table 1 – Line extension (km) forecasted in the PDE 2024

Tensão	±800 kV	750 kV	±600 kV	500 kV	440 kV	345 kV	230 kV	TOTAL
	km							
Existente em 2014*		2.683	6408	40.656	6.728	10.303	52.647	**119.426**
Evolução 2015-2024	10.055			42.783	353	1.666	20.870	**75.728**
Evolução 2015-2019	2.140			25.755	196	885	9.352	**38.328**
Evolução 2020-2024	7.915			17.028	157	782	11.518	**37.400**
Estimativa 2024	10.055	2.683	6.408	83.440	7.081	11.969	7.3518	**195.154**

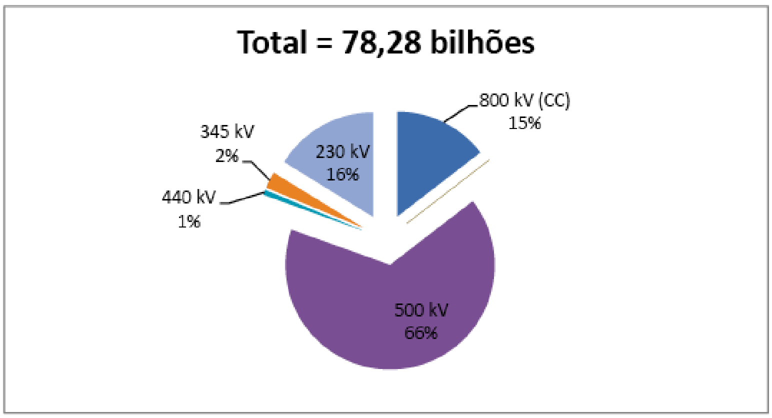
Nota: * Dados do DMSE/MME
Fonte: EPE

Table 2 – Transformation capacity (MVA) forecasted in the PDE 2024

Tensão	750kV	500kV	440kV	345kV	230kV	TOTAL
	MVA					
Existente em 2014**	23.247	129.095	23.916	49.795	79.565	**305.618**
Evolução 2015-2024	3.650	105.425	11.031	21.147	46.906	**188.158**
Evolução 2015-2019	3.650	58.339	5.081	14.747	24.933	**106.750**
Evolução 2020-2024		47.086	5.950	6.400	21.973	**81.409**
Estimativa 2024	26.897	234.520	34.947	70.942	126.471	**493.776**

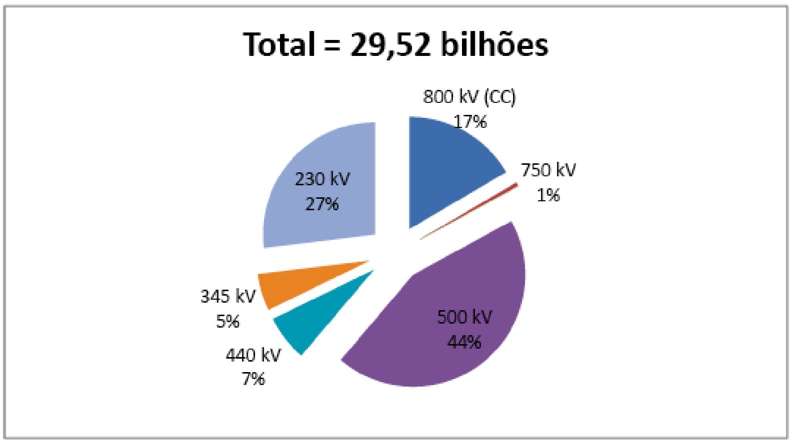
Notas: * Inclui os transformadores de fronteira.
** Dados do DMSE/MME
Fonte: EPE

Figures 2 and 3 present the forecasted investments in transmission line and substation construction.



Fonte: EPE

Figure 2 – Forecasted investment in transmission line construction



Fonte: EPE

Figure 3 – Forecasted investment in substation construction

The total estimated investment to support this expansion is of 107.8 billion Reais (approximately 25 to 30 Billions Dollars). The data presented forecast a growth of 60% in the overall line extension and transformation capacity.

The transmission expansion complexity arises from:

- The need to reconcile conflicting requirements of initial capital investment reduction (mainly because of the auction procedure) and system reliability. Conciliation of these two factors normally involves technological options (AC or DC, for example) and the need for alternative routes to the transmission lines to minimize the risk of multiple contingencies;
- The environmental constraints that limit the availability of line corridors and local provision for substations in the Amazon region and in major consumer centers (Southeast Region);
- The large number of transmission companies, with diverse backgrounds and different business characteristics, requires permanent coordination effort by the regulatory agencies, from the design phase until system operation. Due to this fact, the Grid Procedures developed by the Brazilian Independent System Operator (ONS), have to be heavily detailed and subjected to constant revision.

3. Improvements in the existing Transmission System

At a global level, the existing transmission system is being continuously challenged to anticipate and prevent blackouts or unexpected shutdowns, increase the transmission capacity, improve its availability and quality, reduce maintenance time, improve controllability, restoration and operability, implement mechanisms for load management, reduce losses and increase the ability to interconnect an increasing amount of intermittent generation (mainly wind energy) with high levels of reactive power.

Some Brazilian characteristics increase complexity:

- The tropical climate constraints imposed to the transmission assets (high temperatures, high humidity and high level lightning activity);
- The variability of high energy blocks flow during the year, stressing the regional interconnections;
- The highly concentrated consumption of energy in the southeast region while the new generation assets are mainly located in the North and Northeast areas;
- The economic and financial feasibility of introducing innovation in the already existing transmission system due to the Brazilian regulation framework.

3.1 Technological Innovation and System Reliability

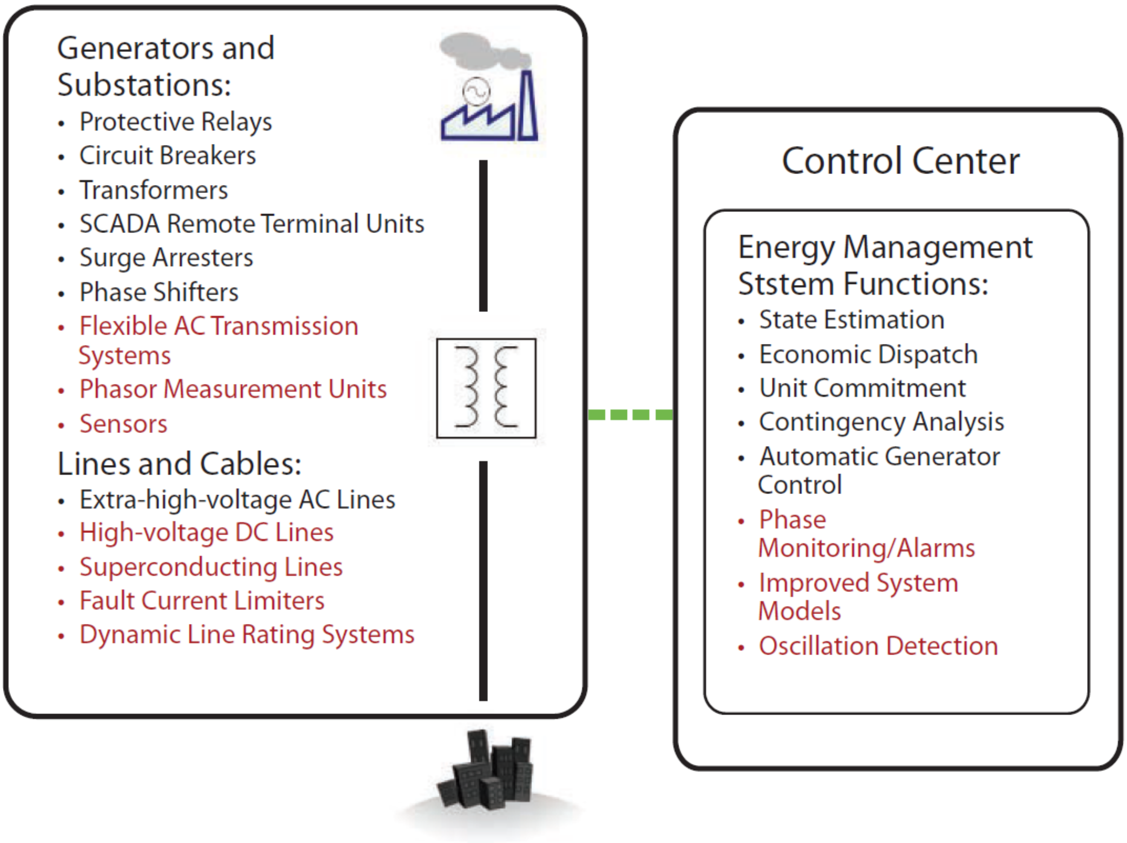
One of the technologies being studied and applied with greater emphasis focused on improving the quality of systemic operation worldwide is the PMU (Phase Monitoring Units).

Preventing or anticipating and reducing the magnitude of blackouts undergo a systemic view of the transmission network. In this regard has been increasingly applied the so-called WAMS (Wide Area Measurement Systems) which are collected from notable points of network data with high sampling rates, through PMU (Phase Measurement Units). These data are transmitted to the control center where they are processed in order to identify abnormal network conditions. The implementation of a WAMS System is normally regarded as a systemic initiative to be conducted by the System Operator (ONS).

To increase the capacity of the lines mainly three types of constraints has to be considered: thermal, voltage stability and transient stability. In Brazil with the increasing distances between power plants and the major load centers, new transmission technologies in extra high voltage and direct current (HVDC) have been studied and used. The emphasis on this subject is to implement or to increase the monitoring, actuation, automation and control algorithms and applications associated with the existing assets. The transmission company that owns the assets normally conducts this type of activity.

With the increase use of long lines, the need for reactive power compensation by means of series capacitors and static compensators so-called FACTS devices. These devices having a more elaborate technology makes the operation and maintenance more complex and determines the need to develop knowledge and technical training to deal with this new reality. The transmission company that owns the assets normally conducts this type of activity.

Figure 4 shows different technologies that can be used to upgrade the transmission network.



Note: Existing technologies and functions are listed in black; new and emerging elements are shown in red.
SCADA = Supervisory control and data acquisition.

Figure 4 – Technologies to improve the transmission network

The increasing degree of automation and technological innovations in the transmission system associated with investment in research and development are key elements to increase the overall quality of the transmission system.

3.1.1 Highlighting to the PMU (Phasor Measurement Unit) technology

WAMS consists of measurement devices, communications networks, and visualization software; the most critical is an enabling technology called the phasor measurement unit (PMU). The key issue of the PMU is that the measurement is taken at a very high sampling rate and that the time tag is associated with each measurement. This provides for asynchronous transmission of the information from the different locations and enables the correlation of data between these locations.

The PMU technology - **P**hasor **M**easurement **U**nit presents several advantages, such as:

Table 3 - Advantages of Technology - PMU - Phasor Measurement Unit
Improves the models simulating the behavior of major interconnections and power plants.
Simulates the transmission system behavior with mathematical models that predict how a power plant and transmission assets will operate under various normal and abnormal conditions.
Supports operators to supervise and coordinate the active reliably knowing operating limits and analyzing in real time, thus avoiding errors and blackouts.
Supports software applications to aggregate and to analyze the PMU data and produce actionable information for system operation or planning are critical to realizing the full benefits of PMUs.
Measures defining characteristics of voltages and currents at key substations, generators, and load centers, such as cities.
Supports state estimation algorithms with the use available measurements, such as the magnitudes of system voltages and currents, to estimate the system state. The system operator uses the state information to optimize power system operation. System optimization includes contingencies and corrective actions. State estimation algorithms read system measurements to determine the state of the system within a predetermined error. Traditional system state estimation takes around 10 minutes. Synchronized phasor measurement takes approximately 100 msec to calculate the system state, 6,000 times faster than the traditional approach.

Source: Tab. 01 - US Department of Energy – August 2014 – Smart Grid System Report to Congress

The Phasor Measurement and Control Units (PMCUs) located at different parts of the power system make synchronized phasor measurements that provide a "snapshot" of the power system using absolute time reference. For example, we can obtain voltage phasor information across the power system to determine the power system operating state.

4. Regulatory innovation to encourage the use of new Technologies

As previously presented there is a strategic importance to give the economic signals to push innovation in the existing transmission system. This type of discussion is being held internationally. The key question is: How economic regulation can provide adequate and consistent economic signals for agents to invest in automation and technological innovations in countries that adopt liberalized models with emphasis on low tariffs?

Solving this issue is important to convey the desirable investments from a social point of view with the investor economic perspective. Some authors and regulatory agencies such as the UK OFGEM, show that the traditional tariff regulation can send an imperfect economic signal for transmission agents with negative effects on the quality and safety of the electrical system.

One important effort to overcome this problem is being developed in the UK OFGEM (Office of Gas and Electricity Markets) that is developing a new regulatory framework focusing what they termed RIIO (Revenue = Incentives + Innovation + Outputs- Products). The starting point is the recognition that over the next decade the transmission companies will face an unprecedented challenge of securing significant investment to maintain a reliable and secure network, and dealing with the changes in demand and generation that will occur due to a low carbon future.

The goal is to ensure that the energy is delivered at a fair price for consumers. RIIO is designed to encourage network companies to:

- Put stakeholders at the heart of their decision-making process;
- Invest efficiently to ensure continued safe and reliable services;
- Innovate to reduce network costs for current and future consumers;
- Play a full role in delivering a low carbon economy and wider environmental objectives.

Investments focused on increasing the level of automation of the transmission network and / or introduction of technological innovations may involve:

- The replacement of not yet depreciated assets presenting low technical performance;
- The installation of new equipment not envisioned in the original design;
- The reduction in operating costs due to higher degree of automation; and
- The application and software development that can provide greater reliability to the system.

In order to evaluate the impacts of the innovation process we must consider some components of the problem:

- Capital Investment: considering a transmission company with regulated tariff, as several Brazilian transmission companies that renewed the concession agreements in 2013, the replacement of equipment not yet fully depreciated poses a reduction in the remuneration regulatory base and therefore a reduction in the tariff associated to the previous investment. Of course, the new investment will be recognized for tariff purposes, but the net effect in terms of increase will be reduced to the extent that the asset decommissioned leaves the remuneration equation. This situation gives a negative economic signal to invest in innovation even if it brings advantage for the transmission system.
- Operational Costs: Regulatory agencies resist compensating investments related to process improvements that result in cost reductions. The basic issue is: Does it make sense to include the remuneration base - and therefore pay – for investment that will result in reduction in operating costs and thus increase the profit potential? The answer to this question is complex but without solving it, the result is a negative economic signal to investment in transmission efficiency. Additionally even if the company decides to invest there is a risk that the improvements do not pay back in a single tariff cycle, and the operational benefit be captured by the consumers in the next cycle.

The Brazilian regulatory framework has started to address those issues in the auctions for new transmission networks. It was created a mixed regime where most of the concession revenue is set during the auction for the construction and operation of a new transmission installation, but part of the revenue of the regulated tariff will be pay for expansions and upgrades authorized by the regulatory agency (ANEEL).

5. GESEL R&D Regulatory Project

In order to address consistently the above-related topics, the Electric Sector Study Group (GESEL) of the Economy Institute of the Rio de Janeiro University started a regulatory research and development project to be developed in the framework of the regulatory agency (ANEEL) R&D program. Figure 5 presents the basic structure of this project.

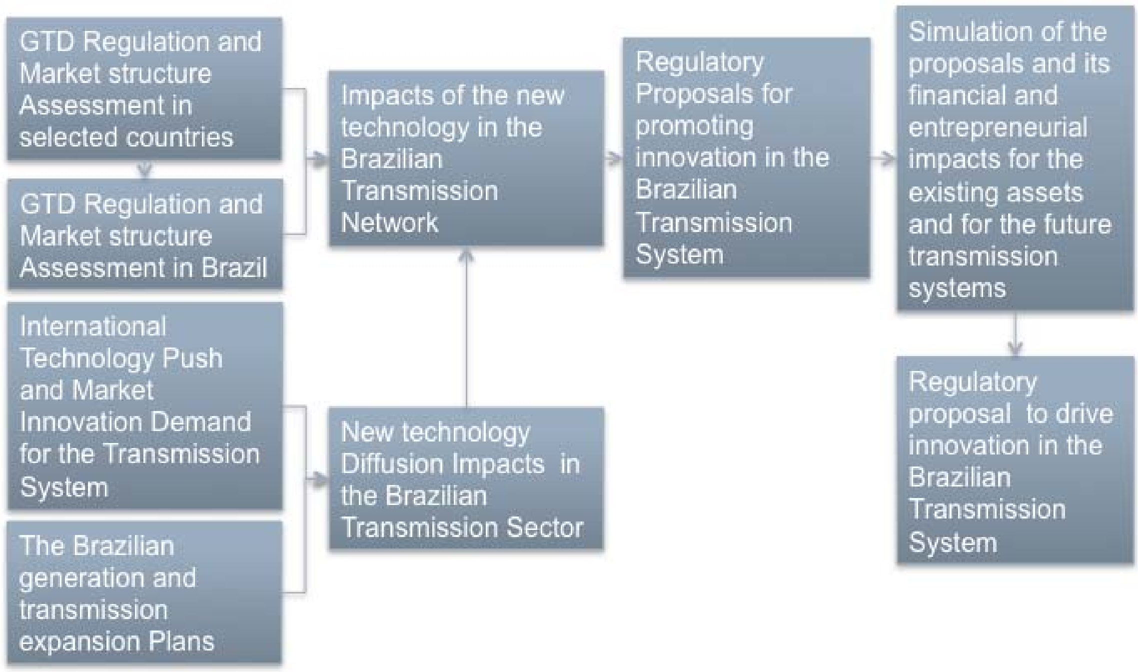


Figure 5 – Basic Structure of GESEL Regulatory R&D Project

The project was divided in six phases:

I. Assessment and comparison of international and national regulation for promoting innovation in the transmission sector;
II. International technology push and market innovation demand in the transmission sector and opportunities and impacts in the Brazilian transmission sector;
III. Developments of scenarios for technology innovation and diffusion in the Brazilian transmission sector;

IV. Based on the developed scenarios, propose regulatory innovations to promote innovations;
V. Simulation of the qualitative and quantitative impacts of the proposed regulations considering the expansion plan;
VI. Discussion of the proposed regulation with the main stakeholders (regulators, electric companies, association, government institution).

6. Conclusions

The profound technological evolution of the electricity sector is strongly linked to the dynamics of innovation.

Simultaneously, it is recognized that all the innovation process is conditioned by the transmission sector economical regulation in order to present clear indications to promote public and private investments. The main guideline is to consider elements of economic theory and trends of the technological diffusion to conceive the appropriate conceptual framework for balancing investment; the quality of energy and the cost the society is willing to pay for the energy.

In the Brazilian transmission regulation model, it can be identified some conflicts that can delay the adoption of technological innovation: one major example is the commitment to achieve the lowest tariffs that may conflict with the implementation of technological innovations during the life cycle of the projects.

GESEL is committed to develop a deep analysis of the subject considering the ongoing evolution of the worldwide regulatory framework and the Brazilian sectorial condition in order to make regulatory proposition and to promote discussions. The goal is to conceive what could be a regulatory framework to promote innovation on the Brazilian transmission sector without impacting the energy consumers.

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Brazil and the international electric integration: Background, Current Status and Perspectives.

Nivalde de Castro[1], Roberto Brandão[2], Rubens Rosental[3], Paola Dorado[4]

[1]*GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil.* *nivalde.castro@gmail.com*
[2]*GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil.* *robertobrandao@gmail.com*
[3]*GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil.* *rubens.rosental@gmail.com*
[4]*GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil.* *paoladoradogoitia86@gmail.com*

ABSTRACT

Electric integration is a topic discussed and promoted worldwide due to the advantages for the countries involved. In order to enjoy these advantages several countries, mainly in Europe, have created regional electricity markets. For South America countries the creation of a regional electricity market is still a distant option due to economic and social asymmetries and, especially, because of incompatibilities in the regulatory framework and in energy trading mechanisms.

This paper aims to analyze the electrical integration process in the South America, concentrating in Brazil the central focus of the analysis. The main constraints of Brazil's regulatory and electricity trading model are also analyzed, highlighting that the last restructuring process of the electric sector (2003-2004) has defined a commercial model where financial contracts of "physical guarantee" are traded and not electricity itself, and where the power plants do not have autonomy over their production. The characteristics and specificities of the Brazilian model determine boundaries and conditions that must be considered to enable international electricity trade.

The already existing integration projects are also analyzed highlighting that these projects were developed under special conditions for taking advantage of specific opportunities without the support of a strategic integration policy. Additionally, the paper addresses two other electrical integration projects that are under discussion, the binational hydroelectric power plants between Brazil-Argentina and between Brazil-Bolivia.

The paper concludes that electrical integration with direct participation of Brazil is more feasible for binational projects and short-term surplus trade because of the differences between the Brazilian market design and the other countries market design.

KEY WORDS: Electric international integration, Brazil, energy commercialization.

1 INTRODUCTION

Regional Electric Integration is a topic broadly discussed and incentivized worldwide, due to the advantages for the countries involved. Among them are: the more efficient use of energy resources for electricity generation, reduction of the wholesale prices and, specially, the reduction of its volatility, the incentive for efficiency generated by increasing the market competition, and more reliability and security for providing this service.

In order to take advantage of these benefits, many countries, especially in Europe, created Regional Electric Markets (REM) in which market competition exists for buying and selling electric energy. However, in South America the constitution of a REM, following the European model, is yet a distant option because of the existing economic and social asymmetries between the countries and, mainly, because of the adoption of different commercialization rules in each country. These factors greatly delay the electric integration process on the region.

Despite of these difficulties, Brazil has interconnections with Paraguay (Itaipu Binacional), Argentina (frequency converters in Garabi), Uruguay (frequency converter in Rivera) and Venezuela (transmission line between Roraima and Guri). These projects were developed under particular solutions for taking advantage of specific opportunities, without the support of a strategic integration policy of Brazil with the other countries.

Additionally, some electric integration projects are in the discussion agenda. Among them are:

- The construction of a new frequency converter and a transmission line to enhance the energy trade capacity between Uruguay and Brazil;
- Two binacional hydroelectric plants, Garabi and Panambi, on the Uruguay River on the border of Brazil and Argentina: these projects are at the engineering and environmental studies phase;
- A binacional hydroelectric plant with Bolivia on the Madera River: this project still at preliminary state of discussion;
- A hydroelectric plants in Peru for supplying the domestic market and selling the surplus to Brazil;
- The construction of hydroelectric plants in Guiana and in Bolivia for exporting part of the generated energy to Brazil, these projects still in preliminary state of discussion.

This paper aims to understand and analyze the electrical integration process in the South American region, positioning Brazil in the central focus of the analysis. It is divided in four sections besides this introduction. The first section examines the main electric matrix characteristics and the Brazilian potential for electric generation using just local resources. The second section analyses the Brazilian commercial model pointing out the restrictions to a full electric market integration. The third section describes the Brazilian electric integration experiences and discusses the possibilities for importing and exporting energy in the current context. Finally, the conclusions, which considers that the electrical integration with direct participation of Brazil is more feasible for binational projects and short-term surpluses exchanges due to the differences between the Brazilian business model and other South American country models.

2 THE BRAZILIAN ELECTRIC SYSTEM

The objective of this section is to present the main characteristics of the Brazilian electric sector. The electric matrix is presented as well as the expansion forecasts. Considering these elements is a key condition for analyzing the electric integration possibilities of Brazil with the other South American countries.

2.1 The Brazilian electric matrix

The Brazilian Electric System (SEB for its acronyms in Portuguese) had an installed capacity of 139,8 GW in 2014 (MME, 2015). The National Interconnected System[1] (SIN for its acronyms in Portuguese) has an installed capacity of 128,4 GW[2] in the same year, as shown in Table 1. The difference of the SEB and SIN installed capacity are systems installed in isolated areas mainly in the North Brazilian Region (Rain Forest).

Table 1: Installed Capacity for Generation in Brazil by source, 2014

(% of the Total and GW)

Source	SIN	Isolated System	Self production	Total Brazil
Hydro	73,1	21,7	8,8	68,0
Thermal	21,5	78,3	91,2	27,1
Nuclear	1,5		0,02	1,4
Wind	3,8		0,04	3,5
Solar	0,01			0,01
Total (GW)	**128,4**	**1,3**	**10,1**	**139,8**

Source: Ministry of Mines and Energy (MME) (2015, p.10)

[1] SIN interconnects all major consumption centers, as well as the basins where are installed the main hydroelectric plants.

[2] The remaining installed capacity is divided by: isolated systems 1,3 GW and 10,1 GW corresponds to private installations for self production, especially industries.. .

In 2014, the total energy generated in the SEB was 624,2 TWh and 566,7 TWh were consumed in the SIN (MME, 2015). Analyzing by source of generation is showed the predominance of hydroelectric generation for supplying the SIN, even considering the ongoing modification of the Brazilian electric matrix and the hydrological drought cycle that started in 2012. According to Table 2, in 2014, 71% of all energy used in the SIN came from hydroelectric power plants, meanwhile the thermal generation plants were responsible for 24,1% of the energy supplied to the SIN. This is an evidence of the increasing importance of the thermal generation in the Brazilian electric matrix.

It is still worth to consider the importance of wind energy, in 2014 this source supplied 2,2% of the SIN while the nuclear generation represented 2,7% of the SIN energy.

Table 2: Energy Generation by source, 2014

(% of Total and TWh)

Source	SIN	Isolated System	Self production	Total Brazil
Hydro	71,0	27,5	6,5	65,2
National	65,2	11,6	6,5	59,8
Imported	5,8	15,9	-	5,4
Thermal	24,1	72,5	93,5	30,3
Fossil fuel	20,1	71,8	49,1	22,9
Renewable	4,1	0,7	44,3	7,4
Nuclear	2,7	-	-	2,5
Wind	2,2	-	-	2,0
Solar	0,002	-	0,010	0,003
Total	100,0	100,0	100,0	100,0
Total (TWh)	**566,7**	**5,3**	**52,2**	**624,2**

Source: Ministry of Mines and Energy (MME) (2015, p.7)

In normal hydrology, the dispatch of the SIN usually met the demand mainly with hydroelectric plants. The difference was supplied by null variable costs plants (co-generation and wind) and power plants that has contract obligation for minimum generation (inflexibility), like the two nuclear plants (Angra I and Angra II) and thermoelectric plant with take or pay fuel contracts. Most of the time the thermal power plants were used as system backup.

However, as shown in Table 3, since 2012 the thermal generation is becoming more representative, partly due to contextual factors and partly due to structural factors.

The contextual factors refer to the hydrologic crises that Brazil is facing since 2012, which led the National Independent System Operator (ONS for its acronyms in Portuguese) to dispatch thermal plants for long periods. Since that time, the dispatch time of thermal power plants was greater than the original expected time, stated in the auction statements. For instance, between 2012 and 2014, the dispatch time of a thermal plants contracted in the 2007 auction was greater than the overall fifteen years of estimated operational time stated in the original project contract. This operational stress imposed several technical and maintenance problems (CASTRO *et all*, 2014).

The structural factors are related to the electric matrix change, due to the difficulties to obtain environmental license for the construction of new hydro power plants and because new hydro projects are *run of the river* plants with small dams that has storage capacity for just few days. The *run of the river* hydro power plants are more environmental friendly, but they also reduce the regulating capacity throughout the year because it reduces the reservoir size. This lower ability to regulate the system determines the need of complementary sources, mainly for supplying the energy demand during the dry season (CASTRO et all, 2012). In this context, the Brazilian electric matrix needs complementary sources with a greater participation of other sources in the annual energy generation, among these sources are the thermoelectric plants that uses fossil fuel, as shown in Table 3.

Table 3: Energy generation dispatched or programmed by ONS for the SIN: 2005-2014

(% of total)

Year	Hydroelectric	Thermoelectric
2005	92,4	5,1
2006	91,8	4,8
2007	92,8	4,3
2008	88,6	8,1
2009	93,3	3,7
2010	88,8	7,9
2011	91,2	5,3
2012	85,9	10,4
2013	78,7	17,2
2014	73,0	23,0

Source: ONS (2015,a)

The Brazilian transmission system has more than 100 thousand Km of high tension lines and was originally constructed to allow the optimization of hydropower generation, through the exchange of large blocks of energy over long distances. The complementary optimization hydro resources effect is one of the reasons Brazil has only one system operator.

As *the run of the river* hydropower plants are inserted in the generation capacity and considering the demand increase, the ONS will have to operate the existing dams promoting a greater variation on the dams water level in short periods of time (CASTRO et all, 2012) and, consequently, there will be greater need for complementary sources to hydroelectric plants.

2.2 **Energetic potential and perspectives for the electric matrix.**

The official planning agency named Energy Research Company (EPE-for its acronyms in Portuguese)forecasts a significant increase in consumption during the coming years[3], this demand will be supplied exclusively using domestic generation plants. Although there is a wide diversity and quantity of natural energy resources to be used in reasonable scale and with economic feasibility, Brazil will need to import fossil fuels for thermal power generation, particularly in the form of liquefied natural gas (LNG).

The expectation of the Ten Year Plan for Energy Expansion (PDE 2023), prepared by EPE, considered firstly the 30.043 MW (EPE , 2014; . p 80) projects already contracted in auctions entering in operation between 2014 and 2018. The additional energy to meet demand until 2023 (estimated at 41.044 MW[4]) would be supplied mostly with the construction of new hydroelectric power plants (14.679 MW), followed by thermoelectric plants (7.500 MW) and from alternative energy sources (wind, co-generation from biomass and small hydro plants),

The hydro potential is mainly concentrated in the Amazon biome and, therefore, the Brazilian energy frontier is expanding toward the Amazon, with the construction of large hydropower plants (CASTRO , 2007)[5]. It is estimated that by 2023 the northern part of the country will have a expansion of generation capacity of 30.504 MW over the existing 14.506 MW in 2013 (EPE, 2014; p.78). Most of this expansion will take place with *run of the river* hydropower plants that will require complementary generation.

The PDE 2023 also predicts a major expansion of thermoelectric plants, 7.500 MW between 2019 and 2023. The expansion of thermal power generation depends mainly on the availability of fossil fuels, primarily the

3 According to EPE (2014 , p. 35) , the consumption of electricity in 2023 will be 780.4 TWh , 45% more than the consumption of 535.2 TWh recorded in 2014

4 According to the EPE (2014 , p. 78) until 2023 will be added 71.087 MW , of which 30.043MW should come in operation by 2018

5 The main hydropower plants under construction are: Santo Antônio (3.150 MW) and Jirau (3.750 MW), both located in Madera River and in final phase of motorization. Belo Monte (11.233 MW) and Teles Pires (1.820 MW) on the Xingu River. There are also projects at the environmental licensing phase, the largest of them is the Tapajós complex, with a capacity of over 11.000 MW. The hydroelectric potential in the Amazon basin is estimated in more than 100,000 MW, this magnitude determines the priority of the government's energy policy to maintain strong investments in hydropower in this region. This decision is subject to obtaining environmental licenses in periods consistent with the need in order to meet the growing demand.

availability of natural gas. The supply of natural gas in Brazil depends on three factors: domestic production, imports through the Bolivia-Brazil gas pipeline and the Liquefied Natural Gas (LNG) imports.

Although the national production that is expected to increase 170% until 2023, the Fig.1 shows that the supply of natural gas in Brazil will still depend on imported resources, both from Bolivia through the pipeline as well as LNG imports.

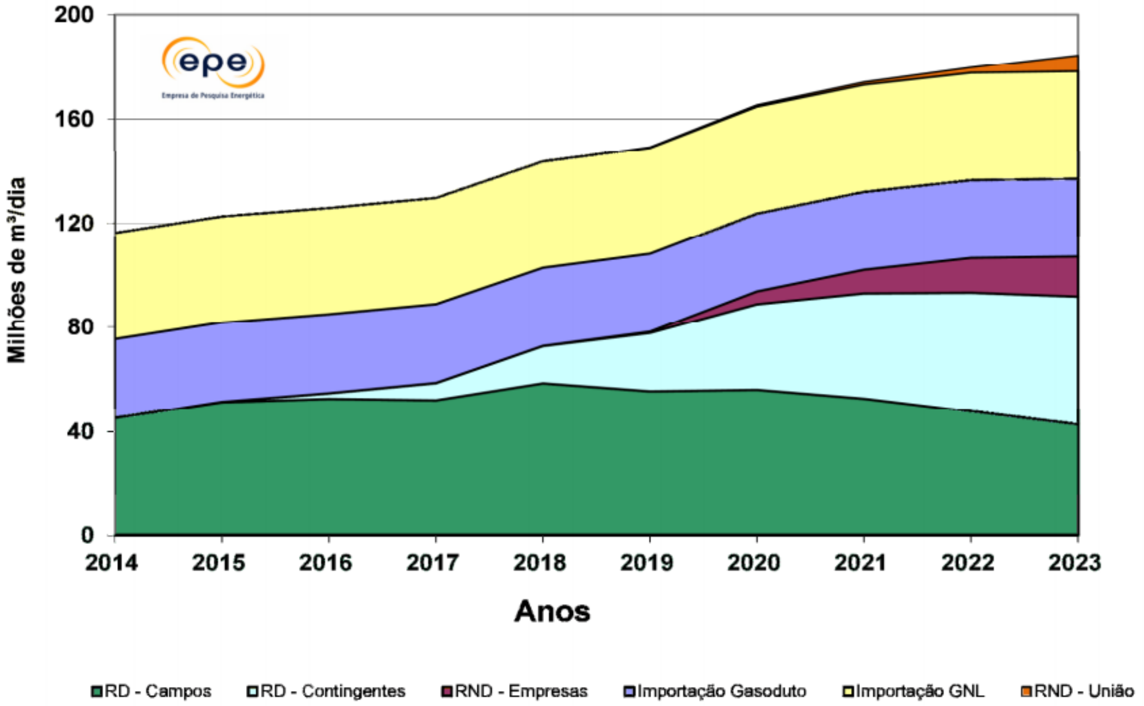

Figure 1: Natural gas supply for the integrated network in Brazil: 2014- 2023

EPE (2014, p. 293)

The increase in power generation using natural gas is not only a feasible alternative but is a must, considering the changes in the Brazilian electric matrix where thermal generation will have a key role. As an example of the importance of thermal sources, in the auction held in April 2015, to be available in 2020 (referred to as A- 5 Auction), a thermoelectric plant of 1.515MW which uses imported LNG[6], obtained a supply energy contract offering electricity with price of 70,63 USD/ MWh[7] (ANEEL, 2015,a)

In relation to other renewable sources, the EPE forecast an important increase of wind participation in the electric matrix. Since 2005, Brazil began to explore its great wind potential, estimated in 350GW (IEA, 2014,p.391), and the costs reduction has exceeded the most optimistic forecast. The wind projects have revealed the competitiveness of this source. Brazil auctions have already hired more than 7.000 MW of installed capacity of wind power to start its operation between 2016 and 2020 (ANEEL, 2015 a). Given the current price scenario and the existing wind potential in Brazil, the trend is that the hiring of wind project will remain intense in the coming years.

In addition to hydropower, thermal with natural gas and wind, Brazil also has another option with competitive costs. It is the co-generation using residual biomass from sugar cane. The technical potential for generating electricity using this source would allow to offer 7.7 GW until 2023, from which 1.4 GW will start its operations until 2018 (EPE, 2014; p. 90)

For solar energy, the installed capacity is still very small. However, there is a growing interest in developing the necessary conditions to the participation of this source in the Brazilian electrical matrix. In fact, on the auction

[6] The thermal power plant will be installed in Porto Sergipe with an estimated construction cost of R $ 3.2 billion. The project includes the construction of a regasification terminal for the operation of the thermoelectric (GENPOWER GROUP, 2015).

[7] Using the exchange rate of December 25, 2015 informed by Brazilian Central Bank, 3,95 R$ per US dollar.

held in October 2014, were contracted 889.6 MW of solar energy with an average price of 54,51 USD/ MWh[8] (ANEEL, 2015 a)

The PDE 2023 does not consider any increasing in the electricity importation. However, this position does not mean that international projects involving energy imports cannot be developed[9]. These projects may be incorporated into the planning but would be directly conditioned to negotiations that will allow the hiring of firm energy by the Brazilian market. Until now, there is not consistent study to enable medium and long-term import contracts in the current Brazilian regulatory environment.

3 THE BRAZILIAN BUSINESS MODEL

The Brazilian business model, unlike other countries in the region, does not allow the trading of physical energy. The trading of energy is through financial mechanisms that not necessarily involve physical delivery of energy from the generation company. The agents must buy or sell contracts representing a guarantee a "physical guarantee" and not energy itself. The logic behind this mechanism is that an individual generator does not have the responsibility to meet consumer demand, because it does not have the empowerment over its own generation unit. It is the responsibility of the Brazilian ISO (ONS) to dispatch all the generation assets in an optimal and centralized way[10].

This business model was designed to deal with the singularities of the Brazilian electric system, predominantly hydroelectric, in a business environment that, from the nineteen's, went through a liberalization process with the introduction of market mechanisms for energy trading.

The problem by that time refers to the short-term prices of energy in a system that produces electricity essentially with fixed costs, basically hydropower plants. It is easy to demonstrate that a price equal to zero can occur in industries where production is based on fixed costs and where the products are traded in a competitive market. Prices may be zero because: (i) in competitive markets price is always equals to the marginal cost of the least efficient producer; and (ii) the marginal cost of an industry that produces only based on fixed costs is zero. In this sense, if the Brazilian business model were based on a spot energy market, prices would be, for large periods, very low or even zero, becoming significant only in times of water shortages. If generator revenues were formed based on spot market prices they would not be enough to pay all the production costs for long periods, especially when hydrology were favorable.

During the 2001 and 2002 water shortage the above mentioned problem was intensifies and the business model was corrected with the reform of 2003 and 2004. The new business model ensures and encourages competitiveness for power generation. However, the competition focus is not in the physical power market, but in a market for financial contracts of "physical guarantees"[11]. The new dynamic for energy auctions makes the long-term contract prices to converge to the average cost of energy. Additionally, by offering long-term contracts with highly predictable revenues and indexed to inflation, the National Bank for Economic and Social Development (BNDES for its acronyms in Portuguese) offers long-term financing using project finance mechanisms for all the winning projects. The main guarantee of the financial contract is the future cash flow of the project based in the produced energy.

The "physical guarantee" that is the fundamental characteristic of the SEB. There are not energy contracts, but energy guaranty contracts. This way, each power plant, regardless of the source, receives from the Ministry of Mines and Energy (MME) certificates that can be traded with consumers through contracts. These certificates represent, using a specific rule, the entireness or a fraction of the energy that the power station could produce. The certificates are calculated by an official methodology that consists in modeling the optimized operation of the SIN, with all the projects already contracted and the new projects that want to participate in an auction. The aim of this model is, in a first step, to calculate the highest load that the system (critical load, or system physical

[8] Using the exchange rate of December 25, 2015 informed by Brazilian Central Bank, 3,95 R$ per US dollar.

[9] From the planning mechanics point of view, with a horizon of ten year will be easy to include a forecast for the energy importation in case of the projects move forward, because every year the EPE review the planning for the next ten years.

[10] The centralized and optimized management of water resources in a system with the scale and size like the Brazilian, reduces the dependence that hydropower has with respect to the local hydrology uncertainties and, therefore , makes it possible to meet a higher electric load compared to what would be possible with an uncoordinated system operation

[11] On the one hand, there is an obligation of the agents to have 100 % of it consumption backed by financial contracts of "physical guarantee". On the other hand, all the needs of the regulated market must be contracted in long-term contracts (30 years). Hiring energy for the regulated market is done through new energy auctions organized by the government on behalf of the distributors, thereby creating a monopsony buying structure.

guarantee) could meet given a safety criterion (5% deficit risk in any given year) and other conditions for an economic operation.

In a second step, the critical load of the system is divided between all the modeled production units. The share corresponding to each generator is their "physical guarantee”, which corresponds to the energy certificates that can be traded with consumers through contracts.

The business model has proven to be adequate for ensuring the correct operation of the Brazilian electric sector, it gives economic signals for capacity expansion at low costs using the auctions to expand the supply for the regulated market.

The entire model is based on the concept of "physical guarantee ", which is consistent when the generation units are represented as a closed system, operated in an optimal and centralized way. No other country in Latin America adopts a business model similar to the Brazilian one.

Given these technical and commercial characteristics, the Brazilian electrical integration with neighboring countries will not occur, using the same model as in Europe, which consists of a common energy market responsible for defining the generation of each plant, the energy prices and the energy exchanges. In fact, the Brazilian model does not makes sense if it is not possible to represent the generation resources and the energy demand in a closed system, optimized in a centralized form.

Although Brazil has abundant alternatives for generating electricity using domestic resources and has a model that allows to expand the supply minimizing the costs. Even considering the difficulties and limitations for implementing a truly integrated energy market in South America, the growing need of firm energy and the present shortage of national natural gas create opportunities for energy integration.

On the one hand, seasonality of water flows between the hydrological regimes in the Southeast / Midwest (where are localized the dams with greater water capacity) and the hydrological regime in the south and the Amazon region (EPE, 2014; p. 84) enhance the economic feasibility of binational projects with Bolivia[12] and Argentina[13]

On the other hand, the growing need for natural gas at competitive prices has created opportunities for importing LNG for supplying electric generation. In addition, some neighboring countries companies with gas availability[14] has showed interest in investing in the Brazilian electricity market by building fired power plants.

4 ELECTRIC INTEGRATION

In this section are analyzed the existing experiences of electrical integration between Brazil and its neighboring countries, also are pointed out some future electrical integration possibilities.

4.1 Integration Experiences of Brazil

There are a consistent technical and economical reasons that pushes the international integration of electrical systems. For example, the integration of different generation matrixes and different seasonal consumption profiles allows the optimization of available resources, offering benefits for all the parties involved. Even the simple shared use of sources can allow economy of scale. However, the technical benefits of electric integration are maximized only when it is possible to establish common and solid trade rules. The harmonization, or at least the compatibility, of regulatory and trade rules is the basic assumption for a joint optimization of electrical resources between countries.

Regarding Brazil´s position in the regional electrical integration process, as previously analyzed, has to be consider that the energy trading mechanisms were designed in a closed format, and also planed and operated in a centralized way. Therefore is not suitable for a full-integrated market scheme.

Even considering these structural constraints, Brazil developed special business model to import and export energy with Paraguay, Argentina, Uruguay and Venezuela.

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[12] On July 17, 2015 was signed the Addendum to the Memorandum of Understanding in the field of energy between the Ministry of Mines and Energy of the Federative Republic of Brazil and the Ministry of Hydrocarbons and Energy of Bolivia (signed on 17 December 2007) , which aims to facilitate the studies of financial viability, and technical and environmental studies for building a binational hydroelectric dam on the Madeira River Basin

[13] Since 2012, the company *Unión Transitória de Empresas*, obeying the request of Eletrobrás (Brazil) and Ebisa (Argentina), has been developing engineering and environmental studies as well as a social communication plan for the hydropower plants of Garabi and Panambi located on the Uruguay River in the binational stretch between Brazil and Argentina (ELETROBRAS, 2010).

[14] This is the case of the National Electric Energy Company of Bolivia (ENDE for its acronyms in Spanish), which has weighted the possibility of building a thermal power plant to supply the Brazilian market using Bolivian gas as a key resource.

The electric integration experiences between Brazil and its neighbors have been designed in its operational and commercial aspects to function properly in the Brazilian model. For example, although Itaipu was built long before the new model has been established (2004), the trade of energy for this plant had to be adapted to the new logic of the business model. Thus, Itaipu Binacional is part of the optimized dispatch of energy on the Brazilian system, which includes not only the supply of the domestic market, but also Paraguay's energy needs, which has different market arrangements than Brazil.

The original energy import contract from Argentina through CIEN also fit the Brazilian model, represented as a "frontier thermoelectric", which is dispatched when the hydrological situation required thermal energy complementation. In both cases, Itaipu Binacional and CIEN, the import of energy was possible because the commercial mechanisms adopted allowed the exporter to fit in the Brazilian operational logic . However, recent experiences of energy trade with Argentina and Uruguay followed a different logic.

When the importation of energy from Argentina, via CIEN, was unilaterally interrupted because of the energy crises in Argentina, finishing 20-year export contracts with Brazilian distribution companies, the frequency converters localized in Garabi began to be used occasionally to export power from Brazil to Argentina. These frequency converters are also sporadically used to allow the export of energy to Uruguay, passing through the Argentinian transmission system.

This energy export modalities practiced with Argentina and Uruguay are occasional. There is not a Brazilian commitment to export certain fixed amount of energy.Most of the time, the existing interconnections remain idle

Imports has a more complicated situation. The import of power by Brazilian agents is very difficult to be incorporated into the current trade model. Currently, besides the exchange of surplus of hydropower generation to be returned without involving any cash transaction, there is also the interruptible energy import from Argentina[15] and Uruguay[16]. This type of importation involves weekly energy offers on the border of Brazil[17] aiming the sell the energy in the spot market and being paid according to the Settlement of Differences Price (PLD for its acronyms in Portuguese). This energy can only be traded in the spot market because the generators do not have a certificate of “physical guarantee” in the Brazilian market, which prevents them to obtain incomes through sale contracts.

The integration method adopted with Argentina and Uruguay, which involves the export and import of energy in an interruptible basis without long-term contracts and taking advantage of short-term opportunities with relatively simple rules of commercialization, has shown the benefits of intensifying the trading of energy surpluses for all the parties. Contracts aiming the exportation / importation of firm energy are also possible if the certain conditions are created. These conditions must give effective legal certainty for such commercial arrangements.

In order to allow the exportation of firm energy through long-term contracts to the Brazilian market, it will be necessary to develop a technical and commercial arrangement to match energy imports to a power plant operating in an optimal way within the Brazilian system.

4.2 Outlook for import and export of electricity in Brazil

There are negotiations between governments for using the water resources on the border, particularly with Argentina on the Uruguay River (hydropower plants of Garabi and Panambi) [18] and with Bolivia in the Madeira River[19] basin, with a similar scheme used for Itaipu Binacional. However, any agreements for the construction of binational hydroelectric plant between Brazil and other partner should consider trade mechanisms consistent with the current model adopted in SEB.

In principle, these projects need to meet the same model of Itaipu Binacional, which is operated within the Brazilian model logic. In this sense, there are not major problems related to the use of this model in binational plant projects, especially for the quota of 50 % that will be owned by Brazil.

[15] Through the frequency converter of Garabi (MME, 2015- Portaria N°81).

[16] Through the frequency converter of Rivera and the future frequency converter of Melo (MME, 2015 – Portaria N° 82),

[17] The weekly energy offer to the ONS can be adjusted to the daily dispatch schedule.

[18] This project has significant progress with the hiring, in 2012, of the engineering and environmental studies, and also with the communication plan

[19] The addendum to Memorandum of Understanding in the field of electricity between Bolivia and Brazil was signed on July 2015 , which aims to enable the bi-national studies on the Madeira River

Building a hydroelectric plant dedicated in whole or in part to export energy to Brazil and use it in accordance to the Brazilian system operating logic will probably impose restrictions on the energy optimization needs. To consider the local demand of the exporting country and make a joint optimization of the system, would be required that consumers of the neighboring country were indeed part of the Brazilian market by acquiring financial contracts of "physical guarantee~~.~~". Although this hypothesis, which is equivalent to the adoption of the Brazilian business model by another country, cannot be ruled out, it is unlikely to be achieved in the short or medium term.

In the case of exporting thermal energy to Brazil, it would be possible to structure a similar contractual modeling to the original scheme of import of CIEN, but with greater legal certainty. For this, from the formal and contractual point of view, the signing of an International Treaty would be needed, raising the energy commercialization to a relationship between countries and not between electric companies, as was the case of CIEN. Presently there is not any plan for Brazil to import thermal power from neighboring countries

Due to the economic, political and energy asymmetries between Brazil and the other countries in the region, the major and faster opportunities for electric integration and international trade of electricity involving Brazil are the import and export of surpluses. The current contractual arrangements for energy trading adopted by Brazil with Argentina and Uruguay have used this logic and could be extended to other power plants. Important to notice that there is already a transport infrastructure to the Argentinian market and a large interconnection with Uruguay is being built.

Although there are functional mechanisms for trading energy surpluses using the existing interconnections, it is essential to create a legal, regulatory and commercial framework enabling the energy exchange of larger blocks of energy and with long-term contracts.

5 CONCLUSIONS

The energy integration process of Brazil, with respect to the electric sector can be divided in~~to~~ two phases. The first phase , which began in the 1970s , being the central focus the construction of the then largest hydroelectric of the world, Itaipu Binacional, which had a double and strategic goal: to ensure greater national supply with competitive costs.

The second phase of the integration process starts in 2003 and 2004, when Brazil redefined its strategic policy of regional economic integration, focused on Latin America. It is also important to highlight the role of power sector restructuration on 2003-2004. This process included: the recovery of state planning with the creation of EPE; use of new energy auctions as the main instrument for expanding the supply, formatting a new and consistent institutional framework and the BNDES role in financing the generation and transmission projects through the use of project finance mechanisms, directly linked to the auctions. This new model allowed Brazil to gradually return to exploit the hydroelectric potential, as well as creating a support for investments in wind energy, biomass from sugar cane and in generation from natural gas.

The business model was structured according to a unique and fundamental characteristic of the Brazilian power sector, the high prevalence of hydroelectric generation in the matrix. In this sense, the Brazilian model has specific characteristics that clearly distinguish it from the commercial arrangements prevailing in other Latin America countries. It is a model where energy itself is not traded, but financial contracts of "physical guarantee ". The electricity generating plants do not have contracts of physical energy and they do not have autonomy over its own production, being this determined by the ONS according to an optimization logic or all the electricity generation units.

In this sense, the electrical integration through the import and export of electricity in Brazil must respect the Brazilian business model. The characteristics and specificities of the Brazilian model determine boundary conditions that need to be observed in order to allow international trade of electricity. This involves, excepting for binational hydropower projects such as the project in the Madeira River with Bolivia and the hydropower plants of Garabi and Panambi with Argentina, that energy integration projects will depend on regulatory setting in order to adhere to the Brazilian business model. Especially for projects focused on exporting big blocks of electricity with long-term contracts and at competitive prices to the Brazilian electricity market.

In this sense, the dynamic of the electrical integration in South America with direct participation of Brazil is restricted to four possibilities. The first and simplest one, is the construction of binational hydroelectric plants based on the Itaipu Binacional successful experience. The production of a binational power plant is 50 % for each country and it is possible to define in the International Treaty that will endorse the trade agreement, the conditions for the trade of energy surpluses as was done with Paraguay in relation to Itaipu Binacional.

The second possibility is to model the energy imports by Brazil as a thermoelectric at the border, as happened with CIEN contract. This option is ideal for the import of thermal energy and its viability requires an understanding between countries, probably with an International Treaty to give legal certainty to commercial arrangement.

The third alternative, more complex, is the construction of hydroelectric plants (and the respective segments of transmission lines) in neighboring countries, and define the conditions for export to Brazil the portion of the energy production that won´t be consumed by the country of origin. The difficulties are great because the generating unit would have to submit to the Brazilian trade rules and to optimal and centralized dispatch criteria.

The fourth possibility is to trade energy surpluses in trade patterns that Brazil is already practicing, although sporadically, with Argentina and Uruguay. Selling and buying surpluses of power through short-term contracts that may be signed without a profound regulatory harmonization between the businesses models of the countries involved. In this case, each country seeks to ensure security of supply on its own market, counting in addition with the surpluses from a neighboring country and alternatively, with the option of selling the surpluses power. This type of integration has great scope for expansion, especially with countries with which Brazil already has interconnection.

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Load Profile Analysis Tool for Electrical Appliances in Households

F. Rodrigues[1,2], C. Cardeira[1], J.M.F. Calado[1,3], R. Melício[1,4]

[1]IDMEC/LAETA, Instituto Superior Técnico, Universidade de Lisboa, Portugal
[2]MIT Portugal, Porto Salvo, Portugal
[3]Departamento de Engenharia Mecânica, Instituto Superior de Engenharia de Lisboa, Portugal
[4]Departamento de Física, Escola de Ciências e Tecnologia, Universidade de Évora, Portugal

ABSTRACT

This paper presents a methodology to forecast the hourly and daily consumption in households. The methodology was validated for households in Lisbon region, Portugal. The paper shows that the forecast tool allows obtaining satisfactory results for forecasting. Models of demand response allow the support of consumer's decision in exchange for an economic benefit by the redefinition of load profile or changing the appliance consumption period. It is also in the interest of electric utilities to take advantage of these changes, particularly when consumers have an action on the demand-side management or production. Producers need to understand the load profile of households that are connected to a smart grid, to promote a better use of energy, as well as optimize the use of micro-generation from renewable sources, not only to delivering to the network but also in self-consumption.

KEYWORDS: Energy consumption, load management, supply and demand, smart grids, predictive models

1 INTRODUCTION

Nowadays, in an existing electric grid, it is important to understand and forecast household daily or hourly consumption with a reliable model for electric energy consumption and load profile in order to increase demand response programs required to adequate the profile of energy load diagram to generation. In short-term load forecasting (STLF) model artificial neural networks (ANN) have been used together with an energy consumption database [1–3]. In this paper, the database uses a model with the whole week (workweek and weekend). Using smart devices such as cyber-physical systems monitoring, gathering and computing in real time a database with weekdays and weekends, the use of these groups of days allows the development of STLF models with better results than a model using the whole week. Nevertheless, this paper shows that developed predictive tool allows obtaining satisfactory results for forecasting.

The average household electric energy consumption per year, from a set of 93 houses in Lisbon, Portugal, is about 3.251 kWh, i.e., 1.142 kWh per person or 28 kWh/m^2 [4]. The maximum consumption per year is 16.000 kWh.

The energy consumption of domestic appliances can be classified as:

a) Brown goods: TVs, VCRs, DVDs;

b) Cold appliances: refrigerators, freezers and combined fridge-freezer;

c) Cooking appliances: electronic ovens, electric hobs, kettles and microwaves;

d) Wet appliances: washing machines, tumble dryers and dishwashers;

e) Artificial lighting: Fluorescent tube, halogen lamp and incandescent bulb;

f) Miscellaneous appliances: vacuum cleaners, irons, electric showers, central heating pumps and PCs.

Unlike domestic appliances, artificial lighting energy consumption is highly influenced by season. The electric lighting on/off pattern also depends on daylight and occupancy pattern. If the internal required lighting level is less than the available daylight luminance level then artificial lighting will be switched on when the room is occupied. In winter, people get up in the morning and need the lights on for the activities, but in summer, lighting is not required due to the daylight.

Cooking appliances and miscellaneous appliances like kettle (boiler), iron and vacuum cleaner, this usage pattern also depends on the household occupancy pattern and lifestyle.

In Portugal, the hourly average load curve structure is the following: the heating and cooling representing about 16% of the total electricity of housing consumption; the lights representing about 9% of the total electricity consumption; the refrigerators and chest freezers representing about 20% of the total electricity consumption; the washing and dishing machines representing about 11% of the total electricity consumption; the cooking representing about 12% of the total electricity consumption; for domestic hot water 5% are consumed. Computers and other electrical and electronic entertainment are one of the areas with greatest growth in household consumption of energy. These facilities represent 14% and miscellaneous appliances 13% of total electricity consumption in a household [5].

In Lisbon, Portugal, it was possible to identify the structure of the daily load profile for the residential sector disaggregated by major end uses. The structure of the daily load profile for the residential sector disaggregated by major end uses for a set of 93 households in Lisbon [5] are shown in Fig. 1.

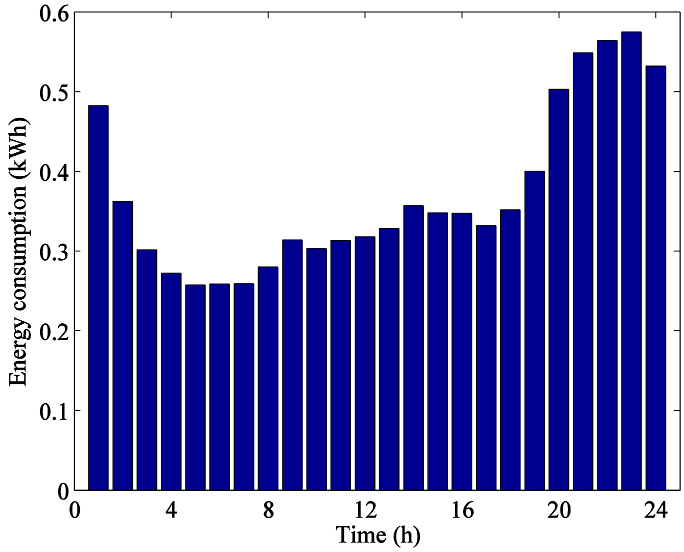

Fig. 1. The daily average electric consumption of a Portuguese set of 93 households.

In Fig. 1, in the evening peak period, there are three of the specific uses of electricity as lighting, cooling and audiovisual equipment that representing for more than a third of the total power required.

Based on information gathered from monitoring carried out by [4], the structure of the daily load of a household in Portugal is similar to a typical day load in a household in Europe, as shown “Load curve structure (yearly average), from the grid point of view and a typical household on a day of the year in Portugal and Europe” [4].

The structure of the load profiles shows the average hourly energy demand, from the grid point of view. These curves are averaged over a whole year, values are consumptions per hour. For a system planning and strategic design, also shows the breakdown daily energy-consumption for an average size household that can be useful for the microgeneration renewables energy and smart grid.

In our research, the structure of electricity consumption disaggregated by major end-uses was based on monitoring of 93 households held in Lisbon, Portugal, in 2000 and 2001, and which results are the below:

a) The distribution of apartments and villas in the samples were the following: 44% of the households are apartments. Moreover, the number of persons/household in the sample are 2.92, whereas in the country are 2.05 [4].

b) The number of inhabitants per household is always greater than the national averages. This is legitimate because they looked for households with the highest possible number of appliances, which usually are big and highly occupied households.

c) The average surface area of the households in the sample is 116.6 m^2.

d) The monitored households 66% used simple electricity tariffs and 28% were triphased. In the Portuguese sample only 6% of the households use electricity for domestic hot water (DHW). It is more common using the gas (Natural or LPG) for heating the DHW.

e) The average electric energy consumption in the Portuguese sample shown in Fig. 1 and is similar and have same profile as in [4].

The daily energy-consumption load profiles of electric appliance have been calculated using six weeks, including both workdays and weekend.

The predictive tool used is support by Solver that is a what-if analysis tool and dedicated to solve, among others, linear and non-linear optimization problems. It automatically finds close to optimal values for certain input cells, called decision variables. The solver ensures that these values satisfy limits, called constraints, on other cells calculated by formulas in the model. A designated formula cell, called the objective, is maximized or minimized at the near optimal solution.

2 STATE OF THE ART

The International Energy Agency (IEA) estimated that, even with a continuation of all existing appliance policy measures, the appliance electricity consumption will grow 25% by 2020 [6].

In all countries, four types of consumption seem to be rising particularly fast:

1) The domestic computers and peripherals;

2) New domestic entertainment;

3) Standby power;

4) Some lighting technologies, such as halogen lamps.

According to IEA, 15% of total appliance electricity consumption in Europe, by 2030, could be due to stand-by functionality.

Usage patterns associated with different sections of the population and the variations in consumers' knowledge/attitudes need to be identified. Possible links between cultural values and energy use should be explored in order to identify feasible means for promoting energy-rational behavior. The usage pattern is related to the occupied period. For example, when people are not at home, most appliances will not be used. In daily appliance electricity profile, the occupants use virtually little power (stand by and fridge-freezer) during the night, may wake up and have breakfast, vacate the house during the morning and then return around mid-day for lunch, in the evening, the meal is cooked, television is watched, and showers are taken, etc. The different households have different life styles. The total load profile shape will of course vary from day to day and house to house. The factors influencing the occupancy pattern are as follows:

a) The apartment area;

b) The number of occupants;

c) The time of the first person getting up in the morning and the last person going to sleep;

d) The period of the house unoccupied during the day.

It is important to identify the cluster of households when analyzing the load profile, because the load profile depends very much on the occupancy pattern. In the case of lack of information about household occupancy pattern, several scenarios, as proposed by [7] for household occupancy pattern, can be used.

The works [8,9] have demonstrated the role of monitoring in understanding the trends in electricity consumption in households and also established the need for qualitative and quantitative studies to explore the factors (technical, socio-demographic and behavioral) which influence these trends.

This work and others from the authors of this paper on these themes seek to identify the technical and behavioral patterns to identify predictive methods. Thus, this paper will describe a method and results obtained with a predictive tool proposed.

3 METHODOLOGY

This study creates a comprehensive residential energy consumption model using a tool from an energy consumption database from a set of 93 houses, recorded in Lisbon, in the years 2000–2001. Inputs include the apartment area, person/household, kitchen appliances, lighting, cooling and heating, domestic hot water (DHW) and entertainment appliances. The tool was trained using the mentioned database energy consumption. The trained model was then tested and compared with the annual energy consumption average.

Before using the tool, great part of the work was, firstly, to normalized the data in order to prepare the output layer for the training and testing. Six weeks of data, for every household, were used for validation. These values had an uninterrupted logged data along 6 weeks, which makes them adequate for the goals of this research.

The tool uses inputs from household and appliances (14 inputs), an array of 14 x 12, the first being the inputs of electrical column and lines the daytime hours (01:00 to 12:00 or 02:00 - 24: 00). For the calculation of each array value, the solver uses the Generalized Reduced Gradient (GRG) Algorithm for optimizing nonlinear problems.

The GRG method is another popular state of the art technique. The original method, the Reduced Gradient Method has seen several different customizations due several researchers [10–13].

The GRG is a generalization of the reduced gradient method by allowing nonlinear constraints and arbitrary bounds on the variables. The form is:

$$\max\ f(x) : h(x) = 0, L \leq x \leq U \tag{1}$$

where h has dimension m. The method supposes that can be partition $x = (v, w)$ such that:

- v has dimension m (and w has dimension n-m);
- the values of v are strictly within their bounds: $Lv < v < Uv$ (this is a non degeneracy assumption);
- $\nabla_v\, h(x)$ is nonsingular at $x = (v, w)$.

As in the linear case, for any w there is a unique value, *v(w)*, such that *h(v(w), w) = 0* (c.f., Implicit Function Theorem), which implies that:

$$\frac{dv}{dw} = (\nabla_v h(x))^{-1} \nabla_w h(x) \tag{2}$$

The idea is to choose the direction of the independent variables to be the reduced gradient:

$$\nabla_w (f(x) - y^T h(x)) \tag{3}$$

where

$$y = \frac{dv}{dw} = (\nabla_v \ h(x))^{-1} \nabla_w \ h(x) \tag{4}$$

Then, the step size is chosen and a correction procedure applied to return to the surface, *h(x) = 0*.

The main steps (except the correction procedure) are the same as the reduced gradient method, changing the working set as appropriate.

The GRG method is quite efficient for problems of this type because it uses linear approximations to the problem functions at a number of stages in the solution process. Because the first derivative (or gradient) of the optimum cell measures its rate of change with respect to (each of) the adjustable cells, when all of the partial derivatives of the optimum cell are zero (that is, the gradient is the zero vector), the first-order conditions for optimality have been satisfied having found the highest (or lowest) possible value for the optimum cell. For an optimization solution it was used the minimum square error (MSE), which has been found very useful for constraint variables to solve the model.

To performed de GRG, a matrix that is presented below was developed as Table 1 to produce the weights for each appliance, which are listed in the first column, and will weigh for each hour of day simulating the average consumption of each mentioned appliance. Data from the previous weeks' consumption of each household enabled the development of the matrix of weights applied in the following days.

Table 1. Matrix developed to produce weights (αi,j) of daily average consumption of an household

Household	α_1	α_2	α_3	α_4	α_5	α_6	α_7	α_8	α_9	α_{10}	α_{11}	α_{12}
Nº x	01:00	02:00	03:00	04:00	05:00	06:00	07:00	08:00	09:00	10:00	11:00	12:00
Area	A_x	A_x	A_x	A_x	A_x	A_x	A_x	A_x	A_x	A_x	A_x	A_x
Inhabitants	I_x	I_x	I_x	I_x	I_x	I_x	I_x	I_x	I_x	I_x	I_x	I_x
Appliance												
1	$\alpha_{1,1}$	$\alpha_{2,1}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,1}$
2	$\alpha_{1,2}$	$\alpha_{2,2}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,2}$
3	$\alpha_{1,3}$	$\alpha_{2,3}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,3}$
.	$\alpha_{1,.}$	$\alpha_{2,.}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,.}$
.	$\alpha_{1,.}$	$\alpha_{2,.}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,.}$
.	$\alpha_{1,.}$	$\alpha_{2,.}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,.}$
14	$\alpha_{1,14}$	$\alpha_{2,14}$	---	---	---	---	---	---	---	---	---	$\alpha_{12,14}$

To assign the minimum weight of each variable associated to the appliance in the matrix and, through GRG, calculate $\alpha_{i,i}$, from table 1, it was set up a function in order to minimize the MSE of the electrical consumption and the real average consumption of each household.

The MSE can be estimated by:

$$MSE = \frac{1}{n}\sum_{i=1}^{n}(\bar{\alpha}_i - \alpha_i)^2 \tag{5}$$

for the mean is the sample average

$$\bar{\alpha} = \frac{1}{n}\sum_{i=1}^{n}\alpha_i \tag{6}$$

An MSE of zero, meaning that the weight of the $\alpha_{i,j}$ is with perfect accuracy, is the ideal, but is practically never possible, as show the results. The goal of using MSE was to experiments in such a way that when the observations are analyzed, the MSE is close to zero relative to the magnitude of the estimated forecasting.

4 SIMULATION RESULTS

The study model and database, electric appliance load profile has been validated in [4] and based on information gathered from monitoring carried out by [2].

To optimize the solution and identify the type of function (linear or nonlinear) it was used the GRG method used by Solver. The results showed the functions of daily electricity consumption are nonlinear and the optimization tool can be used to forecast annual energy consumption average.

Using GRG, the research was shown the ability to converge the forecasting function to the function of real consumption with an error MSE ≅ 0.

The Comparison of an average annual consumption per day with accumulative energy consumption electric appliance forecasting are shown in Fig. 2.

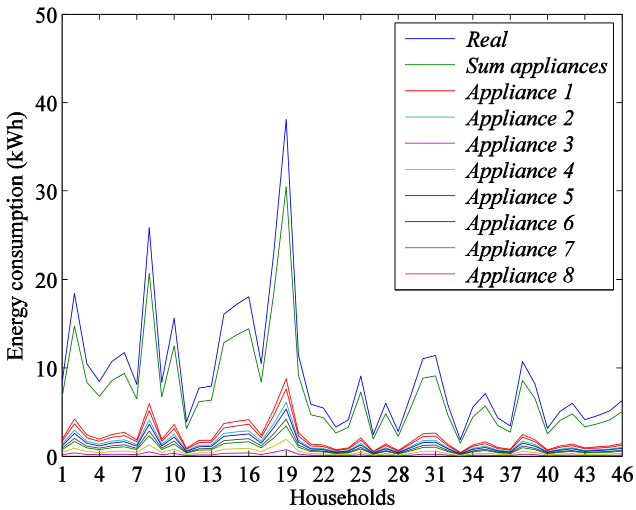

Fig 2. Comparison of an average annual consumption per day with accumulative energy consumption electric appliance forecasting.

Fig. 2 shows the modeling tested results of Portuguese household average annual consumption per day. The horizontal axis identifies the household number. The vertical axis shows the average annual daily consumption in kWh per day. The straight blue line (from de top, first one) represents the total real average annual daily electric energy consumption. The green line (second) represents accumulated average annual electricity consumption from appliances forecasting. Other colors represent the contribution of each electric appliance forecasting energy consumption in each household. For this contribution, the values used by electric appliances are energy consumption forecasting from GRG computations.
The comparison of hourly energy consumption average using electric appliance forecasting is shown in Fig. 3.

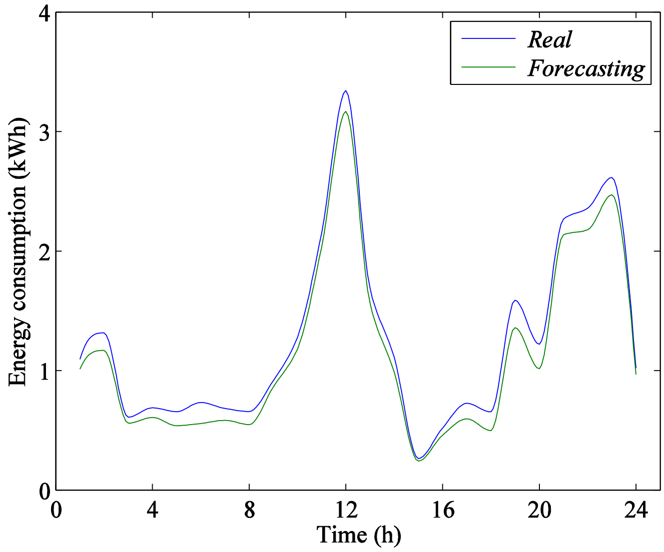

Fig 3. Comparison of hourly energy consumption average using electric appliance forecasting.

Fig. 3 shows the modeling tested results of household hourly energy consumption average. The blue line represents the hourly electric energy consumption average and the green line represents the consumption weights and the contribution of each appliance in a household.

These results, which are the hourly and daily average energy consumption, have an important role in shaping the design of storage energy. Knowing the forecasting consumption, power production and hourly energy demand is possible shedding (anticipate or postpone) the consumption of electricity.

The tool developed can be used at the renewable energy system early design stage. It can also help the electricity supplier to forecast the likely future development of electricity demand in the whole sector of the community.

5 CONCLUSION

This paper introduced simple forecast methods of daily and hourly average energy consumption, by using an optimization tool. The paper reveal that tool is able, after identifying the methods, forecast hourly and daily average energy consumption, as well load profile. This tool uses the Generalized Reduced Gradient method.

The input data included the apartment area, inhabitants, kitchen appliances, lighting, cooling and heating, domestic hot water and entertainment appliances.

The method is based on electric consumption and occupancy patterns. Hourly and daily measurements of end-users energy consumption are used for generalizing the load profile.

A load profile for 47 households, i.e., half of database has been generated for training. Verifying against the other half, the load forecasting kept close to the real consumption.

Forecast daily and hourly energy consumption can be useful in to determine the required size of a storage energy systems, delay and postpone energy consumption. The used method can be used at the renewable energy system early design stage and improve smart grid performance. It can also help on the demand-side management, such as electricity suppliers, to forecast the likely future development of electricity demand in the whole sector of the community.

For the future, an important step in continuing is additional research enhancing forecasting capability on the load profile renewable energy production (micro production), include testing the method for different day of the week (weekday, weekend and holiday days). The purpose of forecasting energy consumption daily and hourly is to identify an accurate, effective and sufficient, renewable energy production and energy storage.

ACKNOWLEDGEMENTS

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Collateral effects of liberalisation: metering, losses, load profiles and cost settlement in spain's electricity system

Joan Batalla-Bejerano[1], Maria Teresa Costa-Campi[2], Elisa Trujillo-Baute[3]

[1] Rovira i Virgili University and Chair of Energy Sustainability, Av. Diagonal, 690, 08034 Barcelona (Spain), e-mail: jbatallab@gmail.com (corresponding author)

[2] University of Barcelona and Barcelona Institute of Economics (IEB), Chair of Energy Sustainability, Av. Diagonal, 690, 08034 Barcelona (Spain), e-mail: mtcosta@ub.edu

[3] University of Warwick, Barcelona Institute of Economics (IEB) and Chair of Energy Sustainability, Coventry CV4 7AL (United Kingdom), e-mail: elisatrujillo@ub.edu

Abstract

European energy markets have undergone a major transformation as they have advanced towards market liberalisation and it is vital that the details of these developments be carefully examined. The success of liberalisation is based on smart regulation, which has been capable of providing solutions to unforeseen events in the process. Our paper seeks to contribute to existing understanding of the unexpected and collateral effects of the liberalisation process in the power system by examining a natural experiment that occurred in Spain in 2009. In that year, the electricity supply by distribution system operators disappeared. This change in retail market competition, as we demonstrate in this paper, has had an unexpected effect in terms of the system's balancing requirements. We undertake a rigorous assessment of the economic consequences of this policy change for the whole system, in terms of its impact on final electricity prices.

Keywords: electricity market design, balancing services, electricity market balance; liberalisation; natural experiment.

1. INTRODUCTION

In the 1990s, when most national electricity and natural gas markets were still monopolies, the European Union and its Member States opted for the gradual opening up of these markets to competition. Significant progress has since been made in this direction in the case of the electricity market thanks to the gradual introduction of competition via a number of legislative packages. Underlying these proposals is the strong conviction that liberalisation increases the efficiency of the energy sector and the competitiveness of the European economy as a whole.

Spain has been no exception in this liberalisation process. In line with the broader trend, the Spanish government established as a priority the opening up of the electricity sector to competition. The Electric Power Act 54/1997 represented the first step in this liberalisation process, with the establishment of a general framework for the electricity sector aimed at guaranteeing competition and competitiveness. Under this new framework, the government defined a transition period towards full liberalisation and while the introduction of tariffs of last resort in the residential electricity market did not increase liberalisation per se (Federico, 2011), it did represent a starting point in the drive to the deregulation of the retail market.

An evaluation of the liberalisation process conducted to date across Europe shows that not all the expected changes, especially those concerning lower electricity prices and effective retail market competition, have yet to be achieved. However, it is not the aim of this paper to analyse the results of the liberalisation process; rather, our objective is to examine some collateral or unexpected effects of the liberalisation process in the energy sector by examining a natural experiment conducted in Spain in 2009. The Second Electricity Directive[1] and its transposition to national regulation included a number of measures directly concerning distribution system operators (DSOs). Thus, the regulatory framework required the separation of distribution activities from other segments of the electricity value chain (i.e., generation, transmission and supply activities). In the case of Spain, prior to June 2009, distribution companies had also been responsible for supplying consumers under a regulated tariff. However, in July 2009, this regulated supply disappeared and was substituted by a last resort supply system, managed by suppliers of last resort. This change in retail market competition, as we shall demonstrate in this paper, has had consequences in terms of the system's balancing requirements.

An increase in the adjustment service costs of tertiary regulation and deviation management have been observed since 1 July 2009, together with an increase in the corresponding adjustment service costs incorporated in the final electricity price paid by consumers. The aim of this study is to provide a better understanding of the impact of liberalisation on the costs of volume adjustment. We exploit this policy event to compare the costs of adjustment in the periods before and after the policy change. Although demand forecast methods have received special attention from the academia (Cancelo et al., 2008; Ramanathan et al., 1997; Soares and Medeiros, 2008; Taylor, 2006;), when explaining the cost of balancing services, demand deviations effects have not been as deeply studied as the effects that stem from intermittent renewable generation (Ela et al., 2014; Frunt, 2011; Glachant and Finon, 2010; Haas et al., 2013; Hirth and Ziegenhagen, 2015; Hirth et al., 2015; Vandezande et al., 2010).

[1] Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

Within the overall liberalisation process, during which European energy markets have undergone a major transformation, the issue analysed in this paper - energy market balance - could be considered a minor question. However, the success of any transformation process lies in applying smart regulations that can provide solutions to unexpected aspects of the process so as to exploit its potential benefits for society. In this new liberalised paradigm, the System Operator (SO) has to be more concerned with real-time system operations and the ability to manage supply and demand constantly given that additional demand deviations induced by the energy market balance can potentially result in new operational reliability issues that need to be analysed.

In this context, drawing on data for the Spanish power market for the period just before and after the regulatory change became effective, this study aims to address the question of the collateral consequences of the liberalisation process in terms of system reliability. The paper seeks to determine whether this policy change means that additional system flexibility is required thus affecting final electricity prices insofar as increasing energy market balance is addressed through ancillary services. Although the liberalisation process undertaken in Spain goes beyond the disappearance of the regulated supply and its impact on power system balancing costs, it is crucial to assess its economic consequences, especially if the last intention of the regulatory change is to benefit all electricity consumers.

The remainder of this paper is structured as follows. Section 2 provides an overview of the policy change under revision and its economic implications. The data used, empirical strategy and model specification are presented in Section 3. Estimation results are presented and discussed in Section 4. The paper ends with a final section summarising research conclusions and presenting the policy and regulatory recommendations.

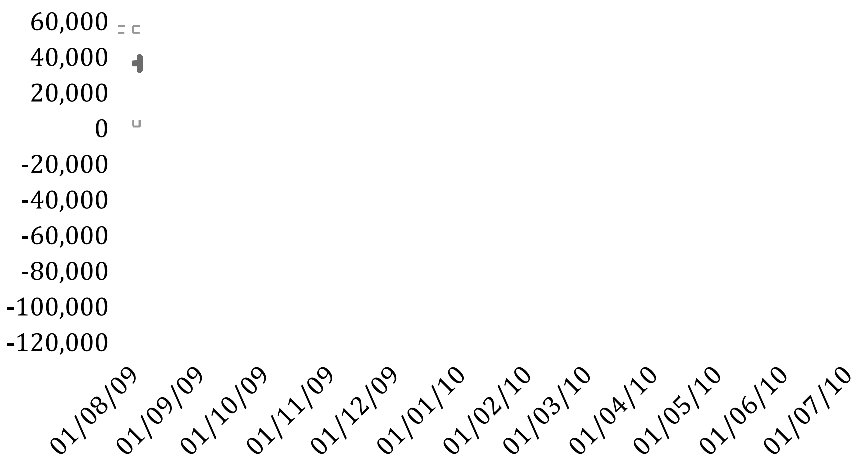
2. THE POLICY

2.1. Policy design

2009 was a key year for Spain's electricity sector and, in particular, for its retail markets. On 1 July 2009, end-user regulated electricity prices disappeared along with the DSOs' role as suppliers. Prior to that date, consumers had been able to choose between being supplied by distribution companies – through end-user regulated prices – or by retailers under free market conditions. Distribution companies would no longer be able to supply electricity to their customers.

However, these reforms, which were designed to foster competition in the retail market and to promote progress towards the creation of an efficient Internal Energy Market in the European Union, had collateral and negative consequences for balancing markets in relation to electricity system losses and the estimation process of the electricity consumption for those customers without hourly metering. As the energy metered at distribution network entry points (transmission nodes and embedded generation) is not the same as that metered at distribution network exit points owing to the existence of losses, energy demand at the power station busbars[2] is estimated using a regulated standard coefficient of losses. It should be stressed that the energy estimated according to this procedure does not have to coincide with the amount of energy eventually dispatched, arising hourly energy imbalances (see Figure 1). As a result, the energy dispatched to meet the customers' energy requirements is not necessarily the same as that initially expected by the suppliers, appearing a positive or negative energy difference, for which a balancing process is required.

Figure 1: Hourly energy imbalances (MWh)
explained by differences between real and estimated electricity losses



Source: Own elaboration based on data from Spanish National Regulatory Authority (CNMC)

The main difference since July 2009 is the way in which this new energy imbalance is addressed[3]. In the pre-liberalisation system, the energy imbalance was resolved by the DSOs permanently matching electricity demand forecasts with the energy actually dispatched. Under liberalisation, this system is no longer valid. From a regulatory perspective, the electricity imbalances resulting from the difference between the average transport and distribution losses and the standard losses used in balancing the system as a whole are considered additional system deviations. This difference, defined as the energy market balance (EMB), requires additional adjustment services to ensure that energy generation and demand are in permanent equilibrium. Addressing the energy market balance is achieved through ancillary and energy balancing services based, in most instances, on market procedures such as the secondary and tertiary reserves and the imbalance management process, so there is a direct relationship between the size of the deviation and the cost to the system when solving it.

[2] The power plant busbar is that point beyond the generator but prior to the voltage transformation in the plant switchyard; it is the starting point of the electric transmission system.

[3] See Appendix for a detailed explanation of the technical aspects underpinning the energy market balance (EMB).

The analysis of the relationship between the energy market balance and the final electricity price is the main objective of this paper. When a difference arises between the energy measured at the power station busbars and the energy scheduled in the market, the system has to manage that difference by increasing production through the adjustment markets in real time. As explained next, the energy market balance implies economic consequences for both suppliers and consumers, who have to face increasing balancing costs related to the energy adjustment mechanism required to maintain generation and load in permanent equilibrium.

2.2. Implications and research hypothesis

From a system management perspective, several factors on both the demand and supply side might cause active power imbalances in the electricity system (see Table 1). Together with physical imbalances, above and beyond the deviations between the stepwise (discrete) demand and supply schedules and continuous physical variables (scheduled leaps), other variables may result in imbalances. Thus, unplanned contingencies in the conventional or renewable generation capacity or in the interconnection capacity, forecast errors from VRES generation due to its intermittent nature or load forecast errors can all increase the need for balancing power. As the electrical system has to be in permanent equilibrium, balancing power (regulating frequency-control power) is used in rapidly restoring the supply-demand balance in systems when an active power imbalance arises.

Table 1: Variables that cause system imbalances

	Variable	Imbalance source
Supply	Conventional generation	- Unplanned plant outages - Schedule leaps
	VRES generation	- Forecast errors - Schedule leaps
	Interconnectors	- Unplanned line outages - Schedule leaps
Demand	Load	- Forecast errors - **Deviations from standard losses** - Schedule leaps

Source: based on Hirth and Ziegenhagen (2015)

As explained above, total losses produced in the transmission and distribution networks may be another source of power imbalance. The methodology employed in the Spanish regulatory framework in relation to such losses involves allocating a percentage of these losses to each customer using loss factors or standard coefficients that take into account their consumption characteristics. This procedure means that if actual losses differ from standard or regulated losses, the power system has to face a new source of imbalance.

The existence of demand deviations in power systems is not something new. The aim behind the liberalisation process across Europe implemented during the last decade was to open up the electricity supply to competition. At that moment, and in order to avoid huge and prohibitive costs of putting smart metering into every customer, it was a common approach that some specific electricity consumers – mainly residential – would be settled using load profiles and ex-ante fixed loss coefficients. In this sense, deviations from standard losses have to be considered as an additional source of uncertainty to power system managers together with the inherent forecast errors and schedule leaps.

In this context and even with perfect VRES-E generation forecasting, *ceteris paribus* the consequences for electricity systems of an increasing difference between the estimated demand and the final load should be a need for additional flexibility. In terms of system operation, this energy gap should stress the need for an appropriate number of reserve power plants with flexible dispatch capable of providing the necessary stability and ancillary services to deal with problems of electricity market balance.

In this paper, we test whether a sub-optimal definition of the standard coefficient of losses means that the system operator has greater losses to solve in real-time in order to balance the markets. At the same time, we examine whether the way in which this policy consequence is being addressed affects the market price signals for the rest of the balancing energy required.

The Spanish electricity market is organized as a sequence of different markets – a day-ahead market, an intraday market, ancillary services – and system operation services beginning with the day-ahead market and culminating in real time[4]. Once the day-ahead market closes, additional short-term tools have to be implemented to enable participants or the system operator to improve the schedules defined during the previous day (Pérez-Arriaga and Batlle, 2012). Under trading enabling them to react when supply or demand situations change with respect to the estimates cleared on the day-ahead market. Finally, ancillary services include the set of products that are separated from the energy production, and which are related to the power system's security and reliability (Lobato et al., 2008). These services, though not including voltage control ancillary services, are designed to ensure the necessary equilibrium between generation and demand and include load-frequency control and balancing ancillary services.

Although a detailed description of the design and characteristics of the different ancillary service (AS) markets – primary control, secondary control, tertiary control and balancing ancillary services – lies beyond the scope of this paper, Figure 2 illustrates the expected effects of the policy under analysis on AS markets. To understand these effects properly, a number of considerations must first be made. In Spain, as in most countries' power systems, several types of balancing power are employed simultaneously to address power and load imbalances. These balancing power types can be distinguished along several dimensions (Hirth and Ziegenhagen, 2015): operating vs. contingency reserves, spinning vs. stand-by reserves, fast vs. low regulation in terms of the activation time, positive or upward regulation

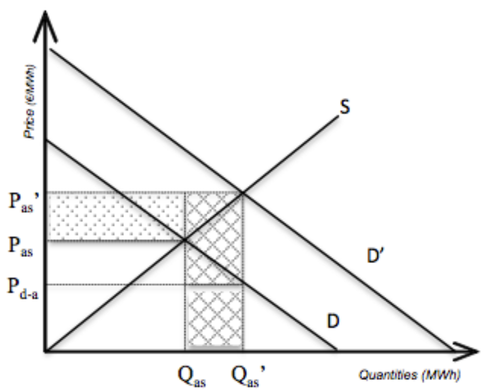
[4] For a more detailed description of the Spanish electricity market see Bueno-Lorenzo et al. (2013).

vs. negative or downward regulation, etc. Depending on the type of balancing power market, the technical characteristics of the service provided differ. Thus, each has different market designs and different ways of addressing resource adequacy and reserve margin issues. To explain the expected consequences of the policy change in the ancillary services market, in Figure 2 we assume that all the balancing energy required to solve imbalances is cleared in a single competitive balancing market, where suppliers of balancing power only receive compensation for energy (and none for capacity) based on the marginal price.

In the simplified ancillary services market, the market equilibrium price (P_{as}) results from the intersection of the demand (D) and supply (S) curves. This price determines the economic cost associated with the provision of the balancing energy required (Q_{as}) by the System Operator to stabilize the active power balance on short time scales. The electricity market balance process used to solve biased loss estimations might increase the total amount of balancing power needed thus leading to a change in demand. Graphically, this new balancing requirement ($Q_{as}' - Q_{as}$) involves a shift in the demand curve to the right (D') resulting in a new market price equilibrium (P_{as}').

Two direct economic effects can be identified if we examine the policy implications of balancing market. The first (the *quantity effect*) concerns the increase in the total balancing cost needed to reserve the band of secondary regulation and for the additional spinning reserves for tertiary purposes caused by EMB $((Q_{as}' - Q_{as}) \times P_{as}')$. Additionally, an increase in demand will shift prices upward, increasing the overall economic value of balancing relative to the prior equilibrium point. This second impact (*price effect*) concerns the increase in the total balancing cost explained by a higher equilibrium price than that at which the previous equilibrium quantity is cleared $(Q_{as} \times (P_{as}' - P_{as}))$. Both effects refer to the total economic cost of balancing power procurement. In this paper, we test if liberalisation (i.e., the policy change) results in a shift of both the price and quantity in balancing markets, increasing the overall cost of the provision of this service relative to the prior equilibrium point.

Figure 2: Expected effects of the policy on ancillary services market



At different market sessions held the day prior to or even on the day of delivery, the final price of electricity is determined as the sum of the different prices and costs associated with each of these markets. The determination of the economic cost associated with each electricity market and the allocation criteria of this cost strongly depend on market design characteristics. Increasing energy market balance is addressed through ancillary and energy balancing services based, in most cases, on market procedures such as secondary and tertiary reserves and imbalance management processes, so there is a direct relationship between the size of the deviation and the cost to the system for solving it. Demand for larger balancing energy might have economic impacts on final electricity prices and the analysis conducted in this paper seeks to obtain empirical findings of this nexus based on Spanish market data.

Power system reliability and resource adequacy are complex elements of market operations where the final cost is influenced by multiple factors. While there is, in principle, a general consensus on the nexus between energy loss deviations from expected and balancing power, no empirical analyses have examined the size of the impact. The absolute economic impact of the policy change in terms of balancing costs is by no means a straightforward question due to the complex nature of wholesale, intraday and ancillary services markets where many variables can impact on final prices and generator revenues (location, raw material costs, generation mix, level of demand, size of the electricity imbalances, etc.). The aim of this paper is to contribute to a better understanding of the economic consequences of the liberalisation by undertaking an evaluation of its impact on final balancing power cost.

From a welfare perspective, the economic consequences for consumers are evident as the energy imbalance is addressed in posterior markets where prices are typically higher. Real-time market clearing prices, also known as balancing energy prices, are generally by their nature much more volatile and higher than day-ahead prices. Therefore, an increase in the volume of balancing energy required to solve deviations between estimated and real loads should have an economic impact on the final hourly electricity price paid by the consumers.

3. DATA AND EMPIRICAL STRATEGY

As explained above, the Spanish electricity market comprises different sub-markets: a daily market, an intraday market, ancillary services and system operation services beginning with the day-ahead market and culminating in real time. The system operator, Red Eléctrica de España (REE), manages the primary, secondary and tertiary regulation, in order to guarantee the stability of the system. All the adjustment services are made available via different system operation processes defined by REE. One of the most remarkable features of the Spanish system is that, since the beginning of the liberalisation process, the regulatory framework has promoted the provision of these services through market mechanisms, along with the creation of the market as a platform for energy transactions. Drawing on data for these markets, operating reserve costs have been calculated. Operating reserves, often referred to as ancillary services, include contingency reserves – the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage – and regulation reserves – the ability to respond to small and random fluctuations around the expected load (Ela et al., 2014; Hummon et al., 2013; IEA, 2009, 2011a and 2011b).

As pointed out in previous sections, deviations between scheduled energy and real time demand are addressed through ancillary services, most of which are based on market procedures, such as the secondary and tertiary reserves and the imbalance management process. Therefore, there is a direct relationship between the size of the deviation and the cost to the system of solving it. Using hourly market data for Spain, the weighted average cost of the system adjustment services – technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints – is used as the dependent variable in the econometric estimation. To examine the impact of the policy we distinguish between two periods. The first covers the 12-month period prior to policy change, from 1 July 2008 to 30 June 2009. The second covers the 12-month period after the policy became effective, from 1 July 2009 to 30 June 2010. We choose one-year periods to minimise the probability that seasonal patterns might account for the results we find. We looked for information about other related policy changes in both periods that might affect our research, but to the best of our knowledge there were none. Hence, we are confident that the policy change under consideration is the sole policy event in our sample.

The adjustment (or operational) cost, defined as the economic cost of the balancing mechanisms that are required when demand or supply deviations appear, is defined as the price spread between the final electricity price and the price at the end of the last intraday market session. After the intraday market, deviations between scheduled and measured energy are addressed through market procedures, such as secondary reserve, tertiary reserve and the imbalance management process. The costs associated with these balancing markets are captured by this spread, which measures the additional costs for delivering one MWh of electricity on top of the day-ahead and intraday price. When obtaining this spread, capacity payments[5] are not considered. In other words, the adjustment cost results from the aggregate of the overall system adjustment services managed by the SO – technical and real-time constraints, power reserve, secondary and tertiary control bands and deviation management services -

Based on the foregoing considerations and bearing in mind that the final electricity price is determined as the sum of the different prices and costs associated with each of the markets that integrate the power system, the adjustment service cost (ASC) is obtained as shown in the following equation (with all variables expressed in €/MWh):

$$ASC_t = FP_t - DAMP_t - IMP_t - CP_t \qquad (5)$$

where:

ASC_t:	Adjustment service cost
FP_t:	Electricity final price
$DAMP_t$:	Day-ahead market price

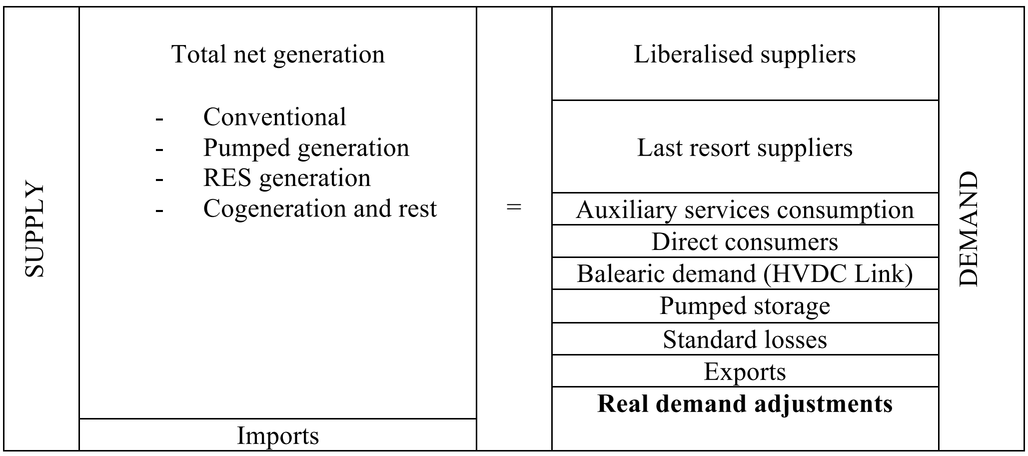
[5] Capacity payments correspond to the regulated retribution to finance the medium- and long-term power capacity service offered by the generation facilities to the electricity system. Given that they are not directly related to the procurement of flexibility to the system, this cost is not included.

IMP_t: Intraday markets price
CP_t: Capacity payments

Although several factors – unplanned plant outages in thermal and hydro generation, forecast errors in VRES-E generation, unplanned line outages of international interconnectors and forecast errors of load, among others – could result in active power imbalances in electricity systems, our empirical approach focuses on demand deviations explained by differences between the real losses of the system and those resulting from the application of a standard coefficient of losses and load profiles.

To understand how this explanatory variable is calculated, we first need to provide an overview of how active power imbalances are addressed in Spain's electricity system. As electricity cannot be stored in large quantities, the amount of energy demanded must be generated with great precision in the exact moment that it is required, ensuring a constant balance is maintained between generation and consumption. Using day-ahead market and physical bilateral contracts, purchase and sales bids are made resulting in the scheduled energy program. From the perspective of energy flows (Figure 3), demand and supply are integrated by different components. Following intraday market gate closure, the SO has to adjust the resulting program to compensate for any modification or deviation in any of these components. Energy deviations that occur after the intraday gate closure constitute real demand adjustments (RDAs), the latter being attributable to several possible factors. Any difference between expected and real demand from liberalised and last resort retailers (without considering technical and commercial losses) or any real losses different from expected standard losses, increase the need for energy used in the RDA process. Given that demand deviations explained by EMB constitute one of the most relevant explanatory variables accounting for RDAs, they have been used as a proxy variable of the effect of the policy under analysis.

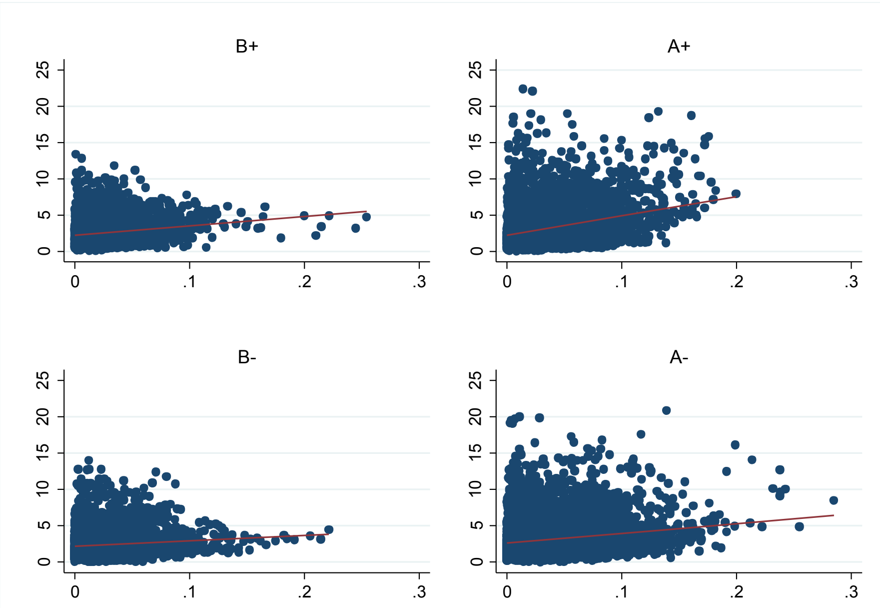
Figure 3: Spanish (peninsular) electricity balance



Source: Own elaboration

Figure 4 shows the relationship between RDAs in relative terms and the ASCs in the Spanish market as a price spread. The graphs on the left show this relationship before the policy change while the graphs on the right show the relationship after the policy change.

Figure 4: Adjustment service costs versus real demand adjustments. This figure shows the relationship between the price spread explained by adjustment service costs (€/ MWh) (y-axis) and real demand adjustments[6] (x-axis) before (B) (left hand side) and after (A) (right hand side) the policy change.



Given that for the Spanish electricity market, according to the imbalance price policy, a two-price system scheme is used depending on the overall system situation, the analysis of the relation between the two variables needs to take this into consideration. Therefore, for the graphical representation we split the sample in two, depending on whether the system is characterised by over-deviations (long system position) and requires downward regulation energy (-) or by under-deviations (short system position) and requires upward regulation energy (+).

As a different imbalance price is applied to positive and negative imbalance volumes, the analysis of the relationship between RDA in relative terms and adjustment services takes into consideration this fact, resulting in four possible scenarios: the relationship prior to policy change for hours requiring upward regulation energy (B+) or downward regulation energy (B-) and after the policy change for hours requiring upward regulation energy (A+) or downward regulation energy (A-).

It seems quite apparent that the policy change has affected the relationship between RDAs and ASCs. First, both the graphs (Figure 4) and statistics (Table 2) suggest an increase in dispersion in terms of adjustment services with the highest costs being recorded following liberalisation. As for RDAs, the graphs suggest a similar increase. At the same time, graphic analyses seem to indicate a change in the nature of the relationship between the two variables.

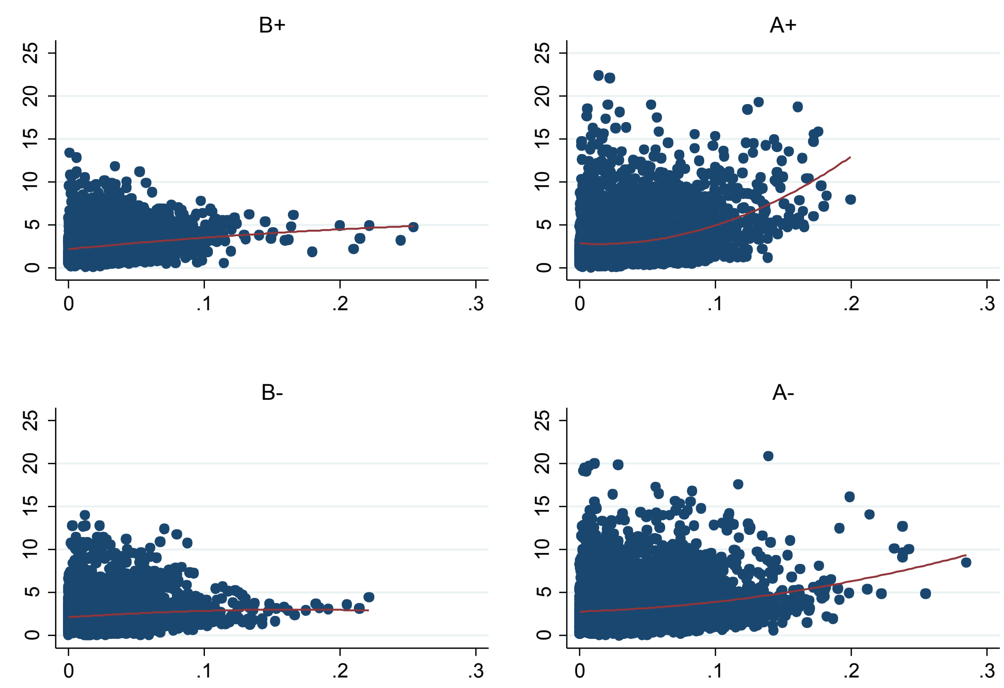
[6] For simplicity of exposition we refer to the real demand adjustment in relative terms (% over hourly final electricity demand) as real demand adjustment.

Table 2: Statistical representation of Figure 4

			Obs.	Mean	Std. Dev.	Min	Max
Real Demand Adjustments	Before	Negative	5219	0.02908	0.02484	0	0.22114
		Positive	3540	0.02632	0.02422	8.81E-06	0.25394
	After	Negative	5193	0.04491	0.0348	0	0.28484
		Positive	3566	0.03963	0.0319	3.13E-06	0.19958
Adjustment Service Costs	Before	Negative	5219	2.35953	1.62451	0	13.91
		Positive	3540	2.54883	1.67132	0	13.34
	After	Negative	5193	3.18603	2.5450	0	20.79
		Positive	3566	3.25166	2.93304	0	22.37

After the policy change, in contrast with the situation prior to liberalisation, the graphic representation suggests that the relationship is no longer linear and is better fitted by a quadratic function. Indeed the scatter plots in Figure 5 seem to reveal a slight curvilinear shape to the data suggesting that a second-degree polynomial might be appropriate for modelling the data after the policy change.

Figure 5: Adjustment service costs versus real demand adjustments (quadratic relationship)



Therefore, both the linear and quadratic specifications are tested econometrically by performing two separate regressions (before and after the policy change). By including a dummy variable for liberalization interacted with the real demand adjustment (RDA) variable we could be able to capture the effect from the variable of interest. Nevertheless, when using the interacted dummy an underlying assumption is that the relation between the adjustment service cost (ASC) and the RDA it is linear during all the period. Given that for the period after the regulatory change the relation it is better fitted by a quadratic function, it seems more appropriate to split the sample instead of using the interacted dummy over the entire period.

To conduct the econometric test, we use hourly market data for Spain for the period between 1 July 2008 and 30 June 2010, and construct a time series regression model controlling for seasonality. As the dependent variable, the econometric estimation uses the average weighted cost of the adjustment services. This variable, obtained as a price spread, includes the economic cost associated with all adjustment services – technical constraints, secondary control, tertiary control, power reserve, deviation management and real-time constraints. Hourly RDAs are used as the main explanatory variable.

Additionally, and in line with other electricity market price studies, we introduce an autoregressive component to capture dynamic effects on the adjustment costs. We introduce two additional control variables in our models. First, to control for consumption patterns on working and non-working days, we introduce a working day variable (*WD*). As electricity demand varies across the week, this temporary variable is introduced in the specification of the model in order to address aspects related to seasonality. Given notable differences between working days and the weekend, the model specification incorporates a dummy variable (=1 if a working day). Second, as the price of balancing power differs being on average positive balancing more expensive than negative balancing (Table 2), we introduce a second control variable (*UpR*) for upward and downward energy regulation (=1 if the electricity system requires upward regulation). In Table 3, we present the descriptive statistics of the variables employed.

Table 3: Summary statistics

Variable	Obs.	Mean	Std. Dev.	Min	Max
ASC	17518	2.82441	2.27529	0	22.37
RDA	17518	0.03536	0.03048	0	0.28484
WD	17518	0.69726	0.45946	0	1
UpR	17518	0.40570	0.49104	0	1

Before presenting the time series regression models constructed for the analysis of the impact of the real demand adjustment on the adjustment cost, a stationary time series analysis was performed. We performed two tests: first, the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) under the null hypothesis of a unit root; and, second, the Kwiatkowski-Phillips-Schmidt-Shin (KPSS) tests (Kwiatkowski et al., 1992) under the null hypothesis of stationarity. Both tests[7] confirm that the series are stationary in levels. In addition to the time

[7] The results for the ADF and KPSS tests are available upon request.

series properties of the variables, an outlier analysis was performed rejecting the existence of extreme values[8].

The model specification is defined in the following equations:

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 RDA_t + \alpha_3 WD_t + \alpha_4 UpR_t + \varepsilon_t \qquad (6)$$

$$ASC_t = \alpha_0 + \alpha_1 ASC_{t-1} + \alpha_2 RDA_t + \alpha_3 RDA_t^2 + \alpha_4 WD_t + \alpha_5 UpR_t + \varepsilon_t \qquad (7)$$

The main difference between Eq. (6) and (7) is the inclusion of a quadratic component in the econometric model to test for a linear or polynomial relationship between the variables. In the least squares estimation of this dynamic model, it is evident that the unobserved initial values of the dynamic process induce a bias. Instrumental variable methods are able to produce consistent estimators for dynamic data models that are independent of the initial conditions. These estimators are based on the idea that lagged (or lagged differences of) regressors are correlated with the regressor included but are uncorrelated with the innovations. Thus, valid instruments are available from within the model and these can be used to estimate the parameters of interest employing instrumental variable methods. In this paper, the construction of instruments is done using values of the dependent variable lagged two periods and the lag of the exogenous variables, which are all independent of ε_t, to perform estimations using the instrumental variable regression method.

4. RESULTS AND DISCUSSION

To test the hypothesis of a differentiated impact of real demand adjustments on the costs of the system adjustment services resulting from the liberalisation we performed four sets of estimations corresponding to the two equations and time periods explained above. The estimation results are presented in Table 4, where the first two columns correspond to the linear model estimates (Eq. (6)) before and after the policy change. The first period covers the 12-month period before the policy change (from 1 July 2008 to 30 June 2009) and the second period covers the 12-month period after the policy became effective (from 1 July 2009 to 30 June 2010). Analogously, the results in columns (3) and (4) correspond to the quadratic model estimates (Eq. (7)) before and after the policy change.

Overall, the results show that, as a consequence of liberalisation, the system's ASCs increased. In general, the constant is higher after the policy change than before; hence, regardless of the impact of the RDAs, the weekly seasonality and the type of energy regulation, the ASCs increased after liberalisation. These results are indicative of the general impact but they are not specifically what we are interested in, as our objective is to determine if the ASCs fluctuate as a consequence of the change in the relation between the costs and the

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

real demand adjustments attributable to the new role played by the DSO following liberalisation.

Table 4: Impacts on the system adjustment service costs before and after liberalisation

	Linear		*Quadratic*	
	(Before) ***(1)***	***(After)*** ***(2)***	***(Before)*** ***(3)***	***(After)*** ***(4)***
RDA	2.766***	6.200***	2.259***	1.875*
	(0.339)	(0.445)	(0.694)	(1.090)
RDA^2			4.901	34.04***
			(5.851)	(7.814)
WD	0.0603***	0.0792**	0.0609***	0.0848***
	(0.0181)	(0.0321)	(0.0181)	(0.0321)
UpR	0.0848***	0.155***	0.0843***	0.153***
	(0.0167)	(0.0298)	(0.0167)	(0.0298)
L.ar	0.871***	0.851***	0.871***	0.848***
	(0.00569)	(0.00639)	(0.00570)	(0.00640)
Constant	0.161***	0.0962**	0.167***	0.186***
	(0.0224)	(0.0389)	(0.0239)	(0.0438)
Observations	8,759	8,759	8,759	8,759
R-squared	0.786	0.746	0.783	0.741
dydx (RDA & RDA^2)			2.5767	4.0833***

Robust standard errors in parentheses *** p<0.01, ** p<0.05, * p<0.1

Based on the graphical representation presented in section 3 above, we hypothesised that the nature of the relationship between RDAs and ASCs differed before and after the implementation of the policy, and we estimated linear and quadratic functions to test this. The results confirm that, while before liberalisation the relationship between the two variables had a linear form (the coefficient of RDA^2 in column (3) is not significant), after the policy change it takes a quadratic form (the coefficient of RDA^2 in column (4) is significant). These results are of particular relevance since they imply that following liberalisation the impact of demand adjustments on the ASCs have become increasingly stronger.

The short-run marginal effects of these regression results provide additional insights into the magnitude of the implications of the policy change (see Table 5). Before liberalisation each MWh of RDA generated an adjustment services cost of 2.76 €/MWh; after liberalisation the same demand adjustment generates an ASC of 4.08 €/MWh. This means that the immediate direct effect of the policy change is an increase of 47.8% (see first line of Table 6). However, to place these figures in the right perspective, we need to take into account that the ASCs differ in both periods; hence, we divided the previous effects by the average value of the ASCs. The results indicate that on average each MWh of RDA generated a 12.7% increase in ASCs before and 26.90% after liberalisation (see second line of Table 5).

Table 5: Short-Run Marginal Effects

	Before	After	Diff (B vs. A)
dy/dx (€/MWh)	2.76	4.08	47.80%
(dy/dx)/$\overline{y}$	12.70%	26.90%	14.20%

The difference in the marginal effects from each MWh of RDA on the average ASCs can be used to measure the monetary cost of the policy. By multiplying this difference in the marginal effects (14.20%) and the average ASCs after the regulatory change, we find that the additional cost is 0.348 € per MWh consumed. With this information, and taking into account that total consumption in the 12-month period following the policy change (July 2009 to June 2010) was 257 TWh, the impact of liberalisation on the adjustment services represented an overall cost of 90 million € /year.

As for the dynamic component, our results indicate that the ASCs depend heavily on their value in the previous hour. Hence, depending on the model and period considered, a 1€/MWh increase in the level of ASCs in the previous hour increases the costs by between 0.84 and 0.87 €/MWh. The inertial behaviour of the system adjustment costs, related to the criteria followed by the SO to assess control reserves, seems to account for these outcomes.

Finally, our results for the additional control variables are in line with expectations. First, we find that the effect of the positive energy market balance on the adjustment costs is always higher than that of the negative balance. These results are as expected for this control variable, since it captures the fact that adjustment services are more costly when the system requires upward regulation than when it requires downward regulation. The costs of balancing power are heavily dependent on the kind of generation technology used for regulation (Holttinen, 2005, Holttinen et al., 2011), with hydropower being the cheapest option and gas turbines the most expensive, as well as the overall situation of the system. From a cost perspective, it is not the same to be in a long system position requiring downward regulation energy, as it is to be in a short system position requiring upward regulation energy. The explanation for this price differential lies in the fact that to provide upward regulation, the generation resources must set some generation capacity aside, which could otherwise have been traded in the power markets. The provision of downward regulation merely requires that the generation unit be able to ramp down (Van der Veen et al., 2010). And second, the variable capturing the seasonality of electricity demand across the week is positive and significant in all regressions. This positive effect seems to be related to the amount of generation connected to the system that is capable of providing flexible services to the system. Over the weekend, a similar pattern of VRES generation to that recorded on a working day may result in a low net demand. Under such a scenario, conventional generation could increase its participation in the adjustment services markets in order to complete the generation program and in this way avoid shutting down only to have to start up a few hours later.

5. CONCLUSIONS AND POLICY IMPLICATIONS

Electricity markets across Europe had undergone an institutional transition. To enhance economic efficiency and improve services to the consumer, European electricity markets had been liberalised, leading to the introduction of competition and opening of the markets. In this process, the current role of some agents, such as DSOs has changed being its role strongly influenced by the unbundling measures introduced in the regulatory framework. In this regard, the Second Electricity Directive implied a change in the duties and responsibilities of Spanish DSOs.

When discussing the best way to achieve competitive and integrated European electricity retail markets, this change has to be considered in general terms as positive and DSOs should be seen as key agents in the liberalisation process (Eurelectric, 2010). For this reason, this paper has not sought to question the decisions taken within the framework of the EU's directives. Indeed, DSOs have been shown to be instrumental in the roll-out of smart grids and smart meters, and to have played a leading role in aggregation, demand response and energy efficiency, among other relevant aspects. The drawback analysed in this paper is not that distribution companies are not suppliers of energy in the retail market, but rather that the regulatory framework should have anticipated the economic impact associated with the change of scheme by establishing corrective measures.

Under the new liberalised scenario, energy suppliers have to estimate demand in order to make sure that sufficient supply is available on different timescales. Calculating both the total electricity demand and the specific electricity demand for different uses based on limited metered data constitutes a common problem across Europe, not being Spain an exception. Under a similar methodological approach to estimate the electricity demand, differences arise when considering the technical aspects involved in the construction of the different load profiles and losses coefficients trying all these methods to provide the most representative patterns for electricity usages for the different segments of liberalised customers.

In terms of policy implications, when analysing this kind of policy changes, under our opinion, the most relevant question to be addressed is the relevance of the regulatory framework and its ability to anticipate the effects that stem from these changes being able to provide satisfactory answers. The success of this kind of transformation process is what underpins a smart regulation; that is, one that is capable of providing solutions to unexpected outcomes during the process. Our paper has sought to contribute to existing knowledge regarding the economic effects of liberalisation in the power system by examining a natural experiment associated with the regulatory changes introduced in Spain in 2009. Since then, regulated supply by DSOs has disappeared. This positive change in terms of retail market competition, as we have shown in this paper, had unexpected collateral effects in terms of the system's balancing requirements.

In this sense, the policy change introduced in July 2009 regarding the role of the DSOs is relevant for the evolution in adjustment costs in Spain. From this date, the suppliers are the only ones responsible to estimate demand in order to make sure that sufficient supply is available on different timescales. Hourly consumption for all customers on a daily basis is estimated based on load profiles and loss coefficients determined ex-ante. To the extent that electricity balance, resulting from the difference between the measured losses in transmission and distribution and the standard losses used in the balancing procedure of the system as a whole, requires additional adjustment services, the policy directly increased the energy requirements associated with the electricity market balance. In this sense, this paper provides an economic estimation of the economic impacts of this policy on adjustment services costs and, hence, on final electricity prices.

Although in 2009 the combined day-ahead and intraday market prices accounted for 89% of the final price, whilst the cost resulting from the management of system adjustment services accounted for just 6.3%, the impact of these latter costs on the final price of energy has grown substantially. In the first year of policy change, the amount of energy managed in the system adjustment services markets was 23,918 GWh, 34.9% higher than in the previous year, a clear indication that something was amiss in the adjustment services markets. Isolating the economic effects attributable to the policy change, we find that the extra cost in relative terms was around 0.348 € per MWh consumed. Thus, in the first year alone, the effects of liberalisation via the real demand adjustment on the adjustment services represented an overall cost of 90 million €.

This increase in terms of the costs linked to adjustment services is relevant both from a macro and microeconomic point of view. At a time when energy prices are raising concerns about the impact on economic competitiveness, it becomes increasingly relevant from a macroeconomic perspective to identify any source of distortion affecting final electricity prices. At the same time, from a microeconomic perspective it should be stressed that any unexpected increase in the adjustment service costs has a marked impact on the results of independent electricity retailers. While the price risk associated with unexpected variations in the day-ahead market price could be covered on the futures markets, unforeseen variations in the cost of adjustment services could not be covered. Therefore, an unexpected increase in adjustment service costs has a direct impact on the business results of retailers – especially on those of new entrants. This highlights the importance of the analysis undertaken in this paper. An in-depth understanding of the factors that account for the evolution of operational costs will ultimately be helpful when making improvements to the regulatory framework to facilitate the success of retail market competition, specially in a context where the flexibility requirements have increased over the last few years. Although this study is applied to Spain the results are of general interest to other countries mainly because the more common regulatory design within the EU on liberalisation promotion is applied. The Spanish experience provides useful insight to other countries where the process of liberalisation of the retail market is at early stages.

From a short- and medium-term perspective, improvements have to be introduced. Smart metering is a highly promising technology, which will greatly empower electricity customers to become active managers of their consumption. At the same time, smart meters should result in the optimisation of the overall electricity distribution infrastructure. The expected large-scale deployment of smart meters in Spain will enable both suppliers and DSOs to use more accurate individual consumption data (load profiles) in their processes. Nevertheless, in the short-term, measures such as those introduced in June 2014, aimed at establishing standard coefficients of losses and load profiles that take into account different time and seasonal patterns should facilitate a reduction in associated costs. Since the initiation of liberalisation, costs of at least 450 million € have been borne by final consumers. The transformation would probably have been faster if instead of socialising through the final price of electricity, the extra cost had been assigned to a specific agent (e.g., the last resort or liberalised supplier). During this five-year period, no price signal was given to the suppliers – or to the regulator who had ultimate responsibility for determining the standard coefficients of losses – because of the greater requirements of flexibility expected in the system.

Behind every major change, such as the transformation ushered in by the liberalisation of the electricity market, it is critical that the details of the process be carefully examined. The challenges faced in attaining the goals set are largely determined by regulatory issues or, more specifically, by micro-regulations and their implementation. It is, obviously, vital to assess the economic consequences for the whole system of any policy change, especially if the intention of a smart regulation is to benefit all consumers. In the context of growing concern about competiveness, the wise use of available resources and the employment of smart market policy tools are essential if we are to benefit fully from sustainable and reliable power systems.

Although this study is applied to Spain the results are of general interest to other countries mainly because the most common regulatory design within the EU on liberalisation promotion is applied. The Spanish experience provides useful insight to other countries where the process of liberalisation of the retail market is at early stages.

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Appendix: Technical aspects underpinning the energy market balance

In a liberalised framework, suppliers buy the total amount of energy required to fulfil the expected demand of their customers on the electricity markets. Suppliers determine hourly electricity demand using different forecast methods and techniques. In order to avoid the extra-costs associated with higher prices on the different markets after day-ahead market gate closure, the supplier seeks to achieve the best possible demand estimation. In this way, suppliers aim at covering their demand on the day-ahead market without their having to make adjustments on posterior markets, which typically are more expensive.

As the majority of customers are connected at low voltage (LV) level (< 1 kV), the suppliers' demand has to take into account total network electricity losses. For each hour and for each voltage level, suppliers have to include total estimated losses[9] in their bids for the day-ahead market. According to the methodology established by Spain's electricity legislation, energy losses are allocated to each consumer taking into consideration their consumption characteristics. More specifically, the allocation of losses is the result of multiplying the end-use meter data of each consumer by a standard loss coefficient (transmission and distribution loss factor). Therefore, the expected hourly electricity demand of each supplier, measured at the power station busbars, is:

$$E_j^h = \sum_{i=1}^{n} (E_i^h \cdot (1 + K_i^h)) \qquad (A1)$$

being:

E_j^h: Expected hourly electricity demand of each supplier (j), with $h = 1,...,24$.

E_i^h: Expected hourly electricity demand of each category of consumer differentiated by voltage level (i)[10].

K_i^h: Hourly standard losses coefficient differentiated by voltage level (i), with $i = 1,...,n$.

Standard loss coefficients (K_i^h) are used to calculate the standard network losses of the distribution companies, which are charged to consumers through full-service and access tariffs.

According to Eq. (A1), the energy metered at each connection point between the transmission and distribution grids has to be increased by the corresponding percentage of losses. For those consumers – mainly domestic and residential – that are not metered on a time interval

[9] Total losses are determined as the difference between the energy metered at transmission and distribution network entry points and the energy metered at distribution network exit points (energy billed to customers). Total losses can be divided (Sáenz et al., 2011) into two different groups depending on their nature: technical losses caused by current flowing though the network and non-technical losses mainly caused by theft, fraud or administrative errors among other explanatory factors.

[10] In Spain, coefficients are differentiated according to the voltage level (n) of the network to which the customer is connected: high voltage (HV) network (36-220 kV), medium voltage (MV) network (1-36 kV) and low voltage (LV) network (<1kV). In this regards, the expected hourly demand (E_i^h) results from the load aggregation corresponding to customers connected to the n different voltage levels.

basis, electricity demand is calculated using load profiles. In general, adopting different approaches, load profiles seek to characterize domestic electricity patterns of use on an intra-daily, diurnal and seasonal basis as a function of consumer characteristics. In the case of Spain, static profiles are derived from consumption data for each time interval considered, as collected from existing historic demand records for a sufficiently large sample of customers. With this information, which takes into account factors that might affect consumption and which might vary from day to day as well as from year to year (variations in the weather, holiday periods, etc.), domestic standard load profiles are constructed aimed at determining aggregate electricity consumption for all households without hourly metering across a 24-hour period. Profiling enables an electricity supplier to calculate the electricity consumption for every pricing period on the market (hourly time intervals in the case of Spain) for its customers that do not have a time interval meter installed.

Load profile-based metering implies that the expected hourly electricity demand of each category of consumer (E_i^h) is calculated as:

$$E_i^h = \sum_{i=1}^{n} (E_i^d \cdot L_i^h) \qquad (A2)$$

being:

E_i^d: Expected daily electricity demand.

L_i^h: Average load profile of a class of customers (i) over a given hour (h).

In short, the expected hourly electricity demand (E_j^h), based upon estimates using standard loss coefficients (K_i^h) and load profiles (L_i^h), constitutes the basis for the supplier to purchase from the wholesale market the electricity required by its customers. However, the use of both adjustment parameters has certain implications for the energy finally contracted. As the annual losses have been determined ex ante using standard loss coefficients, their value will not coincide with the real value of annual technical losses in the network. Likewise, the use of load profiling to determine a consumer's electricity consumption inherently introduces discrepancies between estimated and real load (E_r^h), therefore:

$$E_s^h \neq E_r^h \qquad (A3)$$

being:

E_s^h: Expected total hourly electricity demand obtained as the sum of the expected hourly electricity demand of each supplier (j):

$$E_s^h = \sum_{j=1}^{J} E_j^h \qquad (A4)$$

E_r^h: Real hourly electricity demand

As discussed above, given that the energy finally dispatched to meet the customers' energy requirements, is not necessarily the same as that initially expected by the suppliers, a positive or negative energy difference arises, for which a balancing process is required. The electricity market balance requires additional adjustment services to ensure that generation and demand are in permanent equilibrium. This duty lies primarily with the system operator (SO). As the entity with overall responsibility for short-term system operation, the SO normally handles the balance-settlement and generation-load reconciliation process via processes of adjustment services management.

The post-liberalisation model of energy imbalance described above differs from the pre-liberalisation model. Under the pre-liberalisation system, the energy imbalance was resolved by the DSOs permanently matching electricity demand forecasts with the energy actually dispatched. Here, the electricity supply (E_s^h) was provided at a regulated tariff (E_{reg}^h) through a distribution company or at a market price (E_{lib}^h) through a supplier. The energy demanded in the wholesale market was equivalent to consumption measured at the power station busbars thanks to DSOs who adjusted their demand in the power exchange in an attempt at minimising the energy market balance.

In this pre-liberalisation scheme, where the liberalised and regulated supply coexisted, demand from distribution companies (E_{reg}^h) was determined at the border point in the distribution grid – affected by the corresponding loss profiles and standard coefficients – after subtracting the energy belonging to the liberalised customers (E_{lib}^h) connected to the distribution area. In the post-liberalisation model, with the disappearance of the distributor as a supplier of electricity, the previous scheme was no longer valid. The estimated hourly electricity demand is calculated as it was previously for the consumption of the liberalised customers but distributors make no adjustments. This means that the hourly energy demand on the market estimated by suppliers does not coincide with the electricity finally dispatched. The SO therefore uses ancillary services to correct this difference. The pre- and post-liberalisation loss adjustment schemes are summarised in Table A.1.

Table A.1: Main implications in terms of electricity losses

	Before July 2009	**After July 2009**
Estimated versus real load	$E_s^h = E_r^h$	$E_s^h \neq E_r^h$
Losses adjustment process	$E_{reg}^h = E_s^h - E_{lib}^h$	$E_r^h - E_s^h = EMB$ *EMB is adjusted in the balancing markets*

Under a similar approach aimed at reducing system costs through the use of standard coefficient of losses that better capture time and seasonal patterns, across Europe the differences from system to system remain in the specificities. Technical aspects related with the methods for establishing the difference between estimated and actual consumption and the price at which this difference is settled constitute the main difference from system to system. According to Spanish legislation, the day-ahead price is used to clear the differences between the system's real losses and those resulting from the application of a standard coefficient of losses.

Coordinated Scheduling of Wind-Thermal Gencos in Day-Ahead Markets

R. Laia[1,2], H.M.I. Pousinho[1], R. Melício[1,2], V.M.F. Mendes[1,3]

[1]*IDMEC/LAETA, Instituto Superior Técnico, Universidade de Lisboa, Lisbon, Portugal*
[2]*Departamento de Física, Escola de Ciências e Tecnologia, Universidade de Évora, Portugal*
[3]*Instituto Superior de Engenharia de Lisboa, Lisbon, Portugal; ruimelicio@gmail.com*

ABSTRACT

This paper presents a stochastic mixed-integer linear programming approach for solving the self-scheduling problem of a price-taker thermal and wind power producer taking part in a pool-based electricity market. Uncertainty on electricity price and wind power is considered through a set of scenarios. Thermal units are modeled by variable costs, start-up costs and technical operating constraints, such as: ramp up/down limits and minimum up/down time limits. An efficient mixed-integer linear program is presented to develop the offering strategies of the coordinated production of thermal and wind energy generation, aiming to maximize the expected profit. A case study with data from the Iberian Electricity Market is presented and results are discussed to show the effectiveness of the proposed approach.

KEYWORDS: Mixed-integer linear programming; stochastic optimization; wind-thermal coordination; offering strategies

1 INTRODUCTION

The negative environmental impact of fossil fuel burning and the desire to achieve energy supply sustainability promote exploitation of renewable sources. Mechanisms and policies provide subsidy and incentive for renewable energy conversion into electric energy [1], for instance, wind power conversion. But as the wind power technology matures and reaches breakeven costs, subsidy is due to be less significant and wind power conversion has to face the electricity markets for better profit [2]. Also, the incentives for wind power exploitation are feasible for modest penetration levels but will become flawed as wind power penetration increases [3]. EU in 2014 has of all new renewable installations a 43.7% based on wind power and is the seventh year running that over 55% of all additional power capacity is form renewable energy [4]. The growing worldwide usage of renewable energy is a fact, but electricity supply is still significantly dependent on fossil fuel burning, for instance, statistics for electricity supply in 2012 accounts that the usage of fossil fuel burning is more than 60% [5].

Deregulation of electricity market imposes that a generation company (GENCO) has to face competition to obtain the economic revenue. Periodic nodal variations of electricity prices [6] have to be taken into consideration. The wind power producer (WPP) has to address wind power and electricity price uncertainties to decide for realistic bids, because cost is owed either in case of excessive or moderate bids due to the fact that other power producers must reduce or increase production to fill the so-called deviation [7]. While the thermal power producer has to address only electricity price uncertainty.

2 STATE OF THE ART

Thermal energy conversion into electric energy has a significant state of art on optimization methods to solve the unit commitment problem (UC), ranging from the old priorities list method to the classical mathematical programming methods until the more recently reported artificial intelligence methods [8]. The priority list method is easy implemented and requires a small processing time, but does not ensure a convenient solution near the global optimal one [9]. Within the classical methods are included dynamic programming and Lagrangian relaxation-based methods [10]. The dynamic programming method is a flexible one but has a limitation known by the "curse of dimensionality". The Lagrangian relaxation can overcome the previous limitation, but does not necessarily lead to a feasible solution, implying further processing for satisfying the violated constraints in order to find a feasible solution, which does not ensure optimal solution. The mixed integer linear programming (MILP) method has been applied with success for solving UC problem [11]. MILP is one of the most successful explored methods for scheduling activities because of flexibility and extensive modeling capability [12]. Although, artificial intelligence methods based on artificial neural networks, genetic algorithms, evolutionary algorithms and simulating annealing have been applied, the major limitation of the artificial intelligence methods concerning with the possibility to obtain a solution near the global optimum one is a disadvantage. So, classical methods are the main methods in use as long as the functions describing the mathematical model have conveniently smoothness.

Deregulated market and variability of the source of wind power impose uncertainties to WPP. These uncertainties have to be conveniently considered, i.e., processed into the variables of the problems [13] to be addressed by a WPP in order to know how much to produce and the price for bidding.

A WPP in a competitive environment can benefit without depending on third-parties from: a coordination of wind power production with energy storage technology [14]; a financial options as a tool for WPP to hedge against wind power uncertainty [15]; a stochastic model intended to produce optimal offer strategies for WPP participating in an electricity market [16]. The stochastic model is a formulation explicitly taking into account the uncertainties faced by the scheduling activities of a WPP [17], using uncertain measures and multiple scenarios built by computer applications for wind power and electricity price forecasts [18]. The participation in bilateral contracts is suitable for thermal power producers in order to hedge against price uncertainty [19].

3 PROBLEM FORMULATION

3.1 Day-Ahead Market

The uncertainties about the availability of wind power may result in differences between the energy traded with a WPP and the actual quantity of energy delivered by the WPP. The revenue R_t of the GENCO for hour t is stated as:

$$R_t = \lambda_t^D P_t^{offer} + I_t \tag{1}$$

In (1), P_t^{offer} is the power at the close of the day-ahead market accepted to be traded and I_t is the imbalance income resulting from the balancing penalty of not acting in accordance with the accepted trade. The total deviation for hour t is stated as:

$$\Delta_t = P_t^{act} - P_t^{offer} \tag{2}$$

where P_t^{act} is the actual power for hour t.

In (2), a positive deviation means the actual power traded is higher than the traded in the day-ahead market and a negative deviation means the power is lower than the traded. Let λ_t^+ be the price paid for excess of production and λ_t^- the price to be charged for deficit of production. Consider the price ratios given by the equalities stated as:

$$r_t^+ = \frac{\lambda_t^+}{\lambda_t^D}, r_t^+ \le 1 \quad \text{and} \quad r_t^- = \frac{\lambda_t^-}{\lambda_t^D}, r_t^- \ge 1 \tag{3}$$

In (3), the inequalities at the right of the equalities mean, respectively, that the positive deviation never has a higher price of penalization and the negative one never has a lower price of penalization in comparison with the value of the closing price.

3.2 Wind-Thermal Gencos

The operating cost, $F_{\omega i t}$, for a thermal unit can is stated as:

$$F_{\omega i t} = A_i\, u_{\omega i t} + d_{\omega i t} + b_{\omega i t} + C_i\, z_{\omega i t} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{4}$$

In (4), the operating cost of a unit is the sum of: the fixed production cost, A_i, a fixed associated with the unit state of operation; the added variable cost, $d_{\omega i t}$, part of this cost is associated with the amount of fossil fuel consumed by the unit; and the start-up and shut-down costs, respectively, $b_{\omega i t}$, and C_i, of the unit. The last three costs are in general described by nonlinear function and worse than that some of the functions are non- convex and non-differentiable functions, but some kind of smoothness is expected and required to use MILP, for instance, as being sub-differentiable functions.

The functions used to quantify the variable, the start-up and shut-down costs of units in (4) are considered to be such that is possible to approximate those function by a piecewise linear or step functions. The variable cost, $d_{\omega i t}$ is stated as:

$$d_{\omega i t} = \sum_{l=1}^{L} F_i^{\,l}\, \delta_{\omega i t}^{l} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{5}$$

$$p_{\omega i t} = p_i^{\min} u_{\omega i t} + \sum_{l=1}^{L} \delta_{\omega i t}^{l} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{6}$$

$$(T_i^{\,1} - p_i^{\min})\, t_{\omega i t}^{1} \le \delta_{\omega i t}^{1} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{7}$$

$$\delta_{\omega i t}^{1} \le (T_i^{\,1} - p_i^{\min})\, u_{\omega i t} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{8}$$

$$(T_i^{\,l} - T_i^{\,l-1})\, t_{\omega i t}^{l} \le \delta_{\omega i t}^{l} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t,\quad \forall\, l = 2,\dots,L-1 \tag{9}$$

$$\delta_{\omega i t}^{l} \le (T_i^{\,l} - T_i^{\,l-1})\, t_{\omega i t}^{l-1} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t,\quad \forall\, l = 2,\dots,L-1 \tag{10}$$

$$0 \le \delta_{\omega i t}^{L} \le (p_i^{\max} - T_{\omega i t}^{L-1})\, t_{\omega i t}^{L-1} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{11}$$

In (5), the variable cost function is given by the sum of the product of the slope of each segment, $F_i^{\,l}$, by the segment power $\delta_{\omega i t}^{l}$. In (6), the power of the unit is given by the minimum power generation plus the sum of the segment powers associated with each segment. The binary variable $u_{\omega i t}$ ensures that the power generation is equal to 0 if the unit is in the state offline. In (7), if the binary variable $t_{\omega i t}^{l}$ has a null value, then the segment power $\delta_{\omega i t}^{1}$ can be lower than the segment 1 maximum power; otherwise and in conjunction with (8), if the unit is in the state on, then $\delta_{\omega i t}^{1}$ is equal to the segment 1 maximum power. In (9), from the second segment to the second last one, if the binary variable $t_{\omega i t}^{l}$ has a null value, then the segment power $\delta_{\omega i t}^{l}$ can be lower than the segment l maximum power; otherwise and in conjunction with (10), if the unit is in the state on, then $\delta_{\omega i t}^{l}$ is equal to the segment l maximum power. In (11), the segment power must be between zero and the last segment maximum power.

The nonlinear nature of the start-up costs function, $b_{\omega i t}$, is normally considered to be described by an exponential function. This exponential function is approximated by a piecewise linear formulation as in [2] stated as:

$$b_{\omega i t} \geq K_i^{\beta}\left(u_{\omega i t} - \sum_{r=1}^{\beta} u_{\omega i t-r}\right) \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{12}$$

In (12), the second term models the lost of thermal, i.e., if the unit is a case of being in the state online at hour t and has been in the state offline in the β preceding hours, the expression in parentheses is equal to 1. So, in such a case a start-up cost is incurred for the thermal energy that are not accountable for added value in a sense of that energy has not been converted into electric energy. The maximum number for β is given by the number of hours need to cool down, i.e., completely lose all thermal energy. So, for every hour at cooling and until total cooling one inequality like (12) is considered.

The units have to perform in accordance with technical constraints that limit the power between successive hours stated as:

$$p_i^{\min} u_{\omega i t} \leq p_{\omega i t} \leq p_{\omega i t}^{\max} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{13}$$

$$p_{\omega i t}^{\max} \leq p_i^{\max}(u_{\omega i t} - z_{\omega i t+1}) + SD\, z_{\omega i t+1} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{14}$$

$$p_{\omega i t}^{\max} \leq p_{\omega i\, t-1}^{\max} + RU\, u_{\omega i t-1} + SU\, y_{\omega i t} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{15}$$

$$p_{\omega i t-1} - p_{\omega i t} \leq RD\, u_{\omega i t} + SD\, z_{\omega i t} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, t \tag{16}$$

In (13) and (14), the upper bound of $p_{\omega i t}^{\max}$ is set, which is the maximum available power of the unit. This variable considers: unit's actual capacity, start-up/shut-down ramp rate limits, and ramp-up limit. In (16), the ramps-down and shut-down ramp rate limits are considered. In (14)–(16), the relation between the start-up and shut-down variables of the unit are given, using binary variables for describing the states and data parameters for ramp-down, shut-down and ramp-up rate limits.

The minimum down time constraint is imposed by a formulation stated as:

$$\sum_{t=1}^{J_i} u_{\omega i t} = 0 \quad \forall\, \omega,\quad \forall\, i \tag{17}$$

$$\sum_{t=k}^{k+DT_i-1} (1 - u_{\omega i t}) \geq DT_i z_{\omega i t} \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, k = J_i + 1 \ldots T - DT_i + 1 \tag{18}$$

$$\sum_{t=k}^{T} (1 - u_{\omega i t} - z_{\omega i t}) \geq 0 \quad \forall\, \omega,\quad \forall\, i,\quad \forall\, k = T - DT_i + 2 \ldots T \tag{19}$$

$$J_i = \min\{\, T, (DT_i - s_{\omega i 0})(1 - u_{\omega i 0})\}$$

In (17), if the minimum down time has not been achieved, then the unit remains offline at hour 0. In (18), the minimum down time will be satisfied for all the possible sets of consecutive hours of size DT_i. In (19), the minimum down time will be satisfied for the last $DT_i - 1$ hours.

The minimum up time constraint is also imposed by formulation stated as:

$$\sum_{t=1}^{N_i}(1-u_{\omega i t})=0 \quad \forall\,\omega,\quad \forall\, i \tag{20}$$

$$\sum_{t=k}^{k+UT_i-1}u_{\omega i t} \geq UT_i\, y_{\omega i t} \quad \forall\,\omega,\quad \forall\, i,\quad \forall\, k=N_i+1\,...\,T-UT_i+1 \tag{21}$$

$$\sum_{t=k}^{T}(u_{\omega i t}-z_{\omega i t}) \geq 0 \quad \forall\,\omega,\quad \forall\, i,\quad \forall\, k=T-UT_i+2\,...\,T \tag{22}$$

$$N_i=\min\{\,T,(UT_i-U_{\omega i 0})\,u_{\omega i 0}\}$$

In (20), if the minimum up time has not been achieved, then the unit remains offline at hour 0. In (21), the minimum up time will be satisfied for all the possible sets of consecutive hours of size UT_i. In (22), the minimum up time will be satisfied for the last UT_i-1 hours.

The relation between the binary variables to identify start-up, shutdown and forbidden operating zones is stated as:

$$y_{\omega i t}-z_{\omega i t}=u_{\omega i t}-u_{\omega i t-1} \quad \forall\,\omega,\quad \forall\, i,\quad \forall\, t \tag{23}$$

$$y_{\omega i t}+z_{\omega i t} \leq 1 \quad \forall\,\omega,\quad \forall\, i,\quad \forall\, t \tag{24}$$

$$y_{\omega i t}+z_{\omega i t} \leq 1 \quad \forall\,\omega,\quad \forall\, i,\quad \forall\, t \tag{25}$$

The total power generated by the thermal units is stated as:

$$\sum_{i=1}^{I}p_{\omega i t}=p^{g}_{\omega t}+\sum_{m=1}^{M}p^{bc}_{m t} \quad \forall\omega,\forall i,\forall t\,,\forall m \tag{26}$$

In (26), $p^{g}_{\omega t}$ is the actual power generated by the thermal units for the day-ahead market and $p^{bc}_{m t}$ is the power contracted in each bilateral contract m.

3.3 Objective Function

The offer submitted by the GENCO is the sum of the power offered from the thermal units and the power offered from the wind farm $p^{D}_{\omega t}$. The offer is stated as:

$$p^{offer}_{\omega t}=p^{th}_{\omega t}+p^{D}_{\omega t} \quad \forall\omega,\ \forall t \tag{27}$$

The actual power generated by the GENCO is the sum of the power generated by the thermal units and the power generated by the wind farm. The actual power is stated as:

$$p^{act}_{\omega t}=p^{g}_{\omega t}+p^{d}_{\omega t} \quad \forall\omega,\ \forall t \tag{28}$$

In (28), $p^{g}_{\omega t}$ is the actual power generated by the thermal units and $p^{d}_{\omega t}$ is the actual power generated by the wind farm for each scenario ω.

Consequently, the expected revenue of the GENCO is stated as:

$$\sum_{\omega=1}^{N_\Omega}\sum_{t=1}^{N_T}\pi_\omega\left[\left(\lambda^D_{\omega t}P^{offer}_{\omega t}+\lambda^D_{\omega t}r^+_{\omega t}\Delta^+_{\omega t}-\lambda^D_{\omega t}r^-_{\omega t}\Delta^-_{\omega t}\right)-\sum_{i=1}^{I}F_{\omega i t}\right] \quad \forall\omega,\ \forall t \tag{29}$$

Subject to:

$$0\le p^{offer}_{\omega t}\le p^{M}_{\omega t} \quad \forall\omega,\ \forall t \tag{30}$$

$$\Delta_{t\omega}=\left(p^{act}_{\omega t}-p^{offer}_{\omega t}\right) \quad \forall\omega,\ \forall t \tag{31}$$

$$\Delta_{t\omega}=\Delta^+_{t\omega}-\Delta^-_{t\omega} \quad \forall\omega,\ \forall t \tag{32}$$

$$0\le\Delta^+_{t\omega}\le P_{t\omega}d_t \quad \forall\omega,\ \forall t \tag{33}$$

In (29), the revenue from the bilateral contracts are not included, however the cost of thermal production includes the total power generated by the thermal units stated in (26).

In (30), $p^{M}_{\omega t}$ is maximum available power, limited by the sum of the installed capacity in the wind farm, $p^{E\max}$, with the maximum thermal production stated as:

$$p^{M}_{\omega t}=\sum_{i=1}^{I}p^{\max}_{\omega i t}+p^{E\max} \quad \forall\omega,\ \forall t \tag{34}$$

Some system operators require non-decreasing offers to be submitted by the GENCO. Non-decreasing offers is considered by a constraint stated as:

$$(p^{offer}_{\omega t}-p^{offer}_{\omega' t})(\lambda^D_{\omega t}-\lambda^D_{\omega' t})\ge 0 \quad \forall\ \omega,\omega',\quad \forall\ t \tag{35}$$

In (35), if the increment in price in two successive hours is not null, then the increment in offers in the two successive hours has two be of the same sign of the increment in price or a null value.

4 CASE STUDY

The proposed stochastic MILP approach is illustrated by a case study of a GENCO with a WTPP, having 8 units with a total installed capacity of 1440 MW, the data is in [20]. Data from the Iberian electricity market for 10 days of June 2014 [19] are used for the energy prices and the energy produced from wind farm. This data is shown in Fig. 1.

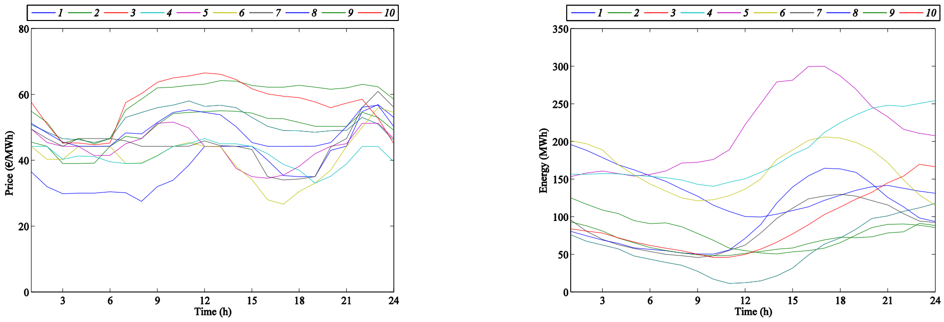

Fig 1. Iberian market June 2014 (ten days); left: prices, right: energy.

The nondecreasing offer is required. The energy produced is obtained using the total energy produced from wind scaled to the installed capacity in the wind farm, 360 MW. The expected results with and without coordination in the absence of bilateral contracts are shown in Table 1.

Table 1. Results with and without coordination

Case	Expected profit
Wind uncoordinated (€)	119 200
Thermal uncoordinated (€)	516 848
Coordinated Wind and thermal (€)	642 326
Gain (%)	0,99

The non-decreasing energy offer for the coordinated and uncoordinated approach is shown in Fig. 2 for two different hours.

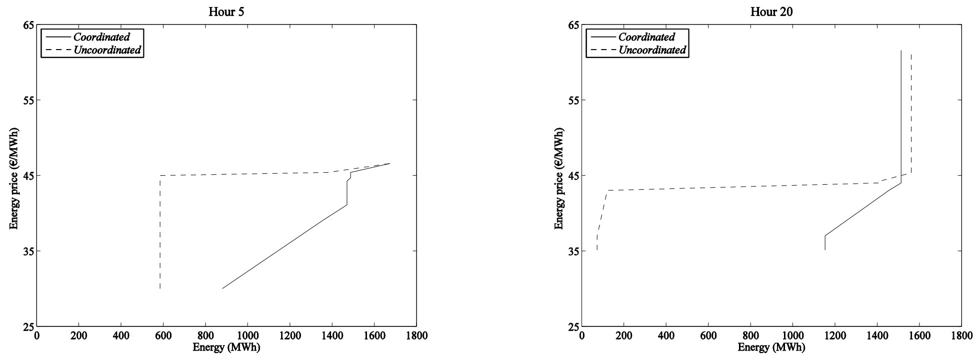

Fig 2. Bidding energy offers.

In Fig. 2, the coordination allows for a minimum value of power offered higher than the one offered without coordination and allows for a lower price of the offering, which is a potential benefit to into operation.

For the bilateral contracts 10 levels of energy contracted are simulated for the same market conditions described above. The power contracted in the bilateral contracts and the impact of bilateral contracts treated as a deterministic problem in the energy offered in the day-ahead market is shown in Fig. 3, where the energies are the average of the ten market scenarios for each level of energy from the bilateral contract.

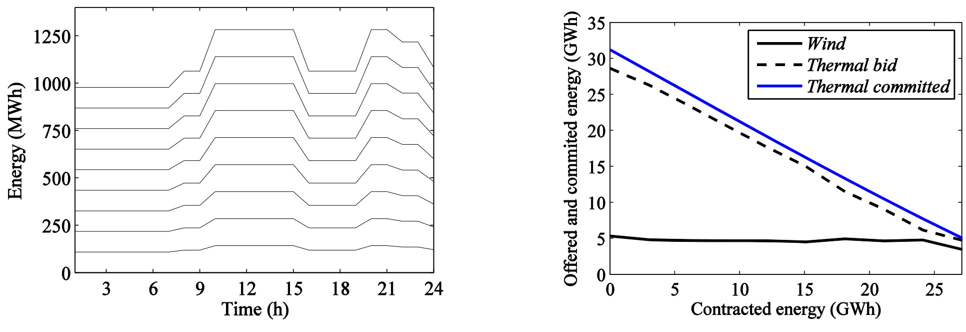

Fig 3. Left: bilateral contract; right: market scenarios energy average.

In Fig. 3, the part of the energy offered from the wind is practically constant and the committed energy is always lower than the part of the energy offered from the thermal units. As the energy contracted increases and approaches the limit capacity of the thermal units, the difference between the committed energy and the part of the energy from the thermal units wind decreases as decreases the part of the energy offered from the wind.

5 CONCLUSION

A stochastic MILP approach for solving the offering strategy and the self-scheduling problem of a price-taker thermal and wind power producer is developed in this paper. The main results are the short-term bidding strategies and the optimal schedule of the thermal units. A mixed-integer linear formulation is used to model the main technical and operating characteristics of thermal units. The coordinated offer of thermal and wind power proved to provide better revenue results than the sum of the isolated offers. The stochastic programming is a suitable approach to address parameter uncertainty in modeling via scenarios. Hence, the proposed stochastic MILP approach proved both to be accurate and computationally acceptable, since the computation time scales up linearly with number of price scenarios, units and hours on the time horizon. Since the bids in the pool-based electricity market are made one day before, this approach is a helpful tool for the decision-maker.

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A survey on public perceptions of environmental impacts of renewable energy power plants

Anabela Botelho[1], Lígia M.C. Pinto [2*], Lina Lourenço-Gomes[3], Marieta Valente[2], Sara Sousa[4]

[1] *GOVCOPP, University of Aveiro, Aveiro, Portugal; e-mail: anabela.botelho@ua.pt*
[2] NIMA and EEG, University of Minho, Campus de Gualtar, Braga, Portugal; e-mail: pintol@eeg.uminho.pt; mvalente@eeg.uminho.pt
[3] CETRAD and DESG, University of Trás-os-Montes and Alto Douro, Vila Real, Portugal; lsofia@utad.pt
[4] ISCAC, Polytechnic Institute of Coimbra, Coimbra, Portugal; e-mail: ssousa@iscac.pt
* *Corresponding author*

SESSION: "Scientific session"

ABSTRACT

The demanding EU target regarding the share of renewables in primary energy consumption poses challenges to European governments regarding the choice of renewable energy sources and the sitting decisions of new power plants. Environmental impacts of renewable energy power plants are mostly negative for residents in the vicinity of power plants (e.g. noise, glare or visual annoyance). Nevertheless, impacts such as those on landscapes and on the fauna and flora may also affect the value that the general public attributes to renewables. Several authors have focused on the question of land availability for sitting large-scale power plants, and on the social acceptability of renewable power plants in general, and have emphasized the importance of the relationship between social acceptability and distance to power plants. This paper proposes to analyze how the perceptions of the general Portuguese population regarding the environmental friendliness of renewable and non-renewable energy power plants is affected by home location in relation to the power plant, visibility of power plants, familiarity with the different energy sources, involvement in terms of employment, and socioeconomic characteristics. The data consists of a sample of 1800 residents in mainland Portugal. Preliminary results show considerable variation regarding: the familiarity and involvement with energy sources, the degree of environmental friendliness, and the perception of specific environmental impacts by renewable energy source. In addition, visibility of renewable energy power plants varies significantly by district of residence. The understanding of public perceptions regarding renewable energy sources and of the socio-demographic characteristics of those in favor, or against, renewable energy power plants is crucial for the future feasibility and acceptability of new and eventually larger or more dispersed power plants projects.

KEYWORDS: social acceptance; perception of environmental impacts; renewable energy sources

1. INTRODUCTION

The use of renewable energy sources (RES) and energy efficiency are issues that are central to the European Union (EU) energy policy, as RES contribute substantially towards reducing CO_2 emissions, helping to meet EU's international commitments, either through curbing energy demand or by providing alternative carbon-free supplies. Furthermore, they improve energy security and can contribute to enhanced competitiveness. The use of RES for electricity generation has become a cornerstone of EU energy policy contributing to all three main energy policy goals: competitiveness, energy security and environment protection (EC, 2006).

Despite the unquestionable advantages associated to the use of RES for electricity production, these are not free of negative impacts, affecting individuals' wellbeing, particularly those living in the vicinity of the different facilities. These facilities include solar photovoltaic panels, wind turbines, forest biomass fuelled plants and dams. Since each of these renewable energy technologies capture different natural resources in different ways, the socioeconomic and environmental impacts of each technology may also vary (Devine-Wright, 2008). The following negative effects associated with the activity of these facilities are common to all RES, namely the impact on landscape (e.g. Ouyang *et al.,* 2010; Dockerty *et al*., 2012; Gordon, 2001; Chiabrando *et al.,* 2009); the occupation of land and the opportunity cost of the area occupied (e.g. Denholm *et al.,* 2009; Sarlos *et al*., 2003; Rashad and Ismail, 2000); and the effects on fauna and flora (e.g. Travassos *et* al., 2005; Wang and Chen, 2013; Jonsell, 2007; Chiabrando et al., 2009). More specific to each source is the noise effect in the case of wind farms (e.g. Pederson *et al.,* 2009; Van den Berg, 2005, 2006), and to a less extent dams (e.g. JKA, 2010); specific to photovoltaic farms are the glare effect (e.g. Chiabrando *et al*., 2009) and the rise in soil temperature (e.g. Gunerhan *et al*., 2009). The installation of hydropower dams implies, in most cases, the destruction of some heritage, which can have a significant social impact (e.g. Bakken *et al.,* 2012; Ferreiro *et al*., 2013). The public perception of these impacts, regardless of the proximity of the individuals' home location in relation to the different facilities, may affect the value given to RES and the acceptability (or lack of it) regarding the construction of new power plant projects. As stressed by several studies (e.g., Wustenhagen *et al.,* 2007; Moula *et al.,* 2013; Ribeiro *et al*., 2014; Rijnsoever *et al*., 2015), social acceptance is crucial for successful implementation of renewable energy technologies and thus must not be neglected in any efficient energy decision-making process.

This paper proposes to analyze how the perceptions of the general Portuguese population regarding the environmental friendliness of renewable energy power plants is affected by variables such as: home location, visibility of power plants, familiarity with the different energy sources, involvement in terms of employment, and socioeconomic characteristics. For the empirical study, we collected a total of 1800 questionnaires among the resident population in mainland Portugal; the questionnaires were administered during the year of 2014 by a specialized survey firm on a national sample through personal interviews.

The reminder of this paper is organized as follows. In section 2 we discuss the social acceptance of renewables. Section 3 provides an overview of the main methodological issues. In section 4 we present and discuss the results. Finally, in section 5 the main conclusions of this paper are presented.

2. SOCIAL ACCEPTANCE

Social acceptance as a decisive factor for renewables' implementation was extensively ignored in the 1980's when renewable energy policy programs began. As stressed by Wüstenhagen *et al*. (2007), most decision-makers considered that implementation was not a problem, mainly because the first surveys on renewables' acceptance, in particular regarding wind energy source, revealed very high levels of public support. However, more thorough studies analyzing the effective support of the different renewables' technologies showed that public support could not be taken for granted. Carlman (1984), one of the first researchers to address this issue, carried out a study on the acceptance of wind power among decision-makers and concluded that sitting wind turbines was closely related to important issues such as public, political, and regulatory acceptance. Other studies followed and revealed a growing concern in some aspects, such as the lack of support from key stakeholders, lack of commitment and dedication from policy makers, lack of understanding of public attitudes regarding renewables, and underestimation of the importance and significance of impacts such as landscape intrusion (Wüstenhagen *et al*., 2007).

The debate on social acceptance is rich and continuously changing, mainly because there are several features of renewable energy innovation that constantly bring new aspects into consideration, in particular i) renewable energy plants tend to be of smaller scale than conventional power plants, increasing the number of location decisions to be made; ii) given the widespread creation of externalities by the energy sector as a whole, most renewable energy technologies do not compete with existing technologies on the same level, thus making their acceptance a choice between short-term costs and long-term benefits; iii) resource extraction in fossil or nuclear energy happens below the earth' surface and thus is invisible to most of the population, while in renewable plants the energy production is highly visible and closer to where the energy consumer lives: the so-called "backyard" (Wüstenhagen *et al.,* 2007).

Although the existing research shows that renewable energies are generally supported by the public opinion, when deciding the location of specific renewable energy projects, these often face resistance from the local population. This local resistance towards renewable energy developments is often explained by the Not-In-My-Backyard (NIMBY) syndrome, which has been questioned by authors such as Wolsink (1994, 2000, 2006, 2007) who studied the validity of the NIMBYism for the specific case of wind power. According to Wolsink, the NIMBY explanation is too simplistic and considers at most a secondary issue for people opposing local renewable energy projects. Instead, Wolsink considers that institutional factors are highly important and that open collaborative approaches with the involved actors are crucial to the development of the renewable energy technologies. In another study, Bell *et al.* (2005, p.460) state that "the NIMBY concept has rightly been criticized on the grounds that it fails to reflect the complexity of human motives and their interaction with social and political institutions". Many studies have concluded that the NIMBY concept is inadequate, but few have proposed alternative solutions. A notable exception is Devine-Wright (2009)'s work in explaining NIMBY responses as "place-protective actions". This new "psychological framework" reframes the issue stating that "so-called 'NIMBY' responses should be re-conceived as place-protective actions, which are founded upon processes of place attachment and place identity. This enables a deeper understanding of the social and psychological aspects of change arising from the siting of energy technologies in specific locations" (Devine-Wright, 2009, p. 432). Knowing this, one could hardly expect a confined acronym such as NIMBY to fully capture oppositional attitudes towards RES.

There is no doubt about the complexity around the social acceptance of renewable energy innovations. According to Wüstenhagen *et al.* (2007), the concept of social acceptance of renewable energy innovations is multi-dimensional, including socio-political acceptance, community acceptance and market acceptance.

Socio-political acceptance is "social acceptance on the broadest, most general level" (Wüstenhagen *et al.*, 2007, p. 2684). It refers to the role of citizens. It is primarily manifested through general support for a renewable-based technology or for policies supporting its development. This is often measured through opinion polls that represent the individuals' aggregated attitudes (Lippmann, 1922; Rijnsoever and Farla*,* 2014; Rijnsoever *et al.,* 2015). Socio-political acceptance helps establish conductive conditions for implementing innovations. It is about the willingness among actors (public, key stakeholders and policymakers) to generate institutional changes and policies that create favourable conditions for new technologies (Wolsink, 2012).

Community acceptance refers to the role of consumers as voluntary or involuntary users of technology. It plays an important role in the cases where the adoption of an innovation affects groups of agents, such as the sitting decisions for renewable energy installations (Rijnsoever *et al.,* 2015). An efficient community approach is essential to renewables deployment. Studies on this subject show that some factors seem to be crucial to a successful renewable project, namely a collaborative decision-making process, employing effective forms of community involvement; projects which the community can strongly identify with, as a result of effective involvement and participation in the sitting process or due to high community involvement in the management and/or ownership; the perception of how well the new system "fits" into the identity of the community; decision-making process perceived as being fair; and the existence of mutual trust between community members and the investors and owners of the infrastructure (Devine-Wright *et al.,* 2007; Walker and Devine-Wright, 2008; Walker *et al*., 2010; Wolsink, 2012).

Finally, we have market acceptance, or the process of market adoption of an innovation. One of the main problems associated with green power marketing (and trading) is the separation between (physical) supply and demand. In the renewable energy market, consumers have the opportunity to "switch" to renewable energy supply without being actually involved in the physical generation. However, if consumers demand increasing amounts of green power, there still need to be sitting processes for power plants to meet this demand. In the context of market acceptance, the actors (incumbents, investors, new firms and consumers) have an important role and their willingness-to-pay (WTP) or to invest in renewable energy projects is extremely important (Wolsink, 2012). To better understand the concept of market acceptance, we extend our analysis beyond the consumer and highlight also the investor (note that consumers can simultaneously be investors). For instance, large renewable energy firms are subject to several path dependencies and issues such as how social acceptance is built between these. Moreover, other aspects to consider are how international companies act in different countries, how their position affects the opportunities of other potential investors and how they use their influence in crucial political decisions (Wüstenhagen *et al.,* 2007).

This model of analysis has the merit of clarifying the complex concept of social acceptance through its different components. In this paper we focus on socio-political acceptance as an aggregate of the individual attitudes of citizens.

3. SURVEY DESIGN AND IMPLEMENTATION

With the aim of understanding public perceptions regarding the use of RES for electricity generation in Portugal, we designed five different questionnaires: one for each energy source (photovoltaics, hydro, wind, and forest biomass) and one questionnaire for all renewables (forest biomass was excluded given the unfamiliarity revealed by the population regarding this particular energy source, as explained in next section). The survey was conducted through personal interviews during the first semester of 2014. A total of 1800 questionnaires was collected, of which 1523 were complete.

The questionnaires are divided in three sections. The first section focuses on respondents' knowledge, opinions and preferences over renewable energy sources; the second focuses on the elicitation of respondents' valuation regarding the effects of RES on the environment. Finally, the third section contains questions on socio-demographic characteristics. Except for the second section, most questions are comparable across questionnaires, being exactly the same in the first part of all questionnaires. The focus of the present investigation is thus on the first part of the questionnaire. The instrument was developed in an interactive process using focus group discussions and think-aloud sessions to improve the questionnaire (Botelho *et al*., 2014).

4. RESULTS

The sample, composed of 1523 complete questionnaires, is characterized by subjects with mean age of 49 years old, while the youngest and oldest respondent were 18 and 91 years old, respectively; most respondents were married (64%) or single (24%). Regarding the work situation, most respondents are employed or retired (46% and 24% respectively), and have either secondary or higher education (29% and 32%); however approximately 14% have only attained primary school level education.

Due to high non-response rate regarding the income variable (only 36% of the respondents answered the question), the value of the monthly electricity bill is used as a proxy for the income level for comparison purposes. It is assumed that a higher electricity bill is related to more electrical appliances and thus higher income. Average electricity bill is 66 Euros.

In order to understand the social acceptability of RES power plants it is important to characterize respondents' attitudes towards environmental issues. When asked about the major environmental problems in Portugal, respondents consider water and air pollution the most significant (51% and 50% respectively), followed by waste management (48%) and climate change (46%). RES are familiar to most respondents, the least familiar are wave-energy, geothermic and forest biomass. Wave energy is just exploratory in Portugal, thus respondents' unfamiliarity is expected, and the same is true for the case of geothermic energy which is not present in mainland Portugal (only in the archipelagos). Forest biomass, however, is present in Portugal, although with a significantly lower penetration rate, so it is therefore surprising that only 54% of the respondents indicate knowledge of this particular energy source. In line with previous results (e.g. Pinto *et al.,* 2015; Sousa, P. *et al*., 2015; Sousa, S. *et al*., 2015), 27% of the respondents see some RES power plant in their daily lives, and, of those who indicated this, the most frequent are wind farms (72%), solar PV farms (35%), hydropower (13%), and only 3% state seeing forest biomass power plants. Most frequently the power plants are seen from either respondents' homes or during their daily commuting (Table 1).

Table 1: Descriptive statistics

Variable	Description	Mean/frequency
Age	Age of respondent	49.11 (16.55)
Work situation	Unemployed	12.7%
	Housemaid	3.01%
	Student	3.71%
	Retired	24.23%
	Self-Employed	10.02%
	Employed	46.33%
Marital status	Married	64.03%
	Divorced	6.25%
	Single	23.94%
	Widow	5.78%
Schooling	Primary school (years 1-4)	13.60%
	Preparatory school (years 5-6)	4.92%
	Secondary school (years 7-9)	13.60%
	Post-secondary (years 10-12)	28.80%
	Undergraduate degree	32.49%
	Master degree	5.21%
	PhD	0.94%
	Other	0.43%
Electricity bill	Monthly electricity bill in Euros	66.47 (63.63)
Environmental problems	Air pollution	50.85%
	Water pollution	51.48%
	Over-exploitation of natural resources	9.10%
	Decreased biodiversity	16.96%
	Climate change	46.03%
	Waste	48.19%
	Other	3.28%
Knowledge	Wind	98.55%
	Solar	95.33%
	Forest biomass	53.58%
	Geothermic	56.51%
	Hydropower	94.94%
	Wave	70.83%
See RES power plant		26.99%
If yes,	See wind farm	72.20%
If yes,	See forest biomass	2.93%
If yes,	See hydropower plant	12.68%
If yes,	See solar	34.63%
If yes,	See from residence	50.85%
If yes,	See from work	11.68%
If yes,	See daily commute	54.74%

(Standard deviations in parentheses)

There, however, are some important regional variations, reflecting the geographic distribution of RES power plants. In Viana do Castelo, Portalegre and Guarda, more than 60% of the respondents view some RES power plant; while less than 20% see some in the districts of Beja, Braga, Porto, Setúbal and Évora. Regarding wind farms, in Bragança, Guarda, Leiria, Lisboa, Portalegre, Santarém, Viana do Castelo, Vila Real, and Viseu, more than 60% of the sample see a wind farm from their homes, work, or daily commutes; while in Évora is the only district where respondents do not see any wind farm from their homes or in daily commutes. Respondents from Beja and Portalegre are the ones that see hydropower plants with highest frequency. In most districts the percentage of respondents that state seeing a hydropower plant is lower than 10%, which is reasonable given the location of dams in Portugal. Respondents' answers regarding solar-photovoltaic is not reliable as in most districts respondents state they see these farms daily, while the only solar-photovoltaic farms in Portugal are located in Beja and Évora, so, respondents may be referring to individual panels in buildings or in some industrial facility, rather than to actual farms. In 11 districts no respondent states seeing a forest biomass power plant; in the others the percentage stating seeing a forest biomass power plant is lower than 10%, and again there are some responses in the data which probably are not accurate because of lack of information and familiarity with this RES, in particular (Table 2).

Table 2: Descriptive statistics by district – visibility of power plant

District	See RES	See wind	See forest biomass	See hydropower plant	See solar power plant
Aveiro	24.10	55.17	0.00	3.45	58.62
Beja	28.57	100.00	0.00	50.00	50.00
Braga	20.14	60.71	3.57	10.71	50.00
Bragança	47.37	88.89	0.00	11.11	33.33
Castelo Branco	35.71	80.00	0.00	10.00	40.00
Coimbra	41.54	77.78	3.70	11.11	33.33
Faro	30.30	80.00	0.00	20.00	25.00
Guarda	64.00	93.75	6.25	25.00	6.25
Leiria	43.30	78.57	0.00	4.76	33.33
Lisboa	21.73	82.35	0.00	1.47	35.29
Portalegre	52.63	90.00	0.00	30.00	0.00
Porto	16.67	33.33	4.44	35.56	44.44
Santarém	31.94	69.57	4.35	8.70	39.13
Setúbal	14.38	52.38	23.81	14.29	42.86
Viana Castelo	67.57	100.00	4.00	8.00	4.00
Vila Real	33.33	90.00	0.00	10.00	10.00
Viseu	45.10	77.27	0.00	13.64	36.36
Évora	4.00	0.00	0.00	0.00	100.00

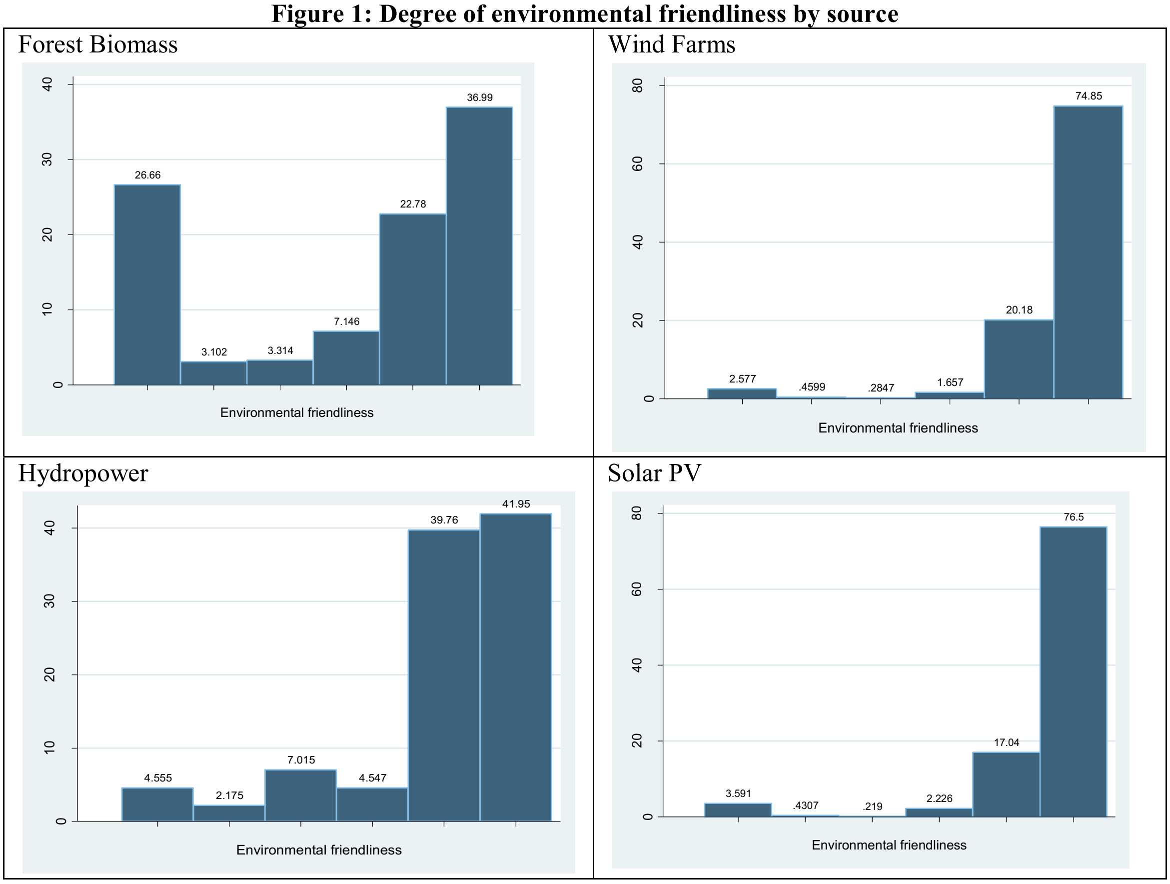
Regarding respondents' knowledge with respect to the different RES, wind, solar-photovoltaic and hydropower are known to most respondents in all districts. The energy source that is less familiar is forest biomass. Residents in Beja and Castelo Branco are the less familiar with this RES. The most familiar live in Guarda district (Table 3).

Table 3: Descriptive statistics by district – knowledge about the different RES

District	Know wind	Know forest biomass	Know hydropower plant	Know solar power plant	Know geothermic	Know wave energy
Aveiro	93.13	58.88	95.33	98.13	57.94	68.22
Beja	100.00	21.43	100.00	100.00	35.71	42.86
Braga	97.84	56.83	90.65	94.96	58.27	69.78
Bragança	100.00	57.89	100.00	84.21	68.42	73.68
Castelo Branco	89.29	35.71	89.29	92.86	39.29	39.28
Coimbra	96.92	64.62	93.85	98.46	64.62	72.31
Faro	98.45	43.94	96.97	96.97	50.00	68.18
Guarda	100.00	68.00	88.00	88.00	44.00	68.00
Leiria	97.94	60.82	93.81	92.78	62.89	70.10
Lisboa	99.36	49.20	97.76	96.79	56.87	76.67
Portalegre	94.74	47.37	94.74	94.74	52.63	57.89
Porto	98.89	53.70	95.56	94.81	55.93	74.81
Santarém	100.00	61.97	98.59	100.00	50.70	76.06
Setúbal	99.31	53.76	93.84	92.47	63.36	69.86
Viana Castelo	97.30	45.95	97.30	94.59	48.65	72.97
Vila Real	100	46.67	90.00	96.67	36.67	50.00
Viseu	98.04	58.82	96.08	98.04	62.75	66.67
Évora	100.00	44.00	80.00	84.00	50.00	60.00

To understand the perception by respondents of the degree of environmental friendliness of RES, they were asked to rate each RES on a 5 point scale (1 not friendly; 2 somewhat not friendly; 3 indifferent; 4 somewhat friendly, 5 very friendly). Overall, more than 5% find all four RES as somewhat or very environmental friendly. However there is some variation across sources (Figure 1); in the case of forest biomass there is a significant percentage of respondents that are not familiar with the source and consequently are unable to rate it with respect to its environmental friendliness. Concerning hydropower and forest biomass plants, a non-trivial percentage of respondents find them not friendly (respectively 9.2% and 6.4%). Results on the four RES considered reveal significant regional differences between respondents' opinion of the degree of environmental friendliness of RES.

Figure 1: Degree of environmental friendliness by source



Legend: 0 don't know; 1 not friendly; 2 somewhat not friendly; 3 indifferent; 4 somewhat friendly, 5 very friendly

To explain the degree of environmental friendliness of RES, and to analyze the regional variability in respondents' preferences, an ordered probit model is specified. The dependent variable is the degree of friendliness varying between 1 and 5, as explanatory variables we include the district of residency, the age and gender of the respondent, whether the respondent buys environmentally friendly products (to proxy for environmental preferences), a variable relating to the involvement of the respondent with the RES, a binary variable taking the value 1 if the respondent sees a RES power plants daily, and finally the amount of respondents' electricity bill (as a proxy for income, as the variable income had many missing observations).

Results in Table 4 reveal consistency across RES. Respondents involved with the RES are more likely to consider the RES environmentally friendly, as expected. Also relevant is whether respondents see RES power plants in their daily lives. For wind farms, the effect of seeing a RES power plant on respondents' probability of finding environmentally friendly is positive, however, the effect for Hydropower environmental friendliness is negative.

Also noteworthy is the regional variation in results. Residents in Beja and Viana do Castelo consider the RES less environmental friendly, while residents in Lisboa, Santarém and Setúbal find them more environmental friendly, than residents in Aveiro. Residents in Lisbon, in general, find RES more environmental friendly (except for forest biomass). The remaining districts do not show statistically significant differences.

In summary, respondents from different districts have different opinions regarding each RES, and their opinion is not independent of the particular RES under consideration. Wind farms and solar photovoltaic farms are more likely considered very environmental friendly than other sources. If we consider the probability of being classified as friendly or very friendly, these two energy sources have a probability of 98% and 97%, respectively, while hydropower has a probability of 85% and forest biomass has 83%.

Although all four renewable energy sources considered in this study are environmental friendly, in the opinion of the majority of the respondents, the degree of friendliness varies between sources and between districts of residence.

Table 4: Ordered probit estimation results by RES

	WF	HP	SPV	FB
	Coeficient (robust stdev)	Coeficient (robust stdev)	Coeficient (robust stdev)	Coeficient (robust stdev)
Age	-0.0011 (0.0022)	0.0011 (0.0018)	-0.0015 (0.0023)	0.0015 (0.0022)
Male	-0.0110 (0.0741)	0.0375 (0.0602)	-0.0435 (0.0759)	-0.1494** (0.0696)
Electricity bill	0.0007 (0.0006)	0.0005 (0.0007)	0.0003 (0.0006)	0.0009 (0.0006)
Env. Products	0.1454 (0.0967)	0.0812 (0.0804)	0.1536 (0.1009)	0.0753 (0.09489)
See-RES	0.1432* (0.0883)	-0.1664** (0.0690)	0.1396 (0.0890)	-0.0930 (0.0764)
Involvement	0.2410** (0.1117)	0.1266 (0.0905)	0.2982*** (0.1182)	0.2195** (0.0980)
District$^{\alpha}$				
Beja	-0.6816** (0.3337)	-0.0113 (0.2591)	-0.7342** (0.3198)	-1.5871*** (0.4507)
Braga	-0.0472 (0.1673)	0.1073 (0.1464)	02158 (0.1804)	0.1028 (0.1707)
Bragança	-0.1047 (0.2904)	0.1930 (0.2264)	-0.2511 (0.2984	-0.2854 (0.3106)
Castelo Branco	-0.2430 (0.2597)	-0.3210 (0.2063)	-0.3898 (0.2647)	-0.1894 (0.2492)
Coimbra	-0.2169 (0.1986)	0.0704 (0.1656)	-0.2073 (0.1956)	0.0058 (0.1863)
Faro	0.0279 (0.2008)	0.0834 (0.1690)	-0.1797 (0.2046)	0.1830 (0.2141)
Guarda	0.1347 (0.3765)	-0.2294 (0.2965)	-0.1259 (0.3477)	0.2200 (0.3505)
Leiria	0.2659 (0.1894)	0.3390** (0.1635)	0.0516 (0.1846)	0.0665 (0.1833)
Lisboa	0.6167*** (0.1531)	0.2897** (0.1308)	0.4693*** (0.1547)	0.0888 (0.1490)
Portalegre	0.2169 (0.3675)	0.3706 (0.2341)	0.1204 (0.5132)	0.4790 (0.5334)
Porto	0.2687* (0.1481)	-0.0532 (0.1298)	0.3013** (0.1525)	0.0570 (0.1526)
Santarém	0.2367 (0.1957)	0.1298 (0.1807)	0.3502* (0.2082)	0.4587** (0.2003)
Setúbal	0.6321*** (0.1818)	0.4203*** (0.1636)	0.5598*** (0.1889)	0.0442 (0.1798)
Viana Castelo	-0.4176** (0.2040)	0.1107 (0.2089)	-0.4923** (0.2167)	-0.1486 (0.2465)
Vila Real	-0.1683 (0.2397)	0.0947 (0.2123)	-0.2289 (0.2777)	-0.1287 (0.2700)
Viseu	0.0593 (0.2146)	0.0003 (0.1761)	0.0147 (0.2201)	0.1349 (0.1992)
Évora	0.4860 (0.3110)	0.4698* (0.2808)	0.3088 (0.3262)	0.8468** (0.3315)
Prob (outcome 1)		0.0257*** (0.0041)	0.0050*** (0.0018)	0.0413*** (0.0058)
Prob (outcome 2)	0.0036** (0.0016)	0.0713*** (0.0068)	0.0021* (0.0012)	0.0483*** (0.0064)
Prob (outcome 3)	0.0156*** (0.0032)	0.0455*** (0.0054)	0.0212*** (0.0037)	0.0821*** (0.0082)
Prob (outcome 4)	0.1894***	0.3951***	0.1599***	0.3026***

	(0.0098)	(0.0127)	(0.0093)	(0.0137)
Prob (outcome 5)	0.7909*** (0.0102)	0.4624*** (0.0129)	0.8118*** (0.0099)	0.5257*** (0.0147)
N	1484	1448	1467	1117
Wald-chi2	80.21***	43.38***	77.01***	45.9***

$^{\alpha}$ reference category is Aveiro. *significant at 10%; **significant at 5%, ***significant at 1%. Robust standard deviations in parentheses; WF: wind farms, HP: hydropower, SPV: solar photovoltaic, FB: forest biomass.

5. DISCUSSION AND CONCLUSIONS

Renewable energy sources have become popular in the context of climate change policies. The EU has set increasingly more stringent targets for greenhouse gas emissions, whose attainment relies heavily on a more intensive use of renewable energy sources. The intensification of use of RES requires the installation of new wind and solar farms, hydropower plants and biomass plants, which then requires sitting decisions for these facilities. As argued previously, these decisions are multidimensional and affect a multitude of stakeholders. Botelho *et al.* (2015) find significant effects of the installation of RES facilities on residents living nearby. The results obtained in the present study support the general claim that renewable energy sources are perceived as environmentally friendly, and consequently socially acceptable. However, the results also support the hypothesis that the acceptability of renewable energy sources varies across sources and locations. Moreover, the degree of environmental friendliness varies not only by district of residence, but also with socio-demographic characteristics of the respondents and also their relationship with the environment and the RES in particular.

While out results are in line with previous literature, showing a general social acceptance of RES, the present paper adds some qualifications to this general result. First, there is a considerable difference between respondents' opinion regarding the specific RES, in particular wind and solar energy are considered the friendliest, followed by hydropower and forest biomass. In addition, we observe regional and socio-demographic variation which suggest preferences vary with experience and familiarity with specific energy sources. Therefore a more nuanced and detailed analysis of the social acceptance of the different RES is called for when discussing and developing renewable energy power plants.

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Combined penetration of wind and solar generation with plug-in electric vehicles

José Villar[1], Enrique Salas[1], Fco Alberto Campos[1],

[1] *Institute for Research in Technology, Technical School of Engineering, Comillas Pontifical University, C/ Santa Cruz de Marcenado, 26, 28015 Madrid-Spain, jose.villar@iit.comillas.edu, enriquesalas1992@gmail.com, alberto.campos@iit.comillas.edu*

ABSTRACT

Combining large penetration of wind and solar generation with Plug-in Electric Vehicles (PEVs) seems a promising solution for energy cost saving and emissions reduction. PEVs connected to the grid with smart charging strategies can be an effective way to integrate non-dispatchable renewable generation, smoothing the load curve, contributing to the system stability by providing regulation services, and moving unhealthy emissions away from city centers.

This paper analyzes the combined penetration of PEVs, and wind and solar generation using a Unit Commitment model for the Spanish power system, providing some insight on how the penetration of these technologies affects relevant variables such as energy and reserve, thermal plants behavior (such as starts-up and shut-downs, technological energy share, generation costs or emissions) and systems costs.

KEYWORDS: Electric vehicle, wind and solar power integration, emissions, unit commitment.

1 INTRODUCTION

Progressive replacement of conventional Combustion Vehicles (CVs) with Plug-in-Electric Vehicles (PEVs) may lead to important benefits to current cities, making them smarter in the sense of [1], and reducing noise and emissions pollutions, as analyzed in [2]. However, this new electricity demand must be efficiently managed with intelligent charging strategies so that the system does not suffer from excessive plants stress, worsening their schedules and increasing their ramp requirements,[3].

In addition, using PEVs batteries as intelligent distributed energy storage systems can help to the integration of new renewable energy, as has been pointed out in several works, for example in [3], where an analysis of the combined penetration of wind and PEVs and solar and PEVs was performed. Indeed PEVs facilitate the integration of non-dispatchable wind and solar generation by consuming at valley hours, generating at peak times, and even providing regulation services to compensate for the increased needs of regulation capacity that these intermittent generation may cause.

Therefore, the analysis of the net benefit of such potential wind and PEV expansion becomes a very relevant topic to investigate. Since the problem to face is large and complex, many aspects such as investments, market electricity impact and relevant externalities have been considered and modeled. References [2], [3] and [4] present an extensive literature review of the authors on previous related research works.

This paper extends the analysis performed in [3] by looking with more detail at the impact of different levels of wind and solar generation, for a fixed large PEVs penetration, on the operation and schedules of conventional thermal plants, electricity prices, CO2 emissions and system costs. Market results have been obtained from a detailed hourly hydro-thermal Unit Commitment model (UC, already used and described in [3], [2] and [5]) with weekly water management [5]. It provides, among others, energy and reserve prices and schedules, and thermal units emissions, without considering network constraints or distribution grid problems [6]. Simulations have been performed for the first week of May 2011, so results for this particular week, with reasonable amount of both wind and solar generation, are provided. The extension to the whole 2011 is under progress.

This paper is organized as follows. Section 2 briefly describes the model, the main input data and the case studies analyzed, section 3 presents the main results, and section 4 concludes the paper.

2 MODEL AND DATA

2.1 Model description

Simulations have been performed with a UC model which is a hydro-thermal-PEV UC for the joint energy and reserve dispatch that minimizes the total system costs, including production variable costs, startups, shutdowns and CO_2 emission costs for each thermal unit (see [3], [2] and [5]). Inelastic net demand (demand minus non dispatchable generation) is supplied by thermal units, hydropower generation, renewable generation, pumping cycles (generating or consuming), and PEVs (generating or consuming). Both, PEVs generation and consumption for a PEVs penetration of 45% (100% meaning that all CVs have been replaced by PEVs) are analyzed in this paper, taking into account different levels of wind and solar generation. Price is set as the dual variable of the demand balance equation, corresponding to the system marginal cost. Minimum and maximum prices were set to 0€/MWh and 180€/MWh, corresponding to spillages and non-served energy hours respectively.

Reserve availability requirements are supplied by thermal units, hydropower generation, pumping generation (only when turbining), and PEVs (although PEV supplying reserve has not been considered in this paper). The dual variable of the reserve balance equation provides a unique reserve price market for both the upward and downward reserves (as it is the case of the Spanish market).

Hydro units are modeled following [5], without topological relations, and using historic constraints on productions and cleared reserves per week for weekly optimization. Water and PEVs are dispatched in a two step process. They are optimally allocated on the first step, and remain fixed on the second one, so that the prices computed correspond to the marginal cost of thermal plants.

Only the V2G charging strategy of PEVs (optimal charging with generation) has been used, with PEVs decisions centrally optimized by a hypothetical Electric Vehicle Operator, minimizing the total system cost. However, the model accepts four different PEVs charging strategies ([3] and [2]). PEVs with same behavior have been grouped by fleets, as in precedent authors' works,[2].

A minimum charge of 80% is guaranteed before unplugging PEVs, and PEVs batteries efficiency has been set to 90%. PEVsdoes not supply electricity to the grid unless the batteries charge is above 60 %.

2.2 Input data and case studies

Simulations are based on the structure of Spain's thermal generation (nuclear, national coal, imported coal, combined cycle and fuel gas) in 2011, and demand and reserve requirements for the first week of May 2011. Reserves (to deal with large wind or solar generation capacities) have not been increased with respect to the historical ones. Although this is coherent with the Spanish System Operator practice (probably due to a possible overestimation of reserves, see[9]), some increment for very large renewable penetration should be expected. System demand, non-dispatchable generation (wind, solar and others), and the weekly parameters for hydro units are taken from[10],[11]and[12], see Figure 1.

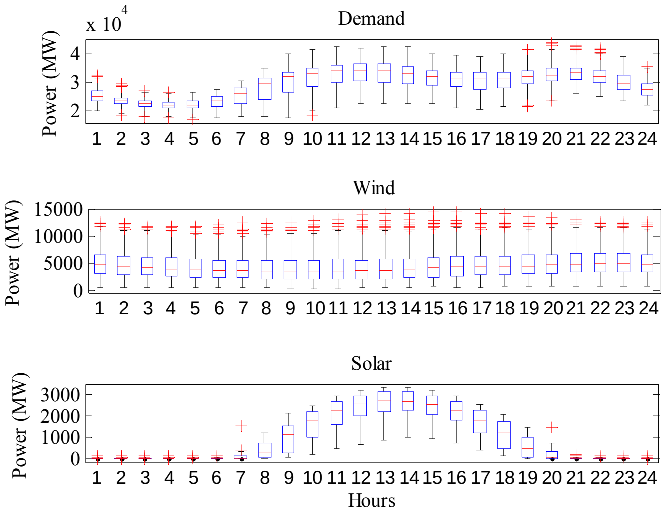


Figure 1: Box-plots of hourly demand and wind power.

TABLE I
BASE CASE ANNUAL VALUES

	Demand	**Wind**	**Solar**
Energy (TWh)	256.1	41.5	7.6
Installed capacity (GW)	-	22	4.05
Capacity factor (%)	-	22%	20%

Wind and solar investment costs have been set to 1,500€ per installed kW, [7], and 2,500€ per installed kW, [8], respectively. Wind and Solar capacity factors (computed for the whole 2011, see TABLE I) are respectively 22% and 20%. Lifespan has been set to 20 years.Wind penetration levels,for the different scenarios considered, are identified with labels ΔW*n*, where *n* is a factor that increases the base case production (see Table I) in multiples of 8 GWh, so for example ΔW_1corresponds towind generation increment of 8 GWh with respect to the base case. Solar generation capacity increments follow the same logic, so that ΔS_2 means a solar production increment to 16 GWh with respect to the base case production. As already mentioned, for simplicity the percentage of PEV penetration level has been fixed to 45%, where 100% means that all CVs have been replaced by PEVs.

The characteristics of the fleets used are detailed in [2]: traveled daily distances, batteries capacity, number of vehicles (for a 100% penetration) and driving schedules. Actual 2011 calendar was used. PEVs not driving are supposed to be connected to the distribution grid and available for charging.

3 CASE STUDIES RESULTS

3.1 Thermal units Commitment

Figure 2 and Figure 3 show the thermal gap for the selected week for the different solar and wind penetration scenarios, to be supplied only with thermal generation.

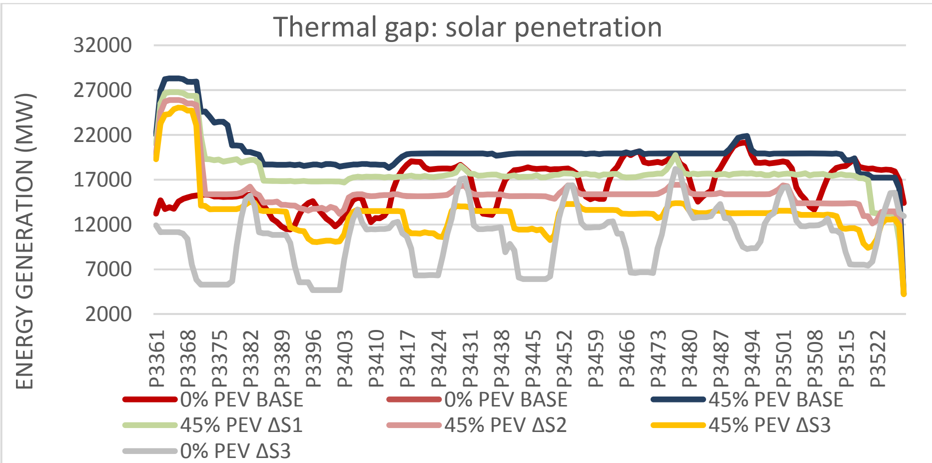


Figure 2: Thermal Gap for solar penetration scenarios

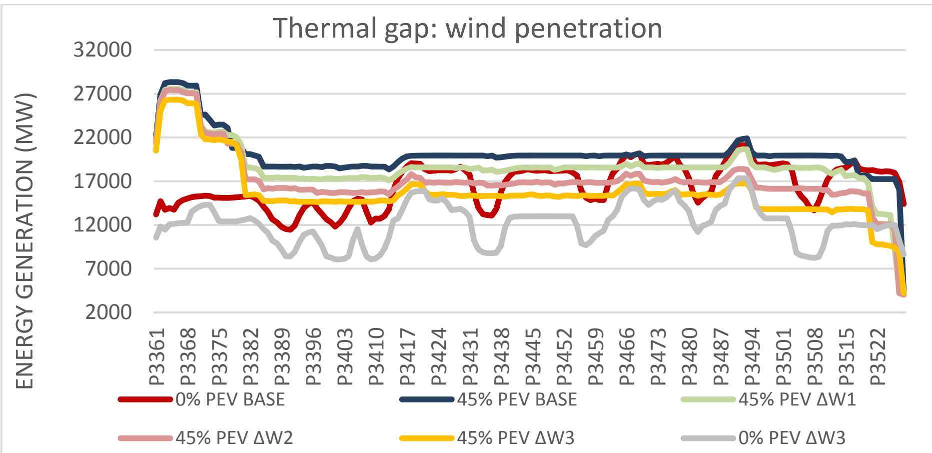


Figure 3: Thermal Gap for wind penetration scenarios

Base case 0% PEV (0% PEV with no additional solar or wind) corresponds approximately to the real 2011 existing situation, and shows the original peaks and valleys of the thermal gap. A penetration of 45% of PEV increases significantly the total energy consumption but smoothes the thermal gap thanks to the optimal allocation of PEV charging periods. Then increasing solar or wind generation has different impact on the thermal gap. While both technologies reduce it, and so the total thermal production, the reduction is larger for the solar case, even if the utilization factors are very similar for both technologies. This is due to the hourly production pattern of solar technology (with respect to the more constant hourly wind production pattern), which concentrates on peak hours where thermal generation is larger and thus more expensive. For this same reason solar generation increases thermal gap variability, but decreases the final energy production cost, as can be seen in TABLE IV.

Figure 4 shows the technologies supply for both solar and wind penetration scenarios.

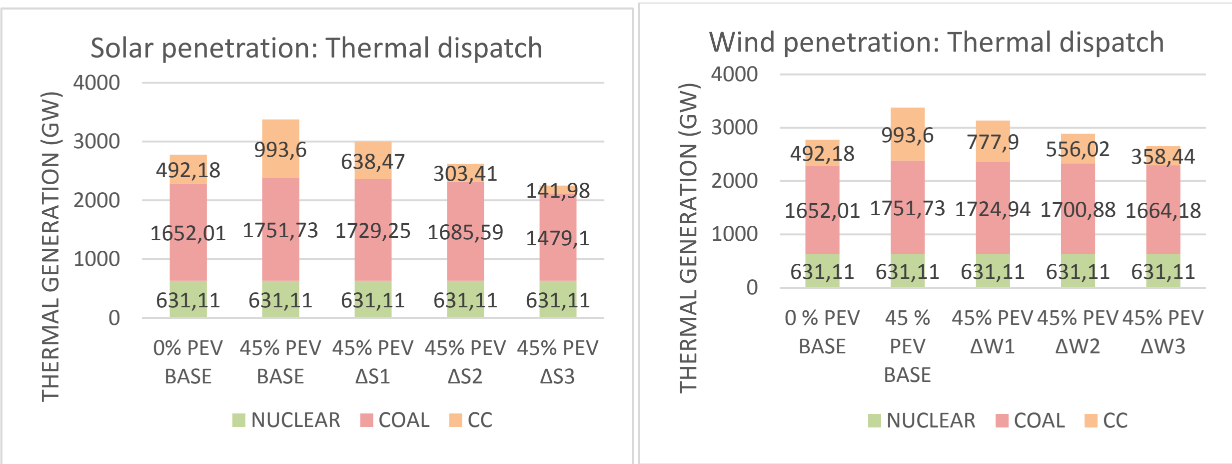


Figure 4: Thermal production by technology for a) solar and b) wind penetrations scenarios

When PEV penetration goes from 0% to 45% both the energy consumption and the thermal gap increase significantly. Nuclear plants, with the cheapest variable costs, keep their production constant for all scenarios since they are always producing at their maximum capacity. Coal plants, with the cheapest variable costs after the nuclear ones, increase their production up to their maximum capacity (also considering the reserve commitment), and the additional energy needed is supplied by combined cycles, in particular for large demand and low solar hours for the solar scenarios.When renewable generation increases, both coal but mostly combined cycles (CC) reduce their production. This reduction is greater for the solar cases since solar production is greater for high demand hours when thermal generation is also higher.

3.2 PEV behavior

Figure 5 shows the daily patterns of solar and wind generation versus the charge-generation pattern of PEV.

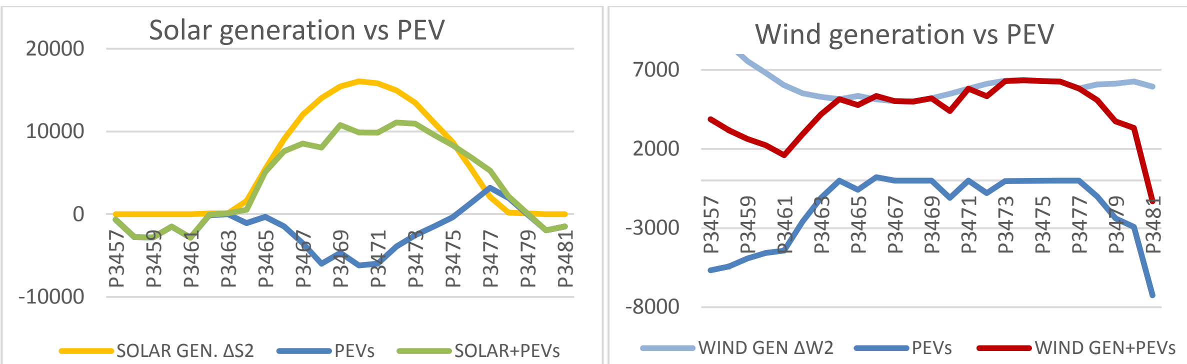


Figure 5: a) Solar and b) wind generation vs PEV generation-consumption

For the solar scenarios, PEV charges partially at night to be ready for commuting trips early in the morning, but mostly at high solar production hours to store the extra solar energy. At dusk, when solar production decreases but demand is still very high, PEVs supply part of this energy to the grid, behaving like pump-storage units. This behavior is not present for wind, where PEVs charge mainly at night and almost do not generate. This entails that the storage capability of PEVs more suited for solar penetration scenarios. In any case the possibility of optimally allocating the PEV consumption reduces significantly the need for storage-generation cycling units. In this sense Figure 6 shows how pump-storage units reduce their cycling behavior with large PEV penetration and even changing the hours where pumping takes place.

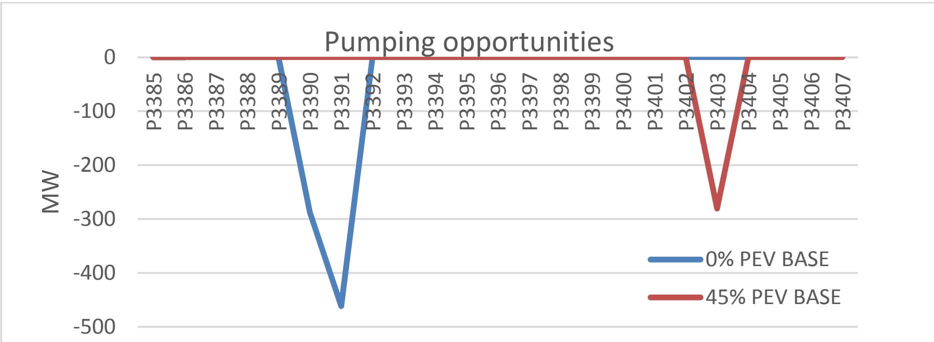


Figure 6: impact of PEV on pump-storage units' behavior

3.3 **Reserves**

Figure 7 shows the reserve allocation for the different solar and wind penetration scenarios.

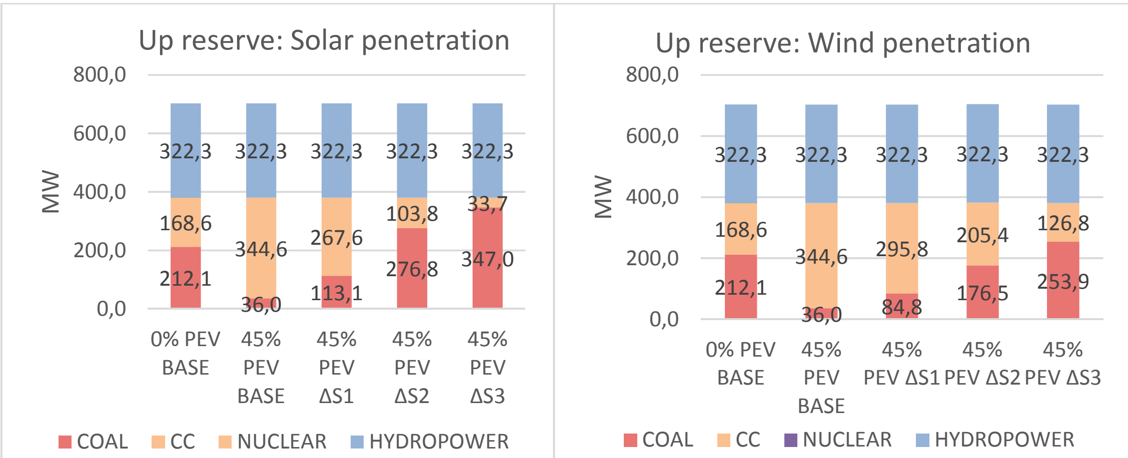


Figure 7: Hourly average up reserve allocation for a) solar and b) wind penetration scenarios

When PEV penetration goes from 0% to 45% both the energy consumption and the thermal gap increase and coal plants produce at their maximum capacity, providing almost null reserve. When solar and wind increase, the thermal gap decreases and coal plants reduce their production increasing the reserve they provide. Again solar production pattern allows for more thermal gap reduction, and so the reserve provided by coal plants is larger for solar penetration scenarios than for wind ones. Down reserve shows a similar behavior.

3.4 **Operating costs analysis**

To help understanding the following sections, TABLE II collects the average costs and emissions used for the thermal technologies.

TABLE II
Average thermal technologies variable costs and emissions per plant

Technology	Startup Cost [€]	Shutdown Cost [€]	Fuel Cost [€/MWh]	CO_2Emissions Cost[€/MWh]	CO_2Emissions [T/MWh]
Nuclear	93,467.55	18,693.51	10.45	0	0
Coal	26,897.08	4,168.60	30.23	9.77	1.01
CC	54,142.73	7,212.77	43.04	3.95	0.39
FG	24,135.81	1,953.26	72.51	6.09	0.61

3.4.1 Fuel Cost

Figure 8 represents the fuel cost allocation for each thermal technology.

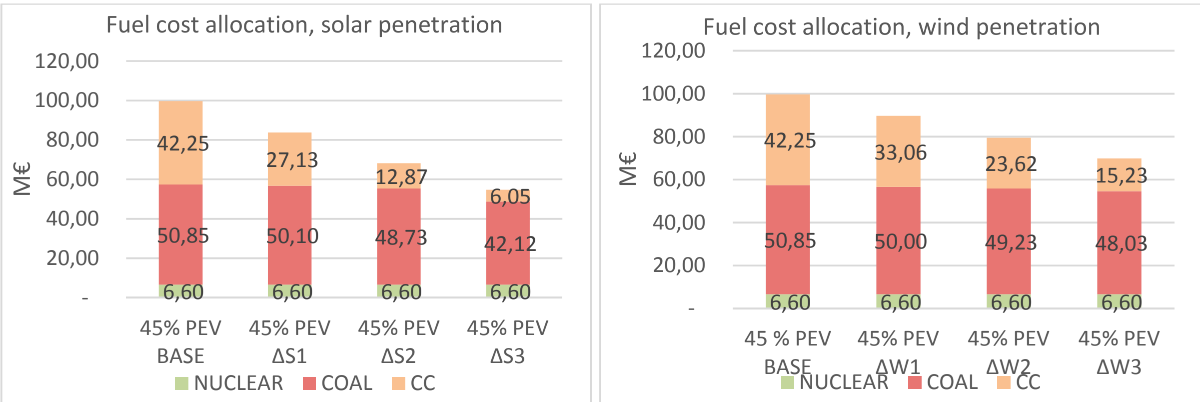


Figure 8: a) solar and b) wind scenarios fuel cost allocations

Nuclear plants are always producing at maximum capacity so their production and their costs remain constant for all scenarios, as expected. Coal plants are also producing almost at their maximum capacity due to the PEVs large consumption. However, as renewable energy increases, coal plants production decreases and, as it has already been mentioned, this decrement is larger for solar penetration due to its hourly production profile. This has an additional consequence. Indeed, even if combined cycles production is much lower than coal one, its impact on the cost is larger due to their larger variable cost. For example, from Figure 4, coal production in scenario ΔS3 is 65.7% of the total production. From Figure 8 coal impact on the total cost is almost 77%. On the contrary CC production is about 6.3% while its impact on the cost is around 11%. In scenario ΔS3 it is also possible to appreciate a significant decrement of 17% of coal costs with respect to the base 45% PEV scenario, while this reduction is only around 5.5% for scenario ΔW3. Again large penetration of installed capacity of solar generation seems to be more profitable for the system operation than same capacity increment of wind generation. It will be shown however, than the larger investments cost of solar technology makes the solar investments less profitable than wind ones.

3.4.2 CO_2 emission cost

CVs emissions can be estimated as shown in TABLE III, where the total kilometers driven by the vehicles of the 21 fleets in [2] for the first week of May are used, distinguishing between gasoline and diesel vehicles whose average CO_2 emissions are slightly different.

TABLE III
Basic data of Combustion vehicles

Fuel	**%**	**Consumption [l/100 km]**	**Price [€/l]**	**CO_2 Emissions [T CO_2 / km]**	**CO_2 Emissions Cost [€/T CO_2]**
Gasoline	46.10	18,693.51	1.47	166.15	9.99
Diesel	53.90	4,168.60	1.39	126.7	9.99

Figure 9 shows the total CO_2 emissions of the power system and CVs, and Figure 10 their cost allocation over the thermal technologies. The replacement of CVs with PEVs implies an important decrement of CO_2 emissions (comparing 0% PEV and 45% base cases). However, the reduction of CO2 emissions due to new renewable generation is not very large due to the extra PEVs demand. Indeed, due to this extra demand, coal plants are producing at maximum capacity and are complemented with CC plants, so the reduction of the thermal gap reduces only the additional CC production, whose emissions are almost negligible, with a final low impact on the total system emissions. Again this reduction is higher for solar penetration due to its hourly generation profile.

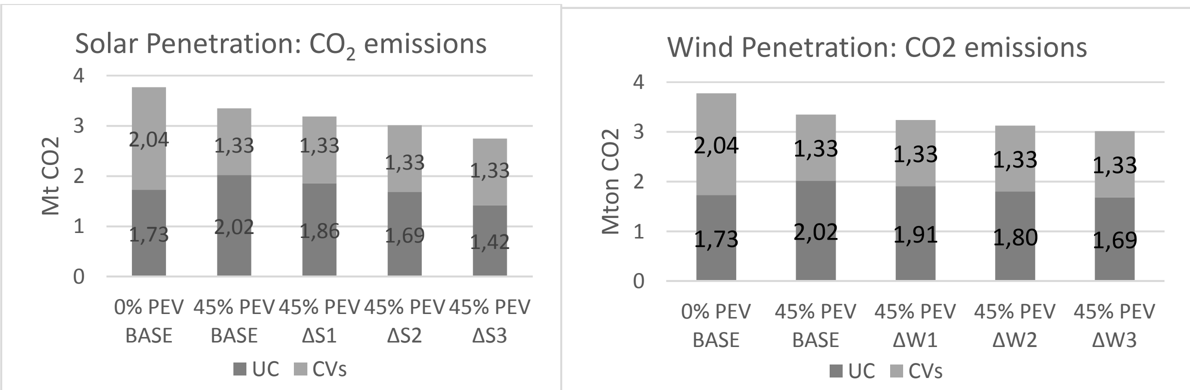


Figure 9: CO_2 emissions for a) solar and b) wind scenarios

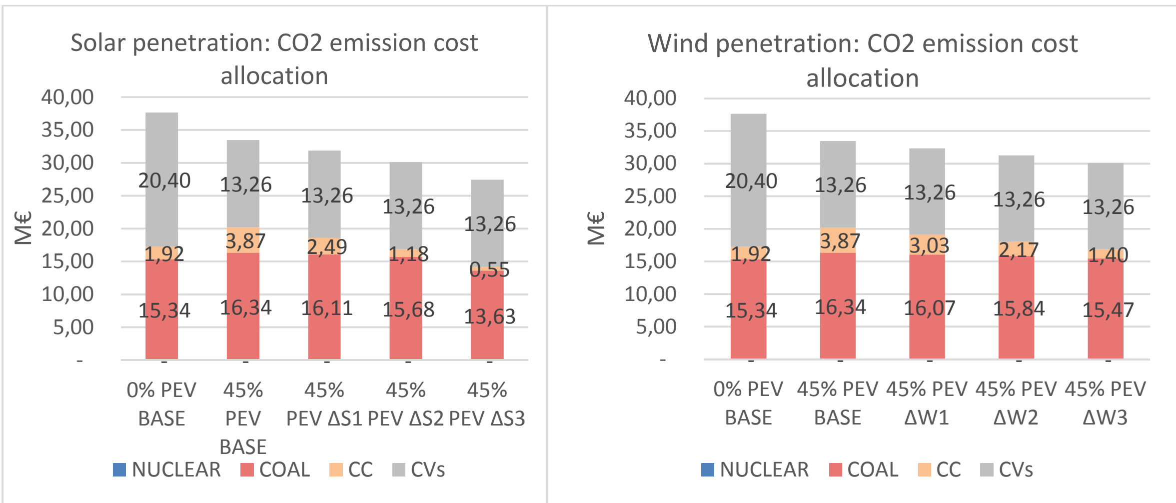
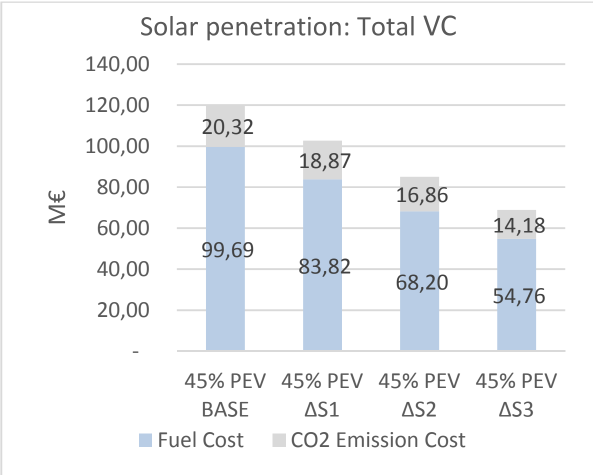


Figure 10: a) CO2 emissions costs allocation for a) solar and b) wind scenarios

Coal plants emissions are much larger, since it is the technology that produces more energy and has larger CO_2emissions, as shown in TABLE II. This implies that the emissions costs are almost hundred percent due to coal plants, being the impact of CC plants negligible. Since the production of coal plants do not change significantly over the different scenarios (they are supplying at almost maximum capacity), CO_2 costs variations depend mainly on the fluctuations of CC production. Since CC plants have much lower emissions, total CO_2 emissions depend mainly on coal plants and thus remain almost constant for most scenarios. Only scenario ΔS3 with a larger reduction of the thermal gap that also reduces coal production shows a more significant CO_2 emissions reduction.

Figure 11 shows the total variable costs for the whole simulated week. The impact of CO_2 emissions cost on the total cost is almost negligible. Indeed, the dispatch is decided mainly by the variable cost of the units, much more significant than emissions costs.



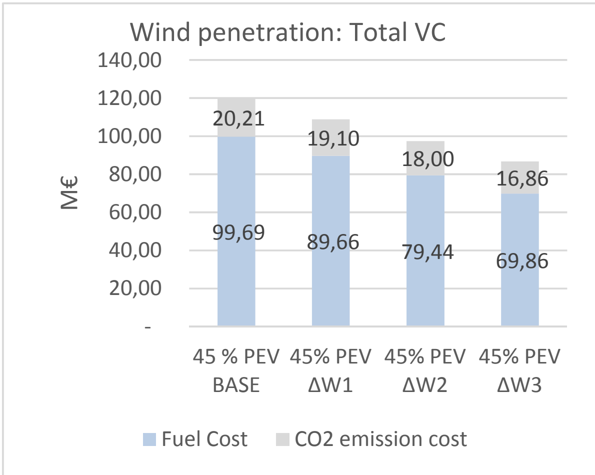


Figure 11: CV vs CO2 costs fora) Solar and b) wind penetration scenarios

3.5 **Electricity price and energy cost**

If the electricity price is set as the dual variable of the energy balance constraint, Figure 12 shows the resulting prices for scenarios ΔW3 and ΔS3 of solar and wind penetration, for a selected day.

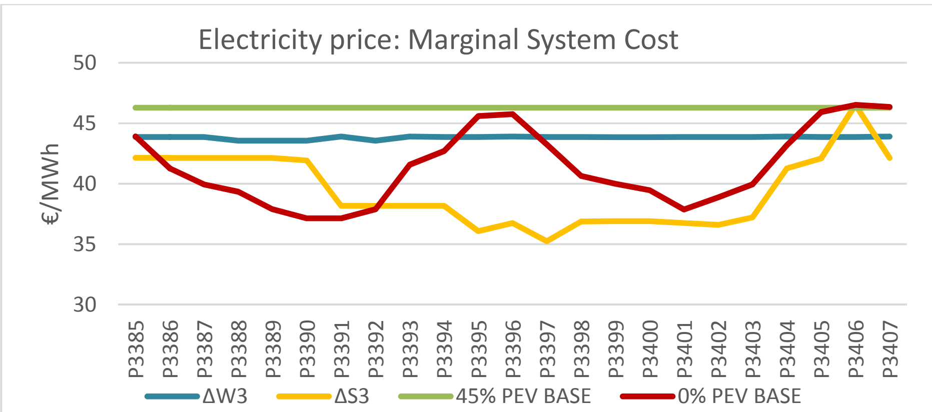


Figure 12: a) Solar and b) wind electricity prices for scenarios ΔW3 and ΔS3

The first think to note is how a large PEVs penetration increases demand but smooth electricity prices making them almost constant. This implies a much better behavior of thermal plants, reducing ramps dramatically. In addition, as can be seen, prices for the solar penetration scenario are lower, but show more variability than wind scenario prices. Prices for the solar scenario become up to 6 €/MWh lower than the base case (with 45% PEV but no additional renewable installed), while prices for the solar scenario are about 2 €/MWh lower than those of the base case. It is also interesting to remark that, at dusk, when solar decreases almost to cero but demand is still high, there are a few hours where solar scenario prices become larger than wind ones, because CC plants are needed to supply the high net demand at these hours.

Figure 12 shows the average cost of the energy (sum of the energy consumed at each hour times the price at this hour divided by the total energy consumed), which corresponds to the average payment for the consumed energy at the wholesale market (ignoring taxes and additional charges).

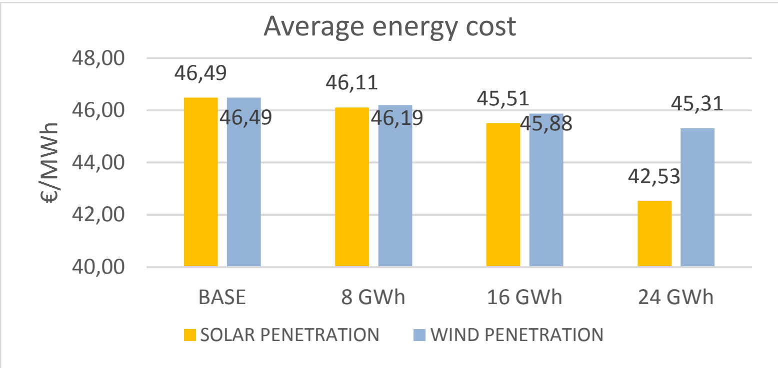


Figure 13: average energy costs for a) solar and b) wind penetration scenarios

As can be seen, the average costs for the simulated week are very similar for both solar and wind penetrations, although they are lower for the solar penetration scenarios since solar generation tends to produce at peak demand hours, and so more expensive thermal units are replaced by solar generation. This effect is particularly relevant for scenarios ΔW3 and ΔS3, where the average cost of the solar scenario energy is around 3 €/MWh lower than the wind one.These results are logically coherent with the prices patterns shown in Figure 12.

3.6 **Total costs analysis**

TABLE IV summarizes all the weekly costs for all scenarios analyzed.

TABLE IV
Total costs for solar and wind scenarios

PEV	**RES pen.**	**Wind/Solar investment (M€/week)**	**Startup and Shutdown Cost (M€)**	**Fuel Cost (M€)**	**CO_2 emission Cost (M€)**	**Production Cost (M€)**	**Total Cost (M€)**	**Energy Cost (M€)**
45%	BASE	-	3,65	99,69	20,21	123,55	123.55	156,97
45%	ΔW_1	11.5	3,55	89,66	19,10	112,31	343.08	150,83
	ΔW_2	23.1	3,55	79,44	18,00	101,00	562.54	132,49
	ΔW_3	34.6	3,39	69,86	16,86	90,11	782.42	120,25
45%	ΔS_1	19.2	3,45	83,82	18,59	105,87	490.48	138,27
	ΔS_2	38.5	3,35	68,20	16,86	88,41	857.64	119,24
	ΔS_3	57.7	3,26	54,76	14,18	72,21	1226.05	95,78

TABLE V looks at the cost increments that take place between each renewable scenario and the base case with 45% PEV and no additional renewable.

TABLE V
Total costs for solar and wind scenarios

PEV	RES pen.	Wind/Solar Investment (M€/week)	Production Cost variation (M€)	EnergyCost variation (M€)
45%	ΔW_1	11.5	-11.23	-6.14
	ΔW_2	23.1	-22.55	-24.48
	ΔW_3	34.6	-33.43	-36.72
45%	ΔS_1	19.2	-17.68	-18.70
	ΔS_2	38.5	-35.14	-37.73
	ΔS_3	57.7	-51.34	-61.19

As can be seen, investment costs for both solar and wind penetration scenarios are not totally compensated by the production cost reduction, given the current investments prices, and from a centralized approach. In addition, even if solar generation fits better the demand, with a larger reduction of production costs, its larger investments costs make more profitable wind generation investments, although differences are not very significant. This does not mean that the total benefit obtained for a particular agent investing in renewable and selling the energy at the marginal price could not be positive. However renewable investments decrease the marginal price (Figure 12) and so all the technologies' profit, and in particular, thermal plants profits.

4 CONCLUSIONS

This paper presents a detailed analysis of the behavior of the power system when 45% of PEV penetration is combined with different solar and wind penetration amounts. Thermal dispatch, reserve allocation, prices, emissions and emission costs, and total system cost including investments are reviewed.

Although this analysis is a simplified approach and considers only a particular week (authors are extending the analysis to the whole 2011 year), several conclusions can be drawn from the results:

- The first thing to note is that PEV penetration increases electricity demand. However, if PEVs charge is allocated optimally, thermal plants production is significantly smoothed and prices become almost constant. The fact that PEVs consumption can be optimally allocated has a beneficial impact on the final production costs, leading to an almost flat net demand.
- Even if solar and wind generation have very similar capacity factors, solar penetration leads to larger prices variability, but since its production concentrates on peak hours, the resulting production cost is lower than for wind penetration.
- Since current solar investments costs are larger than wind ones, wind penetration is more profitable in term of total system costs. Neither solar nor wind penetration are profitable for the system from a centralized point of view, due to its large investments cost that do not totally compensate the corresponding production cost decrement. However grid parity

is almost reached if no additional costs such as reserve requirements or unbalances are assigned to these technologies.

- The impact of the renewable generation on CO_2 emissions is not very significant under the costs scenarios analyzed. Indeed large PEVs penetration increases the thermal gap so much that coal plants are as its maximum production and CC are needed to supply all the demand. Since renewable penetration is only able to reduce CC production, whose emissions are not very significant, final CO_2emissions do not decrease significantly.

The authors are currently extending this analysis to a whole year simulation, to confirm that the conclusions for only one week can reasonably be extrapolated for a whole year.

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200 years diversifying the energy mix? Diversification paths of the energy basket of Portugal, Spain and, other European countries

M. del Mar Rubio-Varas[1] & Beatriz Muñoz Delgado[2]

[1] *Department of Economics, Universidad Pública de Navarra (UPNA)*
Campus Arrosadía, s/n, Pamplona, 31006, Navarra, Spain
mar.rubio@unavarra.es

[2] *Department of Economic Analysis: Economic Theory and Economic History,*
Universidad Autónoma de Madrid (UAM)
Campus Cantoblanco, C/Francisco Tomás y Valiente 5, 28049, Madrid, Spain
beatriz.munoz@uam.es

ABSTRACT

The energy mix is one of the topical issues in energy economics. The changes in the composition of the energy basket in the long run lead to energy transitions. Primary energy substitution models allow addressing these phenomena. However, the diversification paths of the energy mix of different countries in a long term compared perspective have not been studied yet. This paper proposes an indicator, based on the Herfindahl-Hirschman Index, the Energy Mix Concentration Index (EMCI), to quantify the degree of diversification of the primary energy basket of Spain, Portugal and other six European countries over the last two centuries. The results reveal that larger energy consumers required a huge concentration of their energy basket in the 19th century, however, the observed countries had converged to similar levels of diversification of their energy mixes from the second half of the 20th century, and more crucially after the oil crises. For some countries, today's degree of diversification is the largest in their energy histories, but it is not the case for all of them. Our results suggest that small energy consuming countries would be able to achieve higher diversification, and therefore to do a faster transition to a low carbon economy, than large energy consumers.

KEYWORDS: Energy mix, energy transition, energy baskets, energy diversification.

1 INTRODUCTION

The energy mix is crucial to determine important aspects of energy economics such as the energy efficiency, energy intensity or the carbon intensity of a country. The alterations in the composition of the energy basket in the long run define the concept of energy transition(s).[1] The shape and pace of future transitions have been investigated looking at past transitions (Rosenbloom and Meadowcroft, 2014; Steinmueler, 2013; Fouquet and Pearson, 2012; Rubio and Folchi, 2012; Bennet, 2012; Pearson and Foxon, 2012; Allen, 2012).

The diversification of the energy basket per se has not been studied in the long run. We ignore when (or whether) the energy baskets become more diversified, whether the levels of diversification of the energy mix have converged overtime, whether all countries followed a similar paths and whether diversification of the energy basket took place at the same time everywhere. There exists a general intuition about the energy basket becoming more diversified in recent times. This ignores the traditional forms of energy available in the past (draft power, wind, water, firewood), which allowed a variety of energy mixes with large diversification of energy carriers in previous centuries.

The interaction between energy mix and successive energy transitions also requires further investigation. The energy ladder hypothesis, by which countries move to higher quality energy carriers as their income increases, seems to imply a path towards increasing energy mix diversification as countries become richer. Yet it remains unclear whether the energy ladder is a theoretical myth or and empirical truth (van der Kroon et al., 2013). We find different countries' experiences depending, among other things, on their energy endowment (this entails the comparative advantages among the energy carriers are different in every country), and the amount of energy consumed.

The approach of this essay to the evolution of the diversification of energy mix over the long term may be also useful for shedding light to some other crucial questions such as whether was it easier to alter the energy mix in the past or in recent times. In other words, how quickly can the energy mix be altered? Last but not least, shall a country always prefer energy mix diversification to concentration?

A small body of evidence (Marcotullio and Schulz, 2007; Rubio and Folchi, 2012) suggests that countries consuming large amounts of energy behaved differently from small energy consumers in the process of altering their energy baskets –i.e. in their energy transitions. Rubio and Folchi, using Latin American data, showed that small energy consumers had earlier and faster transitions than leading nations. Henriques and Sharp (2015) find also a quick transition to coal in Denmark, a small consumer too. Following this reasoning, the essay departs from the hypothesis that large and small energy consumer's baskets tend to change differently, which in turn will imply that the degree of concentration of the energy mix evolved differently over time depending on the scale of energy consumption.

Energy mix concentration has also become a component of the indicators of energy vulnerability (the higher the concentration, the greater the vulnerability). This explains the recommendations to increase the countries' energy diversification (of energy sources,

[1] Grübler (2004:163) proposes a more complex definition of energy transitions "in terms of three interdependent characteristics: quantities (growth in amounts of energy harnessed and used), structure (which types of energy forms are harnessed, processed, and delivered to the final consumers as well as where these activities take place), and quality (the energetic and environmental characteristics of the various energy forms used).

suppliers and routes), among other strategies, in order to enhance their energy security (IEA, 1993; European Parliament, 2001: 17; European Commission, 2001: 2; Alhajji y Williams, 2003; Blyth and Lefevre, 2004: 7; Escribano, 2006).

In any case, it is worth mentioning energy diversification does not prevent from energy risks to occur, but reduces the level of dependence from each source or supplier, and therefore it provides alternatives to response in case there is any energy carrier/supplier/transition interruption (IEA, 1985: 90) or in the event of a sudden increase in prices (conditioned to fuel substitutability). In sum, when we deal with energy diversification we are dealing with exposure to energy risks and flexibility.

The rest of the paper is organised as follows: the next section explains the data sources and the methodology used, based on concentration measures. The subsequent section focuses on the Energy Mix Concentration Index (EMCI) analysis and the results obtained. The article ends with some concluding remarks.

2 DATA AND METHODS

Some of the longest and more consistent series of primary energy consumption belong to eight European countries, and cover the period 1800-2010, i.e. two centuries. The historical database was developed over the last decade by a number of energy researchers - England and Wales (Warde, 2007), Italy (Malanima, 2006), Netherlands (Gales et al., 2007), Portugal (Henriques, 2011), Spain (Rubio, 2005) and Sweden (Kander, 2002). The results have now been synthesized and the list of countries expanded to include Germany and France in Kander et al. (2014). This makes the database internally coherent, using the same methodologies across countries and energy carriers.

The energy data for these eight countries consider the full set of energies –traditional and modern- and refers to primary energy supply. The database includes food for men and working animals, firewood, traditional wind and water used in wheels and mills, and peat recognised as traditional (also called 'organic') energy carriers. Modern energy carriers refer to the commercial sources developed after the industrial revolution: mineral coal, petroleum, natural gas and the primary forms of generating electricity at heat value-hydroelectricity, nuclear and renewable carriers such as wind power, solar, geothermal, etc.

Widening the scope beyond commercial energy carriers has proven to make important differences interpreting long term trends on most aspects of the relationships between the economy, the environment and the energy consumption (Bartoletto and Rubio, 2008; Bertoni et al., 2009; Gales et al., 2007; Kander, 2005). That is why this essay is restricted to these few countries for which traditional energy consumption has been estimated. Given the importance of traditional energy carriers up to well into the 20th century any attempt to measure the degree of concentration of the energy baskets in the long run without including them will be flawed.

These eight European countries can be grouped into two categories according to their economic and energy use histories. Four of these countries were early comers, both by energy standards –with coal as their dominant energy carrier along the 19th century- and by their economic histories as advanced nations: England and Wales, France, Germany and the Netherlands. The other four countries, situated at the European periphery, are often referred to as latecomers: both energetically –with firewood dominating their energy baskets until the 20th century- and economically: Italy, Portugal, Spain and Sweden.

In order to answer the questions posed in the introduction, some sort of quantitative index of concentration of the energy baskets is needed. In this field, the simplest measure of concentration is the mix share, that is, the percentage of each energy source in the energy matrix. It is worth looking at other disciplines when dealing with diversity and concentration. The deepest research activity on diversity has taken place in the area of mathematical ecology (Stirling, 1999: 37) where the energy economists take the most common concentration indicators[2]: the Herfindahl-Hirschman Index (in ecology, the Simpson Index) and the Shannon-Wiener Index[3].

For this paper the concentration of the energy mix in a given year has been calculated using the Herfindahl-Hirschman Index (HHI) (Hirschman, 1964). First used to calculate the concentration of trade of a given country, the HHI has also been used before on the energy and environmental fields (Sällh et al., 2013; Chandarasupsang et al., 2006; Liston-Hayes and Pilkington, 2004).

For each country, we built a matrix containing the share of each energy carrier in the total energy consumption of every year from 1800 to 2010 –from mid 19th century in the case of Italy, Portugal and Spain- which corresponds to the formula:

$$HHI_t = \sum_i^t p_i^2 \qquad [1]$$

where p_i is the energy share of energy carrier *i*. Smaller values of the HHI indicate greater diversification, with 0 being the minimum concentration and 1 being the maximum concentration.

3 RESULTS AND DISCUSSION

Applying the Herfindahl-Hirschman Index to the composition of the energy mix we obtain the yearly Energy Mix Concentration Index (EMCI hereafter) over the last two hundred years for these eight European countries. The respective EMCI are plotted in Fig. 1 for England and Wales, France, Germany and the Netherlands and in Fig. 2 for Italy, Portugal, Spain and Sweden. The smaller (larger) the EMCI is, the more diversified (concentrated) the energy mix turns out to be. The vertical lines in each country graph mark the year in which the previous prevalent energy carrier gives way to the next dominant carrier, which we identify too. The figures also include an intuitive classification between low, medium and high concentration according to the theoretical distribution of the EMCI, with the lower third of the index been classified as low concentration of the energy mix (i.e. high diversification) and the values falling on the upper third corresponding to high concentration of the energy mix (i.e. low diversification).

The countries in Fig. 1 exhibit some common features for the large energy consumers in Europe. They made an early transition from firewood to mineral coal. In fact, according to these data England and Wales entered the 19th century with coal already as prevalent energy carrier. France, Germany and the Netherlands entered the coal era by mid 19th century. For all of them, the transition from firewood to coal implied an increasingly concentrated energy mix, as coal took larger shares of their energy basket in order to feed their growing energy requirements. These early comers remained under coal dominance for over a century.

[2] A review of non-parametric measures of ecological diversity can be found in Stirling (1999).
[3] An explanation of the strengthens and weaknesses of these indicators can be found in Stirling (1999).

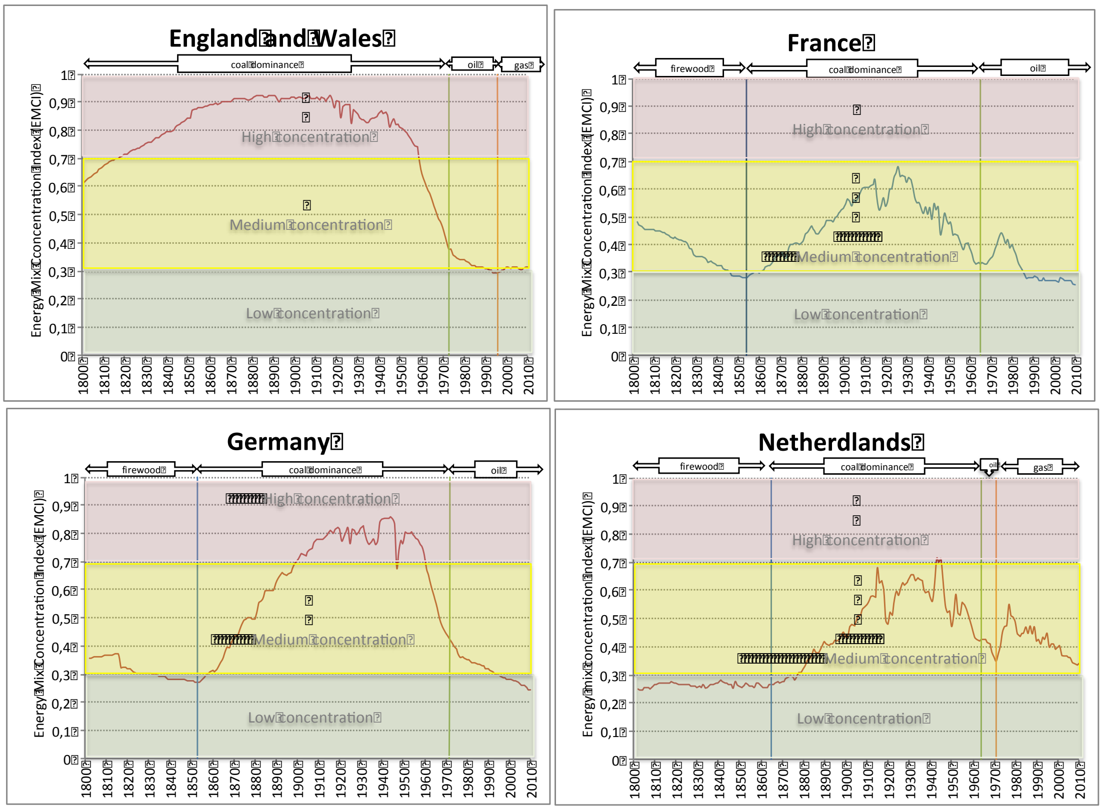

Fig. 1: Energy Mix Concentration Index (EMCI), dominant fuel, and year of transition for 4 European early comers from year 1800 through 2010.

Sources and notes: energy data from Kander et al. (2014), includes pre-modern and modern energy carriers. Energy Mix Concentration Index (EMCI) measured by a Herfindahl-Hirschman Index (HHI). The smaller (larger), the more diversified (concentrated) the energy mix. The vertical lines mark the year in which the previous prevalent energy carrier gives way to the next dominant carrier.

They also share the dates and effects on diversification of the transition from coal to oil. Petroleum became the prevalent energy carrier for these four countries between the late 1960s and early 1970s, right before the oil crisis. The entrance and eventual prominence of oil in their energy baskets implied greater diversification of their energy mix in general terms. For sure, other carriers participated in the diversification of the energy mix over the second half of the 20th century –most notably hydroelectricity, nuclear, and natural gas- but the battle between coal and oil as principal energy carrier prevailed. The shifts in energy consumption patterns and the dominance of one or another fuel are highly conditioned to the countries' energy endowments (e.g. it explains the noteworthy concentration of the energy mix of England and Wales and Germany, based on coal).

The period beginning with the first oil crisis brings some differences across the early comers' energy mixes. While the British Isles and Germany continued to diversify their energy matrixes, France and the Netherlands had a short phase of increasing concentration before exhibiting further diversification that extends to the 21st century. A further difference is that in two cases–England and Wales and most notably the Netherlands- endured a further transition where natural gas replaced oil as the prevalent energy carrier. In fact, the transition to natural gas was relatively fast. In the Netherlands natural gas supplied 50 per cent of total primary energy by 1971, a little bit more than a decade after the discovery of the giant Groningen field in 1959.

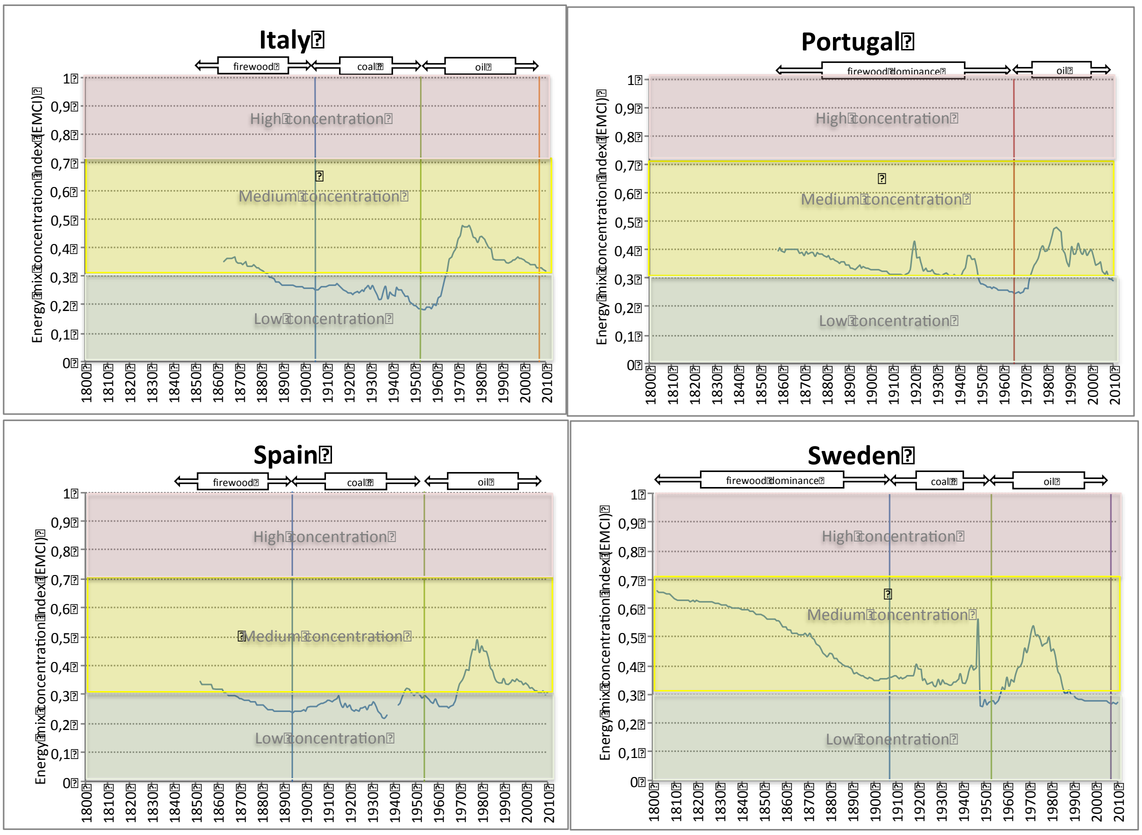

*Fig. 2: Energy Mix Concentration Index (EMCI), dominant fuel, and year of transition for 4 European latecomers from the 1850s to 2010***.**

Sources and notes: energy data from Kander et al. (2014), includes traditional and modern energy carriers. Energy diversification (or concentration) of the energy mix measured by a Herfindahl-Hirschman Index (HHI). The smaller (larger) the more diversified (concentrated) the energy mix. The vertical lines mark the year in which the previous prevalent energy carrier gives way to another carrier.

The latecomer group of European peripheral countries in Fig. 2 share some features of their own. They arrived some 50 years later than the early comer group to the coal era, but by the beginning of the 20th century peripheral Europe had made their transition to coal. Exception made of Portugal, the poorest country of the lot, which took much longer to abandon firewood as predominant fuel and leapfrogged straight into oil by the mid sixties. Coal never dominated the Portuguese energy basket. For the rest of peripheral Europe, coal reigned over the first half of the 20th century but between the mid 1950s and the 1960s the latest, oil become the major energy carrier.

The transition from firewood to coal implied a larger diversification their energy baskets – a smaller EMCI- while the oil supremacy that began in the 1960s conveyed an increasing concentration of their energy mixes reaching maximum EMCI levels just as the oil crises unravelled. The events of the 1970s made evident the need for diversification away from oil, and the four countries pursued energy mix diversification strategies, which were more successful in Sweden than in the Mediterranean countries.

Besides the obvious classification criteria - latecomers' transit to modern energy carriers happened some half a century later than early comer's transition- the differences in the evolution of both groups are striking. Latecomers endured much shorter coal dominance (some 50 years versus over a century of the early comers). Latecomers also shifted earlier to oil as predominant energy carrier –over a decade earlier.

Furthermore, these results show very different diversification paths of the energy baskets of European early comers versus latecomers. The early comers achieved the maximum level of concentration during their coal era somewhere on the first half of the 20th century. The latecomers reached the maximum concentration of their energy baskets in the early days of the oil dominance, right before the oil crisis of 1973. These two maximums are not only distant in time and predominant fuel, but also differ in their magnitude. Early comers maximum EMCI almost doubles the maximum EMCI of latecomers. In other words, early comers endured much more concentrated energy baskets than latecomers would ever do.

Table 1: Average level of energy consumption, energy consumption per capita and Energy Mix Concentration Index (EMCI) of European early comers vs latecomers 1870-2010 (selected periods)

	Total average energy consumption (PJ)		**Total average energy consumption per capita (GJ per habitant)**		**Average EMCI**	
	Early comers	*Latecomers*	*Early comers*	*Latecomers*	*Early comers*	*Late comers*
1870-1913	9,336	1,300	74.8	21.7	0.73	0.29
1920-1938	14,663	1,956	95.8	25.7	0.77	0.25
1950-1973	23,029	5,215	128.1	52.7	0.54	0.29
1980-2010	31,144	12,700	151.1	109.5	0.27	0.31

Sources and notes: energy data from Kander et al. (2014), includes traditional and modern energy carriers. Weighted average over each of the periods. Early comers refer to the average of England and Wales, Germany, France and the Netherlands. Latecomers refer to Italy, Portugal, Spain and Sweden.

As Table 1 reflects, the path of the two groups also varies. Taking the long-term perspective, the early comers followed a path of increasing diversification, achieving by 2010 their most diversified energy basket of the past two hundred years –except for the Netherlands. This is not the case for the latecomers –except Sweden- who enjoyed much more diversified energy mixed in the past. Thus, the early comers reduce the concentration level of their energy mixes by 63% from the first period to the most recent one, while the latecomers remain more or less the same, on average.

Taking into account the size of the countries in energy terms, the level of concentration/diversification reacted differently to new technologies in large and small energy consumers. While coal adoption contributed to increase the energy mix concentration of the large energy consumers (England and Wales, Germany, France and the Netherlands) during the19th century and the early years of the 20th century, the diffusion of coal did actually imply a larger diversification of the energy basket of the small consumers (Italy, Portugal, Spain and Sweden). The arrival of oil predominance over the 1950s and 1960s also implied opposite results for the diversification of the energy mixes. Oil predominance had the effect of increasing concentration of the energy basket of the small consumers, but reducing the level concentration of the energy basket of the large energy consumers. Towards the end, however, when the levels of energy consumption per capita levelled out, the concentration index of both groups also equalised in the frontier between low and medium concentration of the energy mix.

4 CONCLUSIONS

We find that countries had converged to similar levels of diversification of their energy mixes only from the second half of the 20th century and more crucially after the oil crises– that is only for the last quarter of the period under consideration. However, the path towards today's level of diversification of the energy mix diverged over the past 200 years. While the large energy consumers came from above (increasing their diversification levels) while latecomers –which tended to be also smaller energy consumers for equivalent levels of income- enjoyed historically lower levels of concentration in their energy mixes. For some countries, today's degree of diversification is the largest in their energy histories but it is not the case for all of them.

We also find that the alteration of the energy basket took far more time in the 19th century, and that concentration levels of early comers were far higher than the concentration levels of the energy baskets of the late comers.

Finally the question about size remains part of the explanation behind the differences observed: consuming large amounts of energy in the 19th century required a huge concentration of the energy basket on coal consumption. Smaller consumers could get by with a variety of pre-modern sources to add to a modest consumption of coal. Also when the latecomers required larger amounts of energy by the mid 20th century the array of available energy technologies had widen considerably.

Rubio and Folchi and Marcotulio and Sulzt advanced that large and small energy consumer –i.e. developed and underdeveloped countries- may not behave likewise in terms of their energy transitions. The evidence we present here points in the same direction: size matters at the time of altering the level of concentration of the energy mix –it was more difficult for large consumer than for small consumers to achieve diversification. This has to do in part with the amount of fixed capital invested and the difficulties to alter the energy matrix when the sunk costs matter a great deal. Energy related capital (from energy generating, distributing to energy consuming capital) tend to be long-term investments with long amortization periods. The larger the amount of energy consumed the more vested capital related to energy. Small energy consumers have the advantage conferred by minimum pre-existing investment and the opportunity of leapfrogging in the energy ladder (as shown by the Portuguese case above).

Would diversification be the definitive trend in the future? It is desirable above all things? Imagine we could get hold on a Nikola Tesla's type of ubiquitous free energy present in the ether around us. Then it would make sense to switch to it swiftly, giving up lower quality more expensive energies and concentrate as much as possible on this new free/safe/clean energy. In such scenario, our results imply that the small energy consuming countries will be able to do a faster transition than the large energy consumers.

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Effects of the Spanish environmental policies on photovoltaic energy production

Fernández González, Raquel[1]; Álvarez Feijoo, Miguel Ángel[2]; Arce Fariña, Elena[3]; Suárez García, Andrés[4].

[1]*Universidad de Vigo; Grupo ERENEA, Vigo, Spain, raquelf@uvigo.es*
[2]*Centro Universitario de la Defensa (CUD), Marín, Spain, alvarezfeijoo@cud.uvigo.es*
[3]*Centro Universitario de la Defensa (CUD), Marín, Spain, elena.arce@cud.uvigo.es*
[4]*Centro Universitario de la Defensa (CUD), Marín, Spain, asuarez@cud.uvigo.es*

ABSTRACT

The financial incentives given by the Spanish government were one of the key factors for the photovoltaic installations development. Their high profitability and apparent reliability guaranteed by law decrees attracted a lot of investors searching for promising investments in a crisis context. In only two years, 2007 and 2008, the production of photovoltaic panels tripled.
The great success of the initiative produced a big spending of public funds. Because of the above, the Spanish government reduced the bonuses and therefore, the profitability of the investments. The backdated nature of the package adopted had a negative impact in the photovoltaic sector, diminishing the relative importance of the renewable energies in the Spanish energetic mix.
In this work, it is analyzed the Spanish energetic regulatory framework relative to the photovoltaic energy. Different cases and scenarios are studied, discussing the Spanish market response to the Spanish legislative changes. Analytics tools are employed to characterize the market behavior.

KEYWORDS: Photovoltaic energy, regulation, energy markets, environmental policy, investment issues, financial incentives.

1 INTRODUCTION

In the last decades, the renewable energy sector has become one of the best investment sectors of the Spanish economy. Although different issues have caused its transformation, the energetic regulatory framework was the most crucial one. Its financial incentives tripled the installed Spanish photovoltaic power in the short period of three years (Mir, 2012). At the end of 2008, Spain was one of the greatest photovoltaic energy producer in Europe, behind only of Germany and Italy (Fig. *1*).

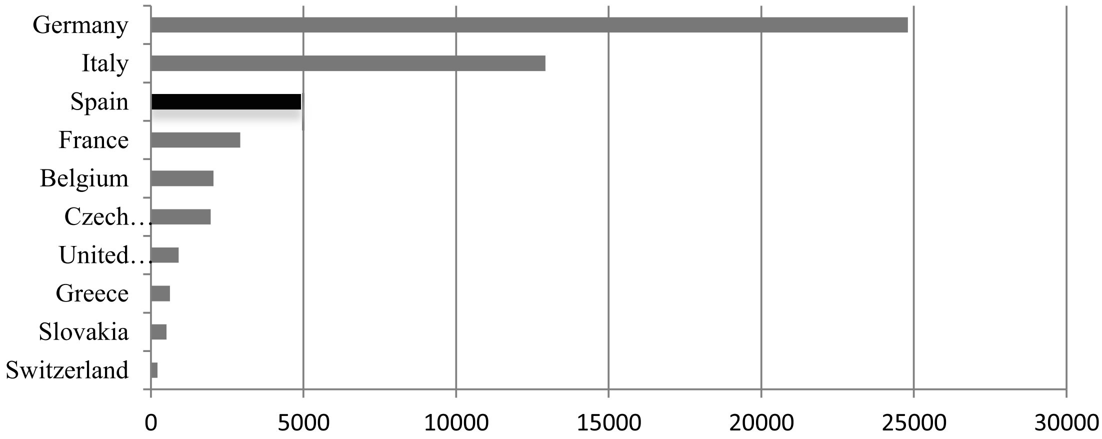

Fig. 1 European countries with the highest proportion of installed photovoltaic capacity installed (MW). 2011. (UNEF, 2013)

The incentive framework had negative effects in the investors in the medium term. The high bonus in the photovoltaic market led an opportunistic behavior. In 2010, a new package was legislated, decreasing the cash incentive and increasing the legal and administrative costs for the photovoltaic facilities. Also, the bureaucratic process for establishing new photovoltaic ventures was slowed down, placing Spain in the worst European country to create a new photovoltaic venture from the time point of view (Fig. 2). Furthermore, the downsizing package had a backdated nature, modifying the profits and the amortization period of the existing photovoltaic installations. Finally, the initial incentive framework turned into an adverse scenario for the promotion of the photovoltaic installations.

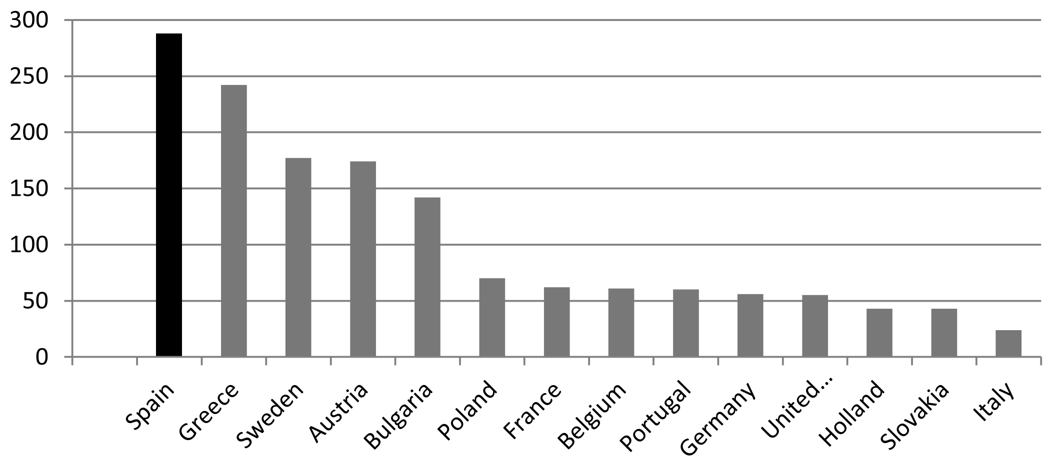

Fig. 2 Weeks required to develop a photovoltaic project in the EU. 2014. (Own elaboration based on UNEF, 2015)

2 SPANISH LEGISLATIVE FRAMEWORK FOR DEVELOPPING THE PHOTOVOLTAIC ENERGY

The Royal Decree (RD) 2818/1998 established the basis for the development of the renewable energies. The previous existing energetic regulatory framework was only focused on the use of the fossil combustibles. The Law 54/1997 channeled the development of the energy sector through the use of renewable energies (i.e. the 12% of the energy primary consumption has to be done in renewable manner at the end of 2010 (Espejo, 2004)). Afterwards, there were various RD consolidating the road mapped by the RD 2818/1998. The RD 1432/2002, approved the 27th of December of 2002, stated a methodology for calculating the electric price. The RD 436/2004, approved the 12th of March of 2004, had the objective the unification of the previous legislation about energy generation under special regime with the new one. It established a new legislative and economic framework, paying special attention to the energy generation facilities. Summarizing, the RD 2818/1998, also known as the Renewable Energy Development Plan (*Plan de Fomento de las Energías Renovables,* in Spanish), developed the Spanish energy sector placing the renewable energies as a priority.
The pricing system Based both on RD 2818/1998 and RD 1432/2002 define two forms of renewable energy reward, but, in practice, only one of which is the overwhelming majority: The owner of the energy renewable facility could trade all or only the surplus of its energetic production with the electricity companies, receiving a part of the reference electricity price (*Tarifa Eléctrica Media o de Referencia, TEMR*) determined by the Spanish government. Therefore, there was only a minor margin of negotiation between the controllers and controlled. Additionally, there were less transaction fees because their immobility and predictability. In addition to this, the owner would receive an incentive for being part of the electricity market when a set of requirements were accomplished. Before the RDs a photovoltaic facility likely to be subsidized must have an installed power below 5 kW. Because of them, the upper limit was set to 100 kW (Espejo, 2004).
A new institutional modification was introduced by Royal Decree 661/2007. Although this Royal Decree maintained the possibility of choice between the two types of sale of energy, greater innovation was to create a system of "floor and ceiling." This method took as reference price the sum of electricity price plus the financial incentives set. But it also established maximum and minimum values in the price, and therefore, the maximum and minimum amounts to be received were set by this range.
The application of this system was planned for the lifetime of the installation, even though the aid would be reduced gradually. Every year until 2010, the quantities and limit values were revised taking into account the CPI. From 2010, the updating of the limits was held every four years (del Rio, 2009).
This modification also limited the installed power, up to a maximum of 371 MW, with a revision of rates when 85% of the maximum value of installed power was reached. When this revision stars, it would be entailed a maximum period of this remuneration system would remain in effect, always more than one year. And at the moment that the extra period ends, the rate to be received would be the final price of the wholesale electricity market, which meant very substantial reduction compared to previous earnings (Mir, 2012).
It is important to point out that in the year before the entry into force of the RD 661/2007 photovoltaics had grown about 204 MW. In June 2007, already it had a production close to 71% of the limit value set (371MW) (Fig. 3).

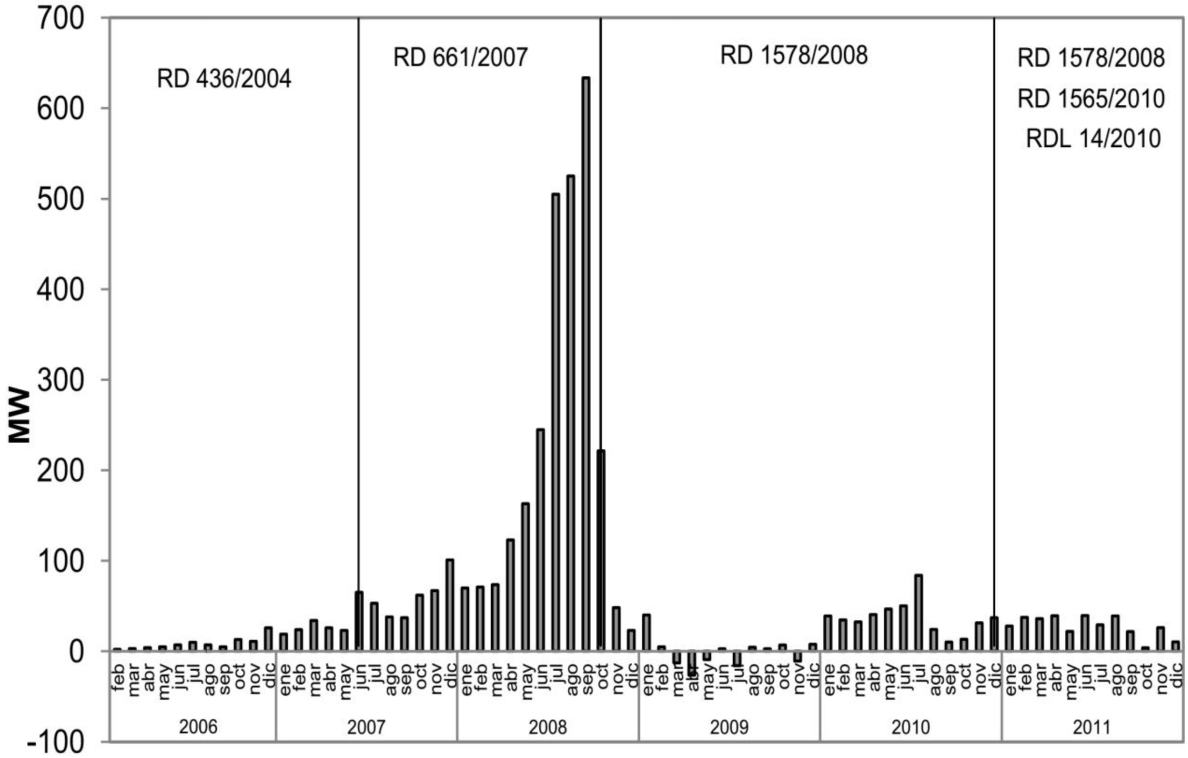

Fig. 3 New mmonthly photovoltaic capacity installed from 2006 to 2011 and current regulation (Mir, 2012)

Under this institutional framework, photovoltaic solar power was increasing exponentially, particularly noticeable the middle months of 2008. According to the data of the National Energy Commission of Spain (*Comisión Nacional de la Energía, CNE*) in October 2007 the power installed was 521 MW, more than 40% more than the estimated value. In Fig. 2, it can be seen the percentage increase over previous year, with sharp variations in the years 2006, 2007 and 2008.

One of the main effects of this institutional scope (Royal Decree 661/2007) was historical change in the photovoltaic energy production in Spain, with consequent economic effects for the public sector. Consequently, and due to these effects, the Spanish government initiated a legislative process which ended with a new scenario of reduction and settlement of the financial incentives.

Royal Decree 1003/2010 (2010), adopted on August 5, 2010, regulated the equivalent premium clearance of the plants for generating electricity with photovoltaic technology in special regime. This new regulation restricted the perception of equivalent premium by the date in which the plant was put into operation.

And those plants that, even realizing the premium, could not be completed before the entry into force of this new royal decree, they could renounce to it voluntarily. Cases where the legislation does not require to return premiums received irregularly (ASIF, 2011).

Subsequently, Royal Decree 1565/2010 was approved in November 2010. It states that plants 2 MW or more were required to withstand voltage dips by Operating Procedure 12.3 (Fig. 4).

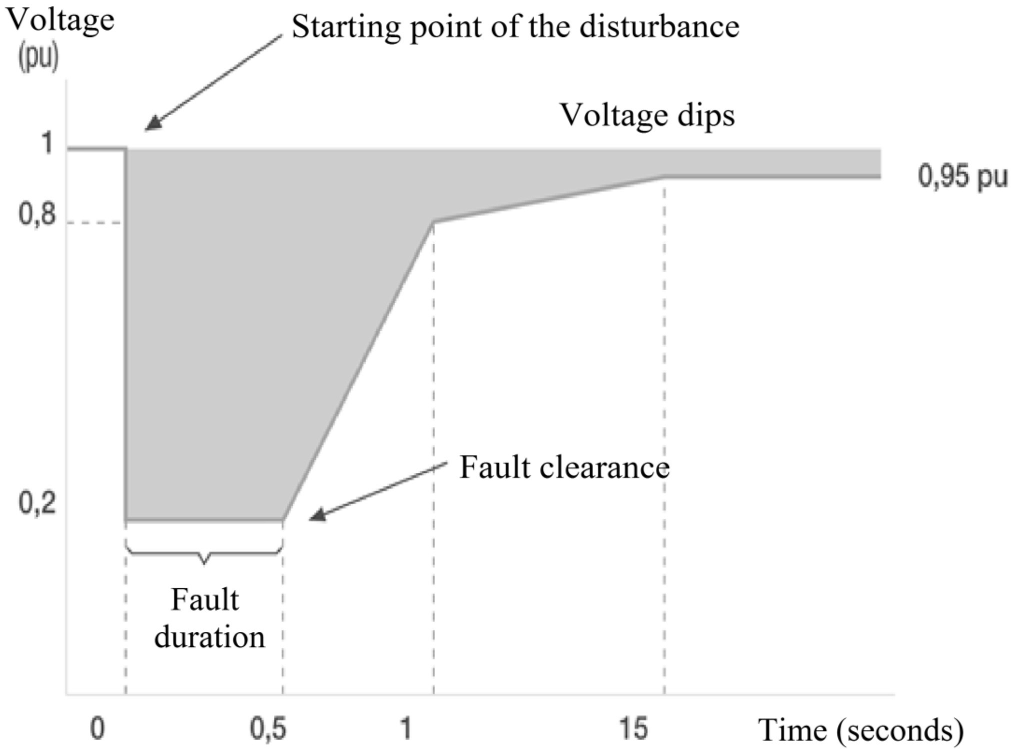

Fig. 4 Operating procedure 12.3 requirements to respond to voltage dips. (BOE. November, 23 2010)

Royal Decree-Law 14/2010, of 23 December, established urgent measures for the correction the tariff deficit in the electricity sector. These measures adopted further reduce the profitability of the investment in photovoltaics. One of those measures incorporated a toll access to the electrical network for electricity producers (0.5 € / MW), which means, for example for installation in buildings, a decrease in revenues of 0.3%, and for ground-mounting power plants a decrease of 0.2% (ASIF, 2011).
However, the most controversial measure for the photovoltaic industry was the reduction of the equivalent operating hours, benefiting from solar tariff. There were two types of time restrictions:

1) The first one divides the country into five climatic zones as was specified in the RD 314/2006. For each area, a limit of equivalent hours for which the facilities will receive premium is set. Fig. 5 shows the different climatic zones and time restrictions.

Fig. 5 Climate zones of Spain. (ASIF, 2011)

Table 1. Limits of hours to receive premiums (RD-L 14/2010)

Technology	Zone I	Zone II	Zone III	Zone IV	Zone V
Fixed facility	1232	1362	1492	1632	1753
Single-axis solar tracking installations	1602	1770	1940	2122	2279
Double-axis solar tracking installations	1664	1838	2015	2204	2367

Source: BOE. December, 24 2010

This resulted in a decrease in the price of photovoltaic panels and an increase in the number of plates in order to increase the peak power (table 2). The government sought to eliminate these practices by introducing a limit of paid hours (ASIF, 2011).

Table 2. Time limitation for facilities covered by RD 661/2007. Period 2011-2013

Technology	Reference equivalent hours / year
Fixed installation.	1.250
Installation with 1-axis tracking.	1.644
installation with 2-axis tracking.	1.707

Source: BOE (Official State Bulletin)

2) The second time restriction (RDL 14/2010) was implemented in the facility to which he applied the RD 661/2007 for the years 2011, 2012 and 2013. This meant that producers had difficulty cover the funding received. In addition, most solar farms had not been paid in full. Thus, many owners were forced to renegotiate its debt.

3 THE IMPACT OF THE CHANGE IN THE GOVERNMENT REGULATIONS REGARDING PHOTOVOLTAIC INDUSTRY

The approval of the RD 661/2007 marked an important step in the growth of photovoltaics in Spain (Fig. *6*). In just one year (2007 to 2008) the power generated by the solar panels grew by more than 300%. The economic crisis and the need to adjust public spending caused premiums reductions. Thus, investors perceive that the sector is legally unsafe. To this must be added the poor compliance with legal standards adopted. This paradigm shift resulted in the change of photovoltaic market orientation.

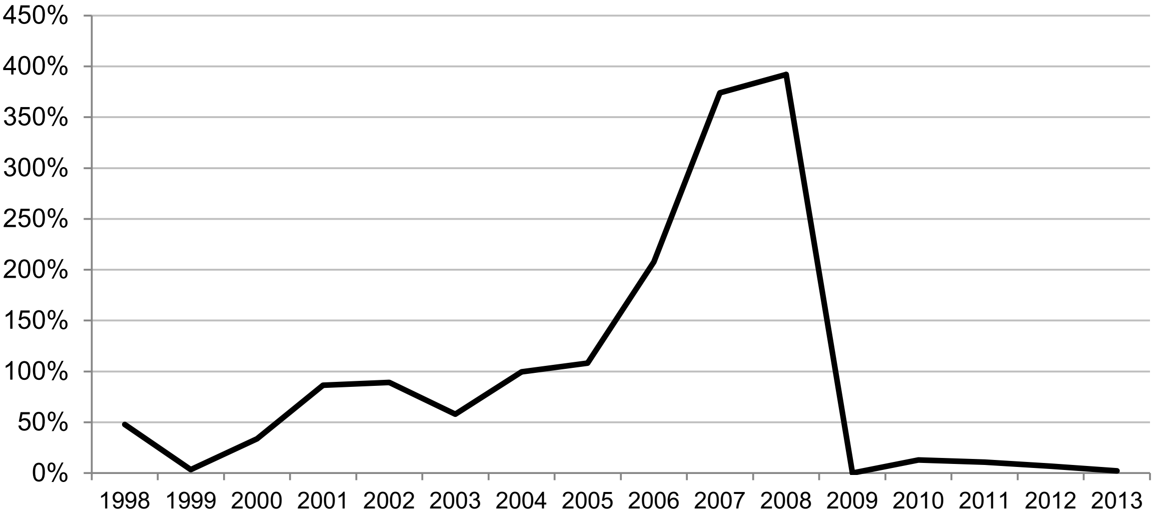

Fig. 6 Photovoltaics: Power increase over the previous year. (UNEF, 2013)

The rates solar energy decreased with respect to the Royal Decree 413/2004 of 2004 (Fig. 7). The facilities with a capacity less than or equal to 20 kW are assigned a price of 0.32 € / kWh; while systems with higher power are assigned a price of 0.34 € / kWh. In 2004 most of the facilities were assigned a price higher than 0.40 € / kWh. Because the price of solar panels fell in 2008, the profitability of facilities was hardly reduced (UNEF, 2013).

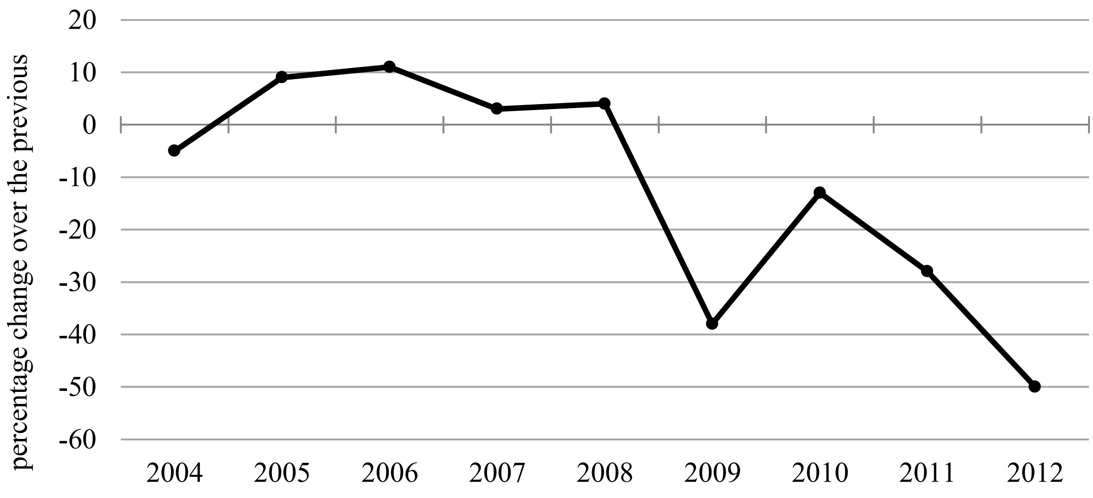

Fig. 7 Evolution of the price of photovoltaic modules (%) (UNEF, 2013)

The labor sector was also affected by the change in energy policy (Fig. *8*). Whereas global level photovoltaics ranks first in the ranking of job creation in the sector of renewable energies, in Spain between 2008 and 2012 23,700 jobs were destroyed.

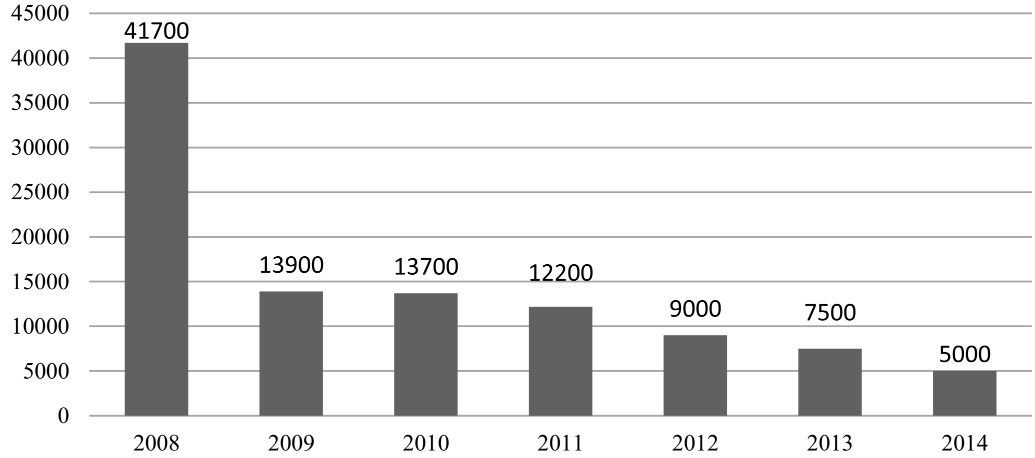

Fig. 8 Direct jobs created in the solar photovoltaic sector (UNEF, 2015)

4 CONCLUSIONS

The Spanish economy is characterized by a heavy dependency on fossil fuels. This fact has implied an important political and academic debate on how best to improve the Spanish energy model and its future possibilities. The Spanish government, especially since 2007, developed a policy of premiums for the installation and operation of solar PV which led to an accumulated power capacity of 4,651 MW until 2014. However, the Spanish energetic regulatory framework and incentive policies for the sector did not result in stability between 2007 and 2014; quite the contrary, there was a change in policy premiums that governments applied to photovoltaics.

Legal changes caused the photovoltaic energy worsens their position with regard to other energies. The number of jobs, both direct and indirect, decreased. Moreover, bureaucratic administration costs of a photovoltaic company increased both in cost and time. Last and foremost, in Spain the growth of photovoltaic power output has stagnated since 2009; and all this is taking place in a global context where photovoltaic solar energy is reaching new growth world record every year.

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R.D. 436/2004, de 12 de marzo, por el que se establece la metodología para la actualización y sistematización del régimen jurídico y económico de la actividad de producción de energía eléctrica en régimen especial. (BOE núm. 75, 27 de marzo de 2004).

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Market-based Instruments in a growth model with Dirty and Clean Technologies

Mónica Meireles[1], Isabel Soares [2], Oscar Afonso[3]

[1] Departamento de Economia – ISCTE-IUL – Lisbon University Institute and BRU-IUL, Av. Forças Armadas, Lisboa, Portugal, monica.meireles@iscte.pt
[2] Faculdade de Economia – Universidade do Porto and CEF.UP, R. Roberto Frias, Porto, Portugal, isoares@fep.up.pt
[3] Faculdade de Economia – Universidade do Porto and CEF.UP, R. Roberto Frias, Porto, Portugal, oafonso@fep.up.pt

ABSTRACT

The Intergovernmental Panel on Climate Change has stated that carbon dioxide (CO_2) concentrations in the atmosphere have been increasing significantly over the past century, compared to the rather steady level of the pre-industrial era. Among the many human activities that produce Greenhouse Gases (GHGs), the use of energy represents by far the largest source of emissions. Since "eco-friendly" technologies enhance the environmental sustainability by inducing more ecological goods production, through low-carbon technologies, attention should be addressed to technological knowledge to reduce these emissions.

In line with this thought, this paper develops a dynamic general equilibrium growth model with endogenous skill-biased technological change to study the contributions of environmental policies in producing relatively more ecological goods, with fewer CO_2 concentrations.

This model is based on Schumpeter´s notion of creative destruction, the competitive process by which firms are constantly looking for new ideas and innovations that will make rival's ideas obsolete. In recent years, the economic and financial crises have changed consumers' behavior. Some studies have found that during recession periods consumers switch a significant amount of expenditures towards essential goods and lower priced goods. As a result, we will assume that consumers are indifferent between dirty and ecological goods, as their main interest is surviving to uncertain future conditions rather than taking into account ecological concerns. This work relates to papers that analyze the environmental policy using endogenous growth models focused on the direction of technological change. However, in contrast to these works, our study stresses the price channel role in directing R&D towards the higher priced good. By solving the transitional dynamics numerically and by removing the scale effects, it is shown that, through the price channel, when green firms and green research are supported by policy and/or dirty activities are taxed, technological progress leads to relatively more production of ecological goods and environmental quality improvements.

KEYWORDS: Environmental Policy, Technological Change, Endogenous Growth

1 INTRODUCTION

The Intergovernmental Panel on Climate Change has stated that carbon dioxide (CO_2) concentrations in the atmosphere have been increasing significantly over the past century, compared to the rather steady level of the pre-industrial era. Among the many human activities that produce Greenhouse Gases (GHGs), the use of energy represents by far the largest source of emissions (IEA, 2014). Since "eco-friendly" technologies enhance the environmental sustainability by inducing more ecological goods production, through low-carbon technologies, attention should be addressed to TK to reduce these emissions.

In line with this thought, this paper develops a dynamic general equilibrium growth model with endogenous skill-biased technological change to study the contributions of environmental policies to produce relatively more ecological goods, with fewer CO_2 concentrations.

This model is based on Schumpeter´s notion of creative destruction, the competitive process by which firms are constantly looking for new ideas and innovations that will make rival's ideas obsolete. In recent years, the economic and financial crises have changed consumers' behavior. Some studies (e.g., McKenzie et al, 2011 and Kaytaz et al, 2014) have found that during recession periods consumers switch a significant amount of expenditures towards essential goods and lower priced goods. As a result, we will assume that consumers are indifferent between dirty and ecological goods, as their main interest is surviving to uncertain future conditions rather than taking into account social or ecological concerns. This work relates to papers that analyze the environmental policy using endogenous growth models focused on the direction of technological change (e.g., Acemoglu et al. 2011; Grimaud et al., 2008; Hart, 2008; Ricci, 2007). However, in contrast to these works, our study stresses the price channel role in directing R&D towards the higher priced good. Three productive sectors are considered: the final goods (FGs), the intermediate goods (IGs) and the research and development (R&D). FGs can be produced by ecological or dirty technology, i.e., FGs can be produced either by more advanced and quality improved renewable technologies or by less advanced and less quality improved technologies. Firms producing with ecological technology can only use non-polluting IGs and skilled-labour contributing to reduce pollution. Those producing with dirty technology can only use polluting IGs and unskilled-labour contributing to increase it. The quality of the IGs is raised by (vertical) innovations resulted from R&D.

The remainder of the paper is organised as it follows. Section 2 presents the model. Section 3 analyses the steady-state equilibrium. Section 4 studies the transitional dynamics and proceeds to some sensitive analysis. Section 5 concludes.

2 THE MODEL

Following Acemoglu et al. (2001), Barro et al. (2004) and Meireles et al. (2012), each perfectly competitive FG $n \in [0,1]$ production is given by:

$$Y_n(t) = \left\{ A_D \left[\int_0^J \left(q^{k(j,t)} x_n(k,j,t) \right)^{1-\alpha} dj \right] \left[(1-n)\, d\, D_n \right]^{\alpha} + A_E \left[\int_J^1 q^{k(j,t)} x_n(k,j,t)^{1-\alpha} dj \right] \left[n\, e\, E_n \right]^{\alpha} \right\} \tag{1}$$

(i) A is the exogenous productivity level reflecting the dirty technological environment (A_D) or the ecological technological environment (A_E); (ii) $x_n(k,j,t)$ are IGs adjusted by the highest environmental quality, $q^{k(j,t)}$ with $q>1$, obtained by each successful R&D; (iii) $j \in [0, J]$ is for dirty IGs (D-IGs) and $j \in]J,1]$ is for ecological IGs (E-IGs); (iv) E and D are the skilled and the unskilled labour; (v) $\alpha \in]0,1[$ and (1-α) indicate the labour and the IG shares; (vi) $e>d\geq 1$ guarantees an absolute productivity advantage of E over D; (vii) n and (1-n) assure that E is relatively more productive in producing FGs indexed by larger n, while D is relatively more productive in producing FGs indexed by smaller n. This implies that, in equilibrium, there will be a threshold FG $\bar{n}\in[0,1]$, such that only dirty (ecological) technology will be used to produce FGs indexed by $0\leq n\leq \bar{n}$ ($\bar{n}<n\leq 1$):

$$\bar{n} = \left\{ \left[\left(\frac{A_E}{A_D} \right)^{1/\alpha} \frac{e}{d} \frac{E}{D} \frac{Q_E}{Q_D} \right]^{1/2} + 1 \right\}^{-1} \tag{2}$$

$$Q_D(t) \equiv \int_0^J q^{k(j,t)(1-\alpha)/\alpha}\, dj \text{ and } Q_E(t) \equiv \int_J^1 q^{k(j,t)(1-\alpha)/\alpha}\, dj \tag{3}$$

The aggregate quality indexes in (3) evaluate the technological knowledge (TK) and the ratio $Q_E/Q_D=B$ measures the (ecological) TK bias. Equation (2) represents a "proxy" for the environmental quality. Small $\bar{n}$ means a relatively higher level of ecological goods production and thus, a better environmental quality and vice-versa.

All resources, Y, can be consumed, C, used in the IGs production, X, or directed to R&D, RS:

$$Y(t) = X(t) + RS(t) + C(t) \tag{4}$$

Unlike FGs, IGs are provided by a monopolistic firm whose production requires a start-up cost of R&D that is recovered by a patent law. Since IGs employ FGs, the marginal costs (MC) of both IGs and FGs are equal (MC=1). Since consumers are assumed to be indifferent between ecological or dirty goods, firms will not have the incentive to produce relatively more ecological goods. Hence, they will produce according to their maximum profits and the environmental quality may fall below a critical threshold. In this context, government needs to encourage ecological goods production to decrease GHGs emissions. In the literature, there is a conventional wisdom that, from an efficiency perspective, market-based instruments are preferred over command-and-control instruments (Baumol et al., 1994). Furthermore, they are believed to be more effective in inducing technological change as they offer a permanent incentive to use lesser environmental commodities.

Assuming that government can subsidise the E-IG and tax the D-IG, the MC after a subsidy or tax is ($MC+\varphi_x$), where φ_x denotes subsidies ($-s_x$) or taxes (τ_x). Thus, the profit maximization price of the IG firms yields:

$$p = (1+\varphi_x)/(1-\alpha) \tag{5}$$

and the limit pricing used to capture the whole market is:

$$p = q(1+\varphi_x), \text{ where } (1+\varphi_x)<q(1+\varphi_x) \leq [(1+\varphi_x)/(1-\alpha)] \tag{6}$$

In turn, the price indexes ratio of ecological and dirty FGs is:

$$p(t) = p_E(t)/p_D(t) = [\bar{n}(t)/(1-\bar{n}(t))]^{\alpha}, \begin{cases} p_D = p_n(1-n)^{\alpha} = \exp(-\alpha)\bar{n}^{-\alpha} \\ p_E = p_n n^{\alpha} = \exp(-\alpha)(1-\bar{n})^{-\alpha} \end{cases} \tag{7}$$

Small $\bar{n}$ implies more FGs produced with ecological technology and hence, a small relative price of these goods. Thus, the demand for E-IGs is low, discouraging R&D that improves their environmental quality. Thus, labour and environmental quality levels affect the R&D direction through the FG price channel (e.g. Acemoglu et al., 2002).

The incentive to support R&D relies on the expected present value of profits flow:

$$V(k,j,t) = \Pi(k,j,t)/[r(t)+pb(j,k,t)] \tag{8}$$

The denominator is the interest rate plus the Schumpeter's creative destruction rate. R&D improves IGs and, hence, the quality indexes (3), while creatively destroying the previous profits Following Aghion et al. (1992), the instantaneous probability – or the Poisson probability distribution - of a successful innovation is given by:

$$pb(k,j,t) = rs(k,j,t)\, \beta q^{k(j,t)}\, \xi^{-1} q^{-(1/\alpha)\, k(j,t)} M^{-1} \tag{9}$$

(i) $rs(k,j,t)$ is the flow of FGs devoted to R&D; (ii) $\beta q^{k(j,t)}$, $\beta>0$, is the positive learning effect of accumulated TK from past successful R&D; (iii) $\xi^{-1} q^{-(1/\alpha)\, k(j,t)}$, $\xi>0$, is the adverse effect caused by the increasing complexity of quality improvements; (iv) M^{-1}, with $M=D$ if $0\leq j\leq J$ and $M=E$ if $J<j\leq 1$, is the adverse effect of market size

Under free entry R&D equilibrium, the expected reward for pursuing the $(k+1)^{th}$ successful research, must equal the after subsidy cost of research:

$$pb(j,k,t)\, V(k+1,j,t) = (1-s_r)\, rs(k,j,t) \tag{10}$$

s_r is an ad-valorem subsidy to R&D that decreases R&D costs, which can be specific to *E*- or *D*-R&D.

Re-arranging the terms, the instantaneous probability can be written by:

$$pb_M = \frac{\beta}{\xi} \frac{(1+\phi_{x,M})}{(1-s_{r,M})} \frac{(q-1)}{q} \left(\frac{p_M A_M (1-\alpha)}{(1+\phi_{x,M})} \right)^{1/\alpha} m - r(t) \tag{11}$$

Therefore, the TK growth rate equilibrium, Q_M, is given by the following TK path:

$$E(\Delta Q_M / Q_M) = \dot{Q}_M / Q_M = pb_M \left[q^{(1-\alpha)/\alpha} - 1 \right] \tag{12}$$

$[q^{((1-\alpha)/\alpha)}-1]$ is the R&D effect on TK and pb_M is the probability of successful R&D.

From (12), it is clear that R&D equilibrium rates reply negatively to the interest rate, *r*, and to a raise in $\tau_{x,D}$ and positively to an increase in $s_{r,M}$ and $s_{x,E}$. Thus, the direction of the TK is driven by the price channel and can be affected by government.

The government budget is assumed to be balanced at each time:

$$\tau_k r(t) \int_0^1 K(a,t)\, da + \tau_M w_M(t) \int_0^1 \left[u_w(a,t) M(a,t) \right] da + \tau_{x,D} X(t) = s_{x,E} X(t) + s_{r,M} RS(t) \tag{13}$$

The left-hand side of (13) is government tax revenue from assets income, $\tau_k r(t) K(t)$, from labour income, $\tau_M \left[w_E(t) E(t) + w_D(t) D(t) \right]$, and from an environmental tax on IGs that use *D*-technology, $\tau_{x,D} X(t)$. The right-hand side is government expenditures on environmental subsidies for *E*-IGs that use *E*-technology, $s_{x,E} X(t)$, and for R&D that enhance the environmental quality of both *E*- and *D*-specific IGs, $s_{r,M} RS(t)$.

Regarding the consumption, it is assumed a time invariant number of heterogeneous individuals, $a \in [0,1]$, that decide between consuming the aggregate FG and saving. For simplicity, $a \leq \bar{a}$ are unskilled-workers assumed to perform better using *D*-technology, while $a > \bar{a}$ are skilled-workers assumed to perform better using *E*-technology. The utility function for the individual is given by:

$$U(a,t) = \int_0^\infty \left[\frac{c(a,t)^{1-\theta} - 1}{1-\theta} \right] \exp(-\rho t)\, dt \tag{14}$$

where $c(a,t)$ is the consumption of Y by a, at t; $\rho > 0$ is the homogeneous subjective discount rate and $\theta > 0$ is the inverse of the intertemporal elasticity of substitution.
The solution for the individual's consumption path is the standard Euler equation:

$$\dot{c}(a,t)/c(a,t) = \dot{c}(t)/c(t) = \dot{C}(t)/C(t) = (1/\theta)\left[(1-\tau_k)\, r(t) - \rho\right] \tag{15}$$

where $\dot{c}(t)/c(t)$ yields the growth rate of consumption.

3 THE STEADY-STATE EQUILIBRIUM

In steady-state agents can maximize utility or profits and all markets clear. The dynamic equilibrium can be described by Q_E and Q_D paths. Therefore, the stable and unique steady-state endogenous growth rate, $g^*\left(\equiv g_D^* \equiv g_E^*\right)$, is:

$$g^* = \left(\frac{\dot{Y}}{Y}\right)^* = \left(\frac{\dot{X}}{X}\right)^* = \left(\frac{R\dot{S}}{RS}\right)^* = \left(\frac{\dot{Q}_D}{Q_D}\right)^* = \left(\frac{\dot{Q}_E}{Q_E}\right)^* = \left(\frac{\dot{C}}{C}\right)^* = \left(\frac{\dot{c}}{c}\right)^* = \frac{1}{\theta}\left[(1-\tau_K)r^* - \rho\right] \Rightarrow \left(\frac{\dot{p}_E}{p_E}\right)^* = \left(\frac{\dot{p}_D}{p_D}\right)^* = \left(\frac{\dot{\bar{n}}}{\bar{n}}\right)^* = 0 \tag{16}$$

By setting (15) equal to (12) we get the constant steady-state interest rate, $r^*\left(\equiv r_D^* \equiv r_E^*\right)$. By plugging r^* into (15) we get g^*. Equalizing the steady-state TK paths, $\left(\dot{Q}_D/Q_D\right)^* = \left(\dot{Q}_E/Q_E\right)^*$, it can also be found p_M* and $\bar{n}^*$.
By $s_{x,E}$ and $s_{r,M}$, government intervention affects positively r* and thus g*. Indeed, $s_{x,E}$ and $s_{r,M}$ stimulate R&D by increasing monopolistic profits and by reducing R&D costs, respectively. Conversely, $\tau_{x,D}$ and τ_K affect negatively r* and thus g*. In fact, $\tau_{x,D}$ and τ_K discourage R&D. The former because it reduces monopolistic profits and the latter due to the smaller expected marginal benefit. As τ_w is absent in equilibrium, it does not directly affect g^*.

4 TRANSITIONAL DYNAMICS AND SENSITIVITY ANALYSIS

From (12) and since r is unique, the stability of B is:

$$\frac{\dot{B}}{B} = \frac{\dot{Q}_E}{Q_E} - \frac{\dot{Q}_D}{Q_D} = \frac{\beta}{\xi}\left(\frac{q-1}{q}\right)(1-\alpha)^{1/\alpha}\exp(-\alpha)\left\{ e\left(1+\frac{A_E}{A_E+A_D}\right)^{\sigma}\left(\frac{1-s_{x,E}}{1-s_{r,E}}\right)\left(\frac{A_E}{1-s_{x.E}}\right)^{1/\alpha}\left[1+\left(\frac{Q_E}{Q_D}\frac{e\ E}{d\ D}\right)^{-1/2}\right]^{\alpha} - d\left(\frac{1+\tau_{x,D}}{1-s_{r,D}}\right)\left(\frac{A_D}{1+\tau_{x.D}}\right)^{1/\alpha}\left[1+\left(\frac{Q_E}{Q_D}\frac{e\ E}{d\ D}\right)^{1/2}\right]^{\alpha}\right\} \tag{17}$$

We solve the model numerically to illustrate the effect of government intervention on both TK bias, B, and FG bias, $\bar{n}$, using the parameter values in Table 1.

Table 1. Baseline parameter values

Parameter	Value	Parameter	Value
A_E	1.50	α	0.70
A_D	1.00	β	1.60
E	1.20	θ	1.50
D	1.00	ρ	0.02
E	0.70	σ	2.00
D	1.00	ξ	4.00
Q	3.33	$s_{x,E}$, $s_{r,E}$, $s_{r,D}$ $\tau_{x,D}$	0.00

Source: Authors' assumptions based on theoretical framework and on the literature.

The parameter calibration is based on empirical literature and on theoretical specifications. The mark-up ratio, $q=(1/(1-\alpha))$, is set in line with the mark-up estimates of Kwan et al. (2003). θ is in accordance with previous calibrations of growth models, assumed to exceed one (e.g., Jones et al., 1993) and ρ follows from previous works on growth (e.g., Dinopoulos, 1999). The remaining parameters have been calibrated taking into account our theoretical assumptions and considering a steady-state growth rate of 2%, the average *per capita* growth rate of the USA in the post-war period.
Considering the baseline values in Table 1, the paths of B and $\bar{n}$ with and without government intervention are displayed in Fig.1 and Fig. 2, respectively.

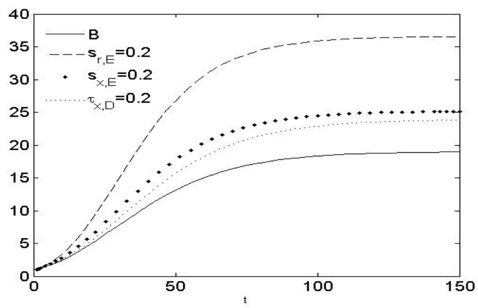

Fig. 1 Transitional dynamics of TK bias (B) under government intervention

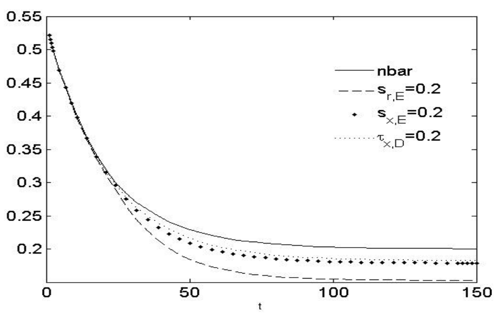

Fig. 2 Transitional dynamics of FGs bias ($\bar{n}$) under government intervention

Fig. 1 and Fig. 2 compare the baseline steady-state values of, respectively, B and $\bar{n}$, under no government intervention to the ones with government intervention.
With a raise of each type of subsidies and tax, it is clear that $s_{r,E}$ is the most contributor to heighten both the TK bias and the final good sector bias while $\tau_{x,D}$ is the least contributor. Indeed, $s_{r,E}$ reduces E-R&D costs, stimulating E-R&D and increasing the E-TK growth rate. Conversely, $\tau_{x,D}$ decreases the profits of D-IG producers discouraging D-R&D in favour of E-R&D. Thus, the production of E-IG rises, increasing the number of E-FGs, whose relative prices decrease continuously towards the new steady-state. Therefore, $\bar{n}$ decreases, showing an improvement of the environmental quality, see (2). Hence, as a result of the price channel, B is increasing, but at a falling rate until it reaches its new higher steady-state and $\bar{n}$ is decreasing, but at a falling rate until it reaches its new lower steady-state
Table 2 presents the steady-state values of both the TK bias, B, and the environmental quality bias, $\bar{n}$ under no government intervention. Table 3 depicts the steady-state values of both the TK bias and the environmental quality bias under government intervention.

Table 2. Steady-State Values of B and $\bar{n}$ under No Government Intervention

Variables	Initial Values	Steady-state values under no government intervention
B	1	18.96
$\bar{n}$	0.52	0.20

Table 3. Steady-State Values of B and $\bar{n}$ under Government Intervention

Variables	Steady-state values under government intervention		
	$s_{r,E}=0.2$	$s_{x,E}=0.2$	$\tau_{x,D}=0.2$
B	36.53	25.13	23.82
$\bar{n}$	0.15	0.178	0.18

5 CONCLUSION

This paper presents a dynamic general equilibrium growth model with endogenous skill-biased technological change. It analyses the contributions of environmental policies to the ecological goods production, when consumers are indifferent between ecological and dirty goods. A measure of the environmental quality is also provided, expressed by the FGs sector bias, $\bar{n}$.

We found that technological progress leads to relatively more production of ecological goods and environmental quality improvements when green firms and green research are supported by policy and/or dirty activities are taxed. This result is in line with, for instance, Ricci (2007). Notwithstanding, the raise in the number of ecological FG reduces their relative prices, discouraging ecological TK and ecological production. Consequently, through the price channel, ecological TK bias and ecological FG sector bias increases at a falling rate until they reach their new steady-state.

For future research, it would be interesting to develop an endogenous multi-country growth model with different environmental endowments to discuss issues of global policy coordination and to verify whether, with international trade, environmental regulation would be sufficient to encourage both the development of clean technologies and the production of ecological goods.

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The impact of Public Policies in the renewables deployment: A comparative study between installed capacity and electricity generation

António Cardoso Marques[1], José Alberto Fuinhas[2], Diogo André Pereira[3]

[1] *NECE, University of Beira Interior, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, amarques@ubi.pt*
[2] *NECE, University of Beira Interior, Management and Economics Department, Estrada do Sineiro, 6200-2009 Covilhã, Portugal, fuinhas@ubi.pt*
[3] *University of Beira Interior, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, pereira.diogo.as@gmail.com*

ABSTRACT

The design of public policies supporting renewables is crucial to face the 21st century economic growth and sustainable development. One of the core issues on economic growth is the renewable energy. Therefore, this research focuses on the 20 countries with the highest electricity production under renewables using a database of policy-related variables composed from the date of the first implemented policy. This paper examines the short- and long-run effects of public policies supporting renewables and other drivers to promote renewable energy sources deployment, in a comparative analysis. On the one hand, it examines these effects on electricity generation and installed capacity by the comparison of the results. On the other hand, it assesses these effects on renewables both in an aggregated format and disaggregated by the new renewable sources. A compressive analysis of the public policies supporting renewables with both short- and long-run effects was considered and it is pursued and discussed. The Driscoll-Kraay estimator with fixed effects proved to be adequate to handle with the characteristics of the panel data. Results emphasize that renewable energy sources implementation has been established essentially upon policy-drivers, but the few market-drivers have been capable to promote RES implementation.

KEYWORDS: Public Policies Supporting Renewables, Renewable Energy, panel dynamic effects, Driscoll-Kraay estimator

1 INTRODUCTION

The Public Policies Supporting Renewables (PPSR) are mainly to deal with energy market failures. Indeed, the fossil fuels technologies do not internalize in their price the costs of pollution. The shift from fossil fuels towards Renewable Energy Sources (RES) in the domestic electricity mix is a major solution to preserve the environment and to cut off the external dependence of electricity sources. As well known the RES imply a large amount of investment in an initial phase, due to the lack of technological advance and the insufficiency of know-how. Notwithstanding their need of public intervention, they are already making their own path in order to make themselves competitive. Despite some recent empirical studies (e.g. Aguirre & Ibikunle, 2014; Marques & Fuinhas, 2012; Polzin et al, 2015), the literature focused on the relationship between PPSR and RES deployment is mainly qualitative and normative (e.g. Abdmouleh, Alammari, & Gastli, 2015; Gan, Eskeland, & Kolshus, 2007; Harmelink, Voogt, & Cremer, 2006), revealing a positive impact of PPSR on RES implementation. On the other hand, empirical literature (e.g. Aguirre & Ibikunle, 2014; Marques & Fuinhas, 2012; Polzin et al., 2015) demonstrates dissimilar effects of PPSR subcategories on the RES deployment. Moreover, the empirical literature remains scarce, and some conclusions are not consensual. Therefore, the assessment of the apportionment of short- and long-run effects, thus providing a deeper understanding of the dynamic relationship.

The valuation of the consequences of the PPSR is shown to be crucial, given that governments are facing simultaneous objectives. On the one hand, they must keep the deployment of RES within the domestic electricity mix. On the other hand, however, they have to look for some incentives that require fewer resources coming from the whole economy. In fact, these incentives may even compromise the economic growth as quoted by some authors (Al-mulali, Fereidouni, & Lee, 2014; Cowan, Chang, Inglesi-Lotz, & Gupta, 2014; Lin & Moubarak, 2014; Marques & Fuinhas, 2015). In short, the balance of these two dimensions is essential to design appropriate energy policies, which is the main motivation for this research. Therefore, this paper aims at providing support as well as discussing the appropriate design of PPSR for the renewables deployment.

This research uses a panel data based on the 20 countries with the highest electricity generation production through RES and a time span from 1990 until 2014. The policy-related variables database has been made from the date of the first implemented policy but it only uses the time span from 1990 until 2014.

A dynamic approach was used to analyze the effects of PPSR, in categories and subcategories, on the installed capacity and on the electricity production under RES in an aggregated format and disaggregated by the new sources of renewable energies, namely the wind power and the solar photovoltaic. On the one hand, the effects of PPSR on electricity production and on the installed capacity will be evaluated in comparison, in order to analyze if PPSR have dissimilar effects. On the other hand, the effects of the PPSR on the aggregate renewables, on the wind power and on the solar photovoltaic will be assessed in comparison, in order to analyze the technology specific effects of the PPSR.

Both panel data estimators and co-integration/long memory will be pursued and discussed, namely dealing with the heterogeneity of the panel and the country specific effects. The comprehensive analysis of the impacts of PPSR on RES implementation requires an improvement of econometric techniques which take into consideration both short- and long-run effects, for which the Driscoll-Kraay estimator with fixed effects proves to be appropriate. The results prove that PPSR stimulate the renewables accommodation. However, the technology specific policies have dissimilar effects on the wind power and on the photovoltaic deployment. As well, the other control variables have a divergent effect on RES deployment. Consequently, the disaggregation of RES and the comparative study between electricity production and installed capacity are extensive but efficient.

2 POLICIES TO PROMOTE RENEWABLE ENERGY SOURCES IMPLEMENTATION

This study uses the PPSR categorization of Global Energy Policies and Measures Data Base of International Energy Agency (IEA). Both their categories and subcategories are displayed and explained in Table 1. According to the IEA criteria, the categories of PPSR are: Direct Investments (DI); Fiscal/Financial Incentives (FFI); Market-based Instruments (MBI); Information and Education (INFE); Policy Support (PS); Research, development and deployment (RDD); Voluntary Approaches (VA); and Regulatory Instruments (RI).

Table 1. PPSR categorization of Global Energy Policies and Measures

Category	Subcategory	Details
Direct Investment (*DI*)		Non-market based instrument related to governments intervention to create the necessary conditions and framework to encourage the initial investments.
	Procurement Rules (*DI_PR*)	The preference of public entities for purchasing renewable energy and services.
	Infrastructure Investment (*DI_II*)	The creation of necessary conditions to implement RES, such as grid access.
	Funds to Sub-national Governments (*DI_FSG*)	The preference to support RES projects in disadvantaged regions or with endogenous resources to explore RES.
Fiscal/Financial Incentives (*FFI*)		Non-market based instrument to reduce the burden of initial investments on RES implementation, and to stimulate RES research and development.
	Feed-in Tariffs/Premiums (*FFI_FTP*)	It guarantees the access and dispatch to RES supplies, offering a fixed and guaranteed price for the generated electricity.
	Grants and Subsidies (*FFI_GS*)	The monetary help that does not need to be repaid, it is granted for a specific purpose of an eligible RES project.
	Loans (*FFI_L*)	The governments ensure financing RES projects and companies, with a long-term commitment, in financial institutions, regionals or nationals.
	Taxes (*FFI_T*)	Tax credit based on the amount of investment in a RE facility or the amount of energy that it generates in the relevant year.
	Tax Relief (*FFI_TR*)	Tax exception or reduction to projects and companies investing in renewables-related goods and services.
Market-Based Instruments (*MBI*)		State tools to ensure that electricity generation through RES, which can be traded between players
Information and Education (*INFE*)		The promotion of knowledge, awareness and training among relevant stakeholders or general public to energy usage or emissions performance.
Policy Support (*PS*)		It refers to steps in the ongoing process to developing, supporting and implementing policies. This includes strategic plans that guide policy development and the creation of specific bodies to support a policy.
Research, development and deployment (*RDD*)		Policies and measures aimed at supporting technological advancement, through direct investment, or facilitation of investment, in technology research, development, demonstration and deployment activities.
Voluntary Approaches (*VA*)		It tracks the measures that are undertaken voluntarily either by public agents or by a private sector, unilaterally or bilaterally.
Regulatory Instruments (*RI*)	Codes and Standards (*RI_CS*) Obligation Schemes (*RI_OS*) Other Mandatory Requirements (*RI_OMR*)	It covers a wide range of instruments a government uses to impose targets, obligations and standards on actors, requiring them to undertake specific measures and report on specific information.

The energy generated from RES is noncompetitive with energy produced from conventional sources because the generation costs are lower for fossil and nuclear plants. Indeed, this is due to the fact that most of the conventional power plants were built with significant subsidies and their capital costs have now been covered. Also, RES plants have a higher proportion for capital costs from the total plant cost. As well, the non-consideration of external additional costs of energy produced from fossil fuels (Abdmouleh et al., 2015). Therefore, the RES need policy instruments to stimulate activities, behaviors or investments using financial supports and price signals to influence the market.

3 DATA AND METHODOLOGY

This study uses a panel data with annual frequency data, from 1990 until 2014, due to the new renewable sources that appeared in 1990. In accordance with the study object of this research, the countries selected were Australia, Belgium, Canada, China, Denmark, Finland, France, Germany, India, Italy, Japan, Mexico, Netherlands, Poland, Portugal, Spain, Sweden, United Kingdom and United States. Brazil was excluded once there was not any available data concerning half of the study period. One intends to assess the effects of PPSR when examining the RES either in an aggregated format or disaggregated by the new sources of generation, based on the following models and dependent variables:

- Model I – electricity generation through RES excluding hydro (DLGEG_REN);
- Model II – electricity generation through wind power (DLGEG_WIND);
- Model III – electricity generation through solar PV (DLGEG_SOLAR);
- Model IV – installed capacity of RES excluding hydro (DLCAP_REN);
- Model V – installed capacity of wind power (DLCAP_WIND);
- Model VI – installed capacity of solar PV (DLCAP_SOLAR).

Following the literature, the paper controls the other drivers of RES and the policy-related variables, table A.1 gives the definition of variables, sources and descriptive statistics. Therefore, the prefix "L" and "D" denotes the natural logarithms and the first differences of logarithms, respectively.

The literature advises to pay attention both to the nature of variables and to the idiosyncrasies of countries under analysis when one resorts to an empirical approach with a macro panel, well known that the cross section dependence is a common occurrence. In fact, the panel incorporates various EU countries. Consequently, the countries have similarities in the policies conception and in the tendency to implement RES. The Pesaran (2004) cross section dependence, CD-test (Table 2) were performed and strongly support the presence of cross section dependence in all variables except for the *DLREN*. It has not been possible to perform the CD-test in the policy-related variables, even their being in their natural logarithms.

The unit roots test of first generation was performed, namely LLC (Levin, Lin, & Chu, 2002), ADF-Fisher (Maddala & Wu, 1999) and ADF-Choi (Choi, 2001). Therefore, the second generation unit root test CIPS (Pesaran, 2007) was also performed because this test has the advantage of being robust in the presence of cross section dependence. In order to preserve space, the unit root test is not shown although the test proves that all variables are I(1) in their levels, except for the LGEG_WIND that could be a borderline I(0)/I(1).

Table 2. Cross section dependence test

Variables	CD-test	Corr	Abs(corr)
LGEG_REN	46.26***	0.936	0.936
LGEG_WIND	46.65***	0.945	0.945
LGEG_SOLAR	45.68***	0.924	0.924
LCAP_REN	46.8***	0.948	0.948
LCAP_WIND	46.66***	0.945	0.945
LCAP_SOLAR	45.88***	0.928	0.928
LOIL	57.74***	0.898	0.898
LCOAL	27.63***	0.43	0.759
LGAS	3.02***	0.044	0.498
LCO2	15.19***	0.236	0.557
LGDP	58.67***	0.909	0.909

Notes: Cd-test has N(0,1) distribution, under the H0: cross section independence. ***, denotes significance at 1% level.

Regarding the main objective of this paper, the dynamic analysis of PPSR effects on the RES implementation, an autoregressive distributed lag (ARDL) model has been used. In fact, this model has the advantage of treating the functional relationships among variables. Consequently, it makes possible to breakdown the total effect into short- and long-run components. As well, this model has the important property of being robust in the presence of variables that are I(0), I(1), or borderline. This feature allows us to handle variables with long memory patterns appropriately. Indeed, the literature shows that the ARDL model has consistent and efficient parameters estimates, inferring parameters based on standards tests. Furthermore, the models specification includes variables that are in natural logarithm, and first logarithms differences, their coefficients being elasticities and semi-elasticities, respectively. Firstly, the collinearity and multicollinearity were checked. Both correlation of coefficients and the variance inflation factor (VIF) were computed to all models. The low correlation values and VIF statistics strongly support that multicollinearity is far from being a concern on all models (not shown). After that, a battery of model specification tests were performed. Table 3 presents the tests: (i) the Breusch and Pagan LM test for random effects (Breusch, T. S. Pagan, 1980) to test the existence of panel effects; (ii) the Hausman test, fixed effects (FE) vs. random effects (RE), test the presence of individual effects against random effects; (iii) the modified Wald statistics for groupwise heteroskedasticity (Greene, 2003); (iv) the Woldridge test for serial correlation (Drukker, 2003); (V) the test of cross section dependence of (Pesaran, 2004), (Frees, 1995) and (Friedman, 1937); and (VI) the tests to assess the panels heterogeneity of crosses, the Hausman RE vs. FE, the Mean Group (MG) vs. Pooled Mean Group (PMG), and the MG vs. Dynamic Fixed Effects (DFE).

The specification tests reveal that there is heteroskedasticity in all the models, panel autocorrelation and contemporaneous correlation, except for models I and V where the existence of contemporaneous correlation is not proved by any of the tests performed. All models reject the null hypothesis of Hausman test FE vs. RE. There is evidence of the correlation between countries individual effects and explanatory variables. Besides, FE is especially adequate to analyze the influence of variables that vary over time. Furthermore, this being a macro panel with policy-related variables, the good econometrics practices advise to assess the panel heterogeneity of crosses. Both the MG and PMG estimators were applied. Indeed, the literature considers the MG one to be the most flexible once it estimates if the long-run average coefficients are consistent but it is inefficient when there is a slope of homogeneity (Shin, Pesaran, & Smith, 1999).

Table 3. Specification tests

Models	I	II	III	IV	V	VI
BP LM test for RE	37.22***	11.42***	3.70**	2.72**	5.66***	2.71**
Modified Wald test	2318.09***	818.22***	1834.20***	3324.98***	860.66***	783.03***
Wooldridge test	21.244***	24.027***	46.247***	3.584*	3.357*	36.495***
Pesaran's test	-0.627	4.500***	2.453**	0.57	-0.106	-0.787
Frees' test	0.089	1.748***	0.391***	0.301***	-	0.958***
Friedman's test	13.668	25.065	33.936**	20.017	3.263	7.289
Hausman tests:						
RE vs. FE	91.34***	120.39***	42.76***	23.30**	32.24***	56.65***
MG vs. PMG	39.48***	54.55***	41.02***	30.22***	220.01***	1837.34***
MG vs. DFE	23.08	0.3	8.79	0.34	0.66	0.02

Notes: ***, **, * denote significance at 1%, 5% and 10% level, respectively; the BP LM test for RE results for H0: the variances across entities are zero; the modified Wald test has χ^2 distribution and test H0: $\sigma_c^2 = \sigma^2$, for c=1,…,N; the Wooldridge test is normally distributed N(0,1) and tests H0: no serial correlation; Pesaran's, Frees' and Friedman's test the H0: residuals are not correlated; Hausman results for H0: difference in coefficient is not systematic including the constant.

The results lead to the rejection of the most flexible models, MG and PMG, proving that FE is the most suitable estimator for all the models. Accordingly, the prevalence of a homogenous panel indicates that countries share common coefficients and are suitable to be treated as a group as these results could be interpreted as evidence that globalization and international commitments such as the Kyoto Protocol and EU Directives shape identical measures for the countries. Such as noted by specification tests, the Driscoll & Kraay estimator of 1998 proves to be appropriate to handle with those data features. Indeed, it is a nonparametric covariance matrix estimator that produces a robust standard error to several phenomena, namely temporal dependence. Both the FE estimator and the FE estimator with robust standard errors and with AR(1) disturbance were estimated as a benchmark.

4 RESULTS AND DISCUSSION

Table 4 discloses the semi-elasticities (short-run) and elasticities (long-run) for each model. The elasticities are computed from the estimated models (not shown) by dividing the coefficient of the variables by the coefficient of ECM, both lagged once, and then multiplying the ratio by -1. On the whole, all models support co-integration/long memory, given that the ECM are negative and highly statistically significant. Indeed, this emphasizes the relevance of using econometric techniques that are able to breakdown the total effect into short- and long-run components. In short, the first observation evidenced that PPSR subcategories have dissimilar effects on RES deployment. Furthermore, some PPSR subcategories elasticities are above one, revealing they were used efficiently, in contrast with the PPSR subcategories elasticities that are below one.

The Direct Investments subcategories show dissimilar results; the infrastructure investments, DI_II, are more related to wind power, have a positive and statistically significant effect on the semi-elasticities and on the elasticities. Indeed, the wind power requires access to the grid, which implies a large amount of investment. The DI_FSG, money intermediated by regional, local or municipal levels of RES implementation, has not produced the desirable effect on renewables, showing a negative and significant elasticities, this subsidies being either not properly applied or ignored by the investors due to the scale of the projects. The procurement rules, DI_PR related to the purchases of RES energy and services by public entities, have a positive and statistical significance for the RES deployment.

On the one hand, grants, subsidies and loans, FFI_GS and FFI_l, demonstrated to be inefficient to implement RES despite the results that prove a positive effect of loans on generation through RES in the aggregated format. On the other hand, the feed-in tariffs and tax relief, FFI_FTP and

TR, show positive and highly significant elasticities although tax relief being a more specific policy to implement wind power and feed-in tariffs more specific to implement solar PV. Indeed, this proves that the new sources of renewables are largely dependent on public financing.

Table 4. Elasticities and adjustment speed

Dependent variables Models	DLGEG_REN I	DLCAP_REN II	DLGEG_WIND III	DLCAP_WIND IV	DLGEG_SOLAR V	DLCAP_SOLAR VI
Short-run elasticities						
DLOIL				-1.4735***		
DLCOAL					-0.2852*	-0.5151***
DLGAS	0.3132***			-0.1486**	0.5221***	0.5903***
DLCO2	-0.3191**	-1.2623**		0.5134**		
DLGDP	0.8331**					
DLDI_FSG	-0.2124***					
DLDI_II				0.2736***		-0.3617*
DLDI_PR	0.2254***		0.3214***		-0.5066***	
DLFFI_GS			-0.1103**			
DLFFI_L					-0.3218**	
DLMBI	0.1234**		0.1986*			
DLRI_CS			0.1550**		0.3132***	0.4055*
DLRI_OS		-0.2330**			-0.3162***	
DLRDD					0.4153**	0.3089***
Speed of adjustment						
ECM	-0.1750***	-0.5113***	-0.1274***	-0.0813***	-0.1548***	-0.1588***
Computed long-run elasticities						
LOIL		-3.4345***	6.7973***		-4.5536***	
LCOAL	-.5095***	-.97616*	1.8266***	1.8538***	-1.6904*	-2.7177***
LGAS	1.5246***	.78519***			2.9384***	2.7667**
LCO2		-.43139***				
LGDP		2.2799***		3.1657**		
LDI_FSG	-1.0648***	-1.7397***				
LDI_II	-.7841***		2.1759***			
LDI_PR	1.4548***	.34713*				2.0080**
LFFI_FTP	.1990***				1.5763***	1.1723***
LFFI_GS						-1.2062***
LFFI_L	.94343***		-1.5269***			
LFFI_TR	.53893**	1.1038***	1.7609***	2.9972***		
LMBI	.21385**	.2721**				.83194**
LIE	.59661***	1.3405***		1.2882**		
LPS					1.0969**	1.0390***
LRI_CS		-.50879***	.69975***		1.4894**	
LRI_OS					-3.1233**	
LRI_OMR			-1.1426*	-1.3618**		
LRDD				-1.2579**	-3.1233***	1.5820***
LVA	-.4788***					

Notes: ***, **, * denote significance at 1%, 5% and 1% level, respectively. ECM denotes the coefficient of variables LGEG_REN, LCAP_REN, LGEG_WIND, LCAP_WIND, LGEG_SOLAR and LCAP_SOLAR, model I, II, III, IV, V, VI, respectively, and lagged once.

Accordingly, with literature, the results prove there are negative FFI subcategories, being FFI_FTP and FFI_TR the most efficient instruments to promote solar PV and wind power, respectively. Indeed, feed-in tariffs are in line with the investors preferences, guaranteeing a fixed price for the generated electricity. In fact, focusing, for instance, on the RI_CS, the subcategory of PPSR that incorporates the Renewable Standard Portfolio, there is an obvious increase of the share of electricity production under renewables sources. This policy instrument shows positive and statistically significant elasticities in the models III and VI, meaning these policy instruments affect the solar PV and wind power deployment positively. Indeed, the difference between FFI_FTP and RI_CS comes from the fact that the feed-in tariffs policy is more employed in the EU countries while RI_CS one has the preference of the American countries. Actually, RI_CS does not guarantee a fixed price but it imposes minimum limits of electricity generation from RES, in contrast with FFI_FTP and FFI_TR which are attached to the public budget (Bird et al., 2005; Carley, 2009; Menz & Vachon, 2006).

Focusing, for instance, on the market based or market-driven instruments, one can observe a booster of RES implementation. Indeed, the MBI show positive and statistically significant elasticities both in the semi-elasticities and in the elasticities, but their elasticities are below one. This market-driven instruments intended to make market electricity more competitive, once the price of RES generation depends on the demand and supply of green and white certificates (Menanteau, Finon, & Lamy, 2003; Ringel, 2006).

The policies to promote general public and stakeholders´ knowledge and awareness prove to be effective on implementing RES capacity and promoting their electricity generation, principally in what concerns the wind power installed capacity while the strategic plans, the ones that guide policy development and the creation of specific bodies to support policies, i.e., the policy support, are more effective on solar PV implementation.

Research, development and deployment policies have demonstrated a positive and statistically significant effect on solar PV installed capacity implementation, in the semi-elasticities and in the elasticities. Otherwise, they have shown a negative effect on the long-run wind power installed capacity. Meanwhile, they present a dissimilar effect on electricity generation under solar PV in the semi-elasticities and in the elasticities. Indeed, the solar PV technologies had a great technological development, mainly before 2004 when they increased their efficiency in 16%, while technologies exploring the wind power have been showing a slow development (International Renewable Energy Agency, 2012).

The RES deployment, principally the one of the new sources of renewables, depends mostly on policy-driven instruments. Consequently, the RES deployment requires incentives and resources coming from the whole economy and directly linked with public budgets. In short, the results evidence that policymakers will have to create more policies to stimulate behaviors and investments through price signals in order to influence the market through market-driven practices. Indeed, some authors (Liao, Ou, Lo, Chiueh, & Yu, 2011) argue that the solution to externalities internalization in the energy market lies in the removal of market barriers, in its liberalization. They defend the removal of all the incentives and subsidies derived from the public budget, either for fossil fuels or RES and the inclusion of taxes on fossil fuels products to pay for the effects of greenhouse gases emissions. In short, policymakers can view this perspective and add more market-driven policies as a remedy to make RES more competitive without compromising the economic growth.

Although the results demonstrate that carbon dioxide emissions unexpectedly have a negative impact on RES deployment, one could find a positive effect on wind power installed capacity in the short-run. The majority of results prove that fossil fuels do not increase RES deployment. However, intensity of oil and intensity of coal in the economy has a positive impact on electricity generation under wind power, and gas intensity has positive and statistically significant elasticities, either in semi-elasticities or elasticities both on RES and solar PV deployment. Lastly, gross domestic product has been efficient in the wind power installed capacity implementation as well as in the implementation of RES, considering all renewable sources in an aggregated format. The results of drivers to promote RES are in line with literature (Aguirre & Ibikunle, 2014; António C. Marques, Fuinhas, & Pires Manso, 2010; António Cardoso Marques & Fuinhas, 2012; Polzin et al., 2015).

5 CONCLUSION

This research is focused on the 20 countries with the highest electricity production under renewable sources, for the time span of 1990 until 2014, including a database of the policy-related variables constructed from the date of the first policy implemented. It adds a new empirical evaluation considering both semi-elasticities and elasticities to assess the PPSR efficiency in RES deployment. Moreover, it provides us with a comparative analysis. On the one hand, it is possible to compare the PPSR efficiency between RES installed capacity and electricity generation under RES. On the other hand, it makes a comparison of the PPSR efficiency between the RES in an aggregated format and the new sources of renewables, such as wind power and solar PV.

The results proved that PPSR have dissimilar effects on installed capacity and on electricity generation. Indeed, most policies are more efficient to promote installed capacity of RES although there are policies more focused on increasing the electricity production under RES. It is proved that policies are more specific in relation to technologies, whereas policies that affect solar PV technologies do not affect wind power exploitation. On the contrary, it is proved that subcategories of PPSR are not efficient in promoting RES deployment. In fact, these effects show that either policies have not produced the desirable effects yet or their framework and constitution are inadequate.

In conclusion, the RES deployment, principally the deployment of the new sources of renewables has been established essentially upon policy-driven attitudes instead of market-driven instruments. Indeed, only one market-driven policy proves to be inefficient to RES implementation although there are positive signals. The policymakers have to change their attitude and avoid compromising the economic growth, once most RES used, such as wind power and solar PV, have been dependent on policies directly related to public budgets, and not on the market signals. Indeed, in our point of view, there are two solutions for the RES to follow their own path and make themselves competitive: the market liberalization with policy instruments only related to the regulation of market-drivers and a mix of policy-driven instruments and market-drivers instruments, where the policy instruments only stimulate the behaviors and investments using less financial support.

Overall, the results seem robust and suggest that policies framework and implementation must be changed so that the economic growth can not be compromised and the RES can become competitive by their own strengths without any externalities.

6 APPENDIX

Table A.1. Data: definition, sources and descriptive statistics

Variable	Definition	Source	Obs	Mean	S.D.	Min	Max
LGEG_REN	Gross electricity generation from renewable sources including wind, geothermal, solar biomass and waste (kgoe)	BP Statistical Review of World Energy 2015	475	21.10936	1.549768	13.72585	24.89793
LCAP_REN	Installed capacity of renewable sources including wind, solar and geothermal (MW)	*idem*	356	6.968731	2.467547	-1.609438	11.86945
LGEG_WIND	Gross electricity generation from wind power (kgoe)	*idem*	467	18.85092	2.867758	11.02581	24.45017
LCAP_WIND	Logarithm of installed capacity of wind power (MW)	*idem*	342	6.848448	2.351075	0.6931472	11.64928
LGEG_SOLAR	Gross electricity generation from solar PV (kgoe)	*idem*	403	15.88722	2.824093	7.724336	22.79061
LCAP_SOLAR	Installed capacity of solar PV (MW)	*idem*	321	4.078564	2.812935	-1.609438	10.55059
LOIL	Oil intensity on economy (kg/2005 U.S. dollars GDP)	BP Statistical Review of World Energy/World Data Bank	475	-2.709295	0.4243617	-3.64057	-1.542425
LCOAL	Coal intensity on economy (kgoe/2005 U.S. dollars GDP)	*idem*	475	-3.545482	1.241482	-5.567009	-0.0057675
LGAS	Natural gas intensity on economy (kgoe/2005 U.S. dollars GDP)	*idem*	468	-3.679467	0.799652	-7.527457	-2.397641
LCO2	Carbon dioxide emissions (Mt)	BP Statistical Review of World Energy	475	26.77218	1.431722	24.42697	29.90942
LGDP	Gross domestic product (2005 U.S. dollars per capita)	World Data Bank	475	9.867202	1.171716	5.98734	10.83358
LDI_FSG	ANPM – funds to sub-national governments	IEA policies and measures database	475	0.0829502	0.285623	0	1.94591
LDI_II	ANPM – infrastructure investments	*Idem*	475	0.0909984	0.2644739	0	1.098612
LDI_PR	ANPM – procurement rules	*Idem*	475	0.0839216	0.2384819	0	1.098612
LFFI_FTP	ANPM – feed-in tariffs/premiums	*Idem*	475	0.386236	0.6513364	0	2.302585
LFFI_GS	ANPM –grants and subsidies	*Idem*	475	0.6375805	0.7184789	0	2.639057
LFFI_L	ANPM - loans	*Idem*	475	0.1751727	0.3971497	0	1.791759
LFFI_TR	ANPM – tax relief	*Idem*	475	0.4063223	0.5839833	0	2.397895
LMBI	ANPM – market based instruments	*Idem*	475	0.1791381	0.417487	0	1.791759
LIE	ANPM – information and education	*Idem*	475	0.2122854	0.5076168	0	2.772589
LPS	ANPM – policy support	*Idem*	475	0.4822872	0.6613716	0	2.833213
LRI_CS	ANPM – codes and standards	*Idem*	475	0.2397924	0.4432486	0	2.197225
LRI_OS	ANPM – obligation schemes	*Idem*	475	0.2307238	0.4011441	0	1.94591
LRI_OMR	ANPM – other mandatory requirements	*Idem*	475	0.3310364	0.4975556	0	2.197225
LRDD	ANPM –research, development and deployment	*Idem*	475	0.4050879	0.6280229	0	2.70805
LVA	ANPM – voluntary approaches	*Idem*	475	0.1456572	0.3553106	0	2.079442

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The economic and environmental assessment of electricity storage investments. Any need for policy incentives?

Amanda Spisto[1*], Nikola Hrelja[1], Gianluca Fulli[1]

[1]*European Commission, Joint Research Centre, Institute for Energy and Transport, Westerduinweg 3, NL-1755 LE Petten, The Netherlands*

ABSTRACT

This study contributes to the current discussion on the economic viability of new investments in electricity storage technologies, the associated environmental impact, measured in terms of changes in CO2 emissions and level of renewables in the system, and some policy related questions. The analysis is based upon a price-taker model under perfect price forecasts simulating the dispatch of a marginal pumped-hydro storage plant. The optimization problem is solved with CPLEX 12.1 under GAMS and it is applied to the case study of two zones of the Italian power market, Sicily (SICI) and Rossano (ROSN). This case study is of particular interest because the zone SICI features the highest and most volatile price levels in the country. Additionally, the potential of wind and solar generation makes these regions a possible future leading producers of renewables in Italy.

A storage plant is located in each zone and maximizes arbitrage profits from zonal price spread between off and on peak hours. The higher is the volatility of prices, the higher are private profits for the storage investor.

In the first part of the study we compare the private investment opportunities of the two storage projects with the NPV approach. In the second part we assess the impact of storage operation on the level of CO2 emissions and renewable generation in the system. The net environmental impact is determined by the difference between the kg of CO2 of the power integrated during charging hours and the kg of CO2 displaced during discharging hours. In the same way we calculate the net renewable generation integrated by the storage.

Results of the environmental impact assessment show an overall increase in CO2 emissions, with remarkable differences between zones and higher levels of renewable generation aftwer storage is added to the system. The NPV results improve when both private and social values are considered, though they remain negative without changing the business case of both storage investment projects. We show that the operation of a PHS, despite being costs minimizing, does not guarantee optimality in terms of environmental impact. The investment analysis shows no reasons for public incentive to private storage investments in the two Italian zones. Policy support to the storage technologies should be granted if the social value of the investment would at least cover the negative results of the private profits assessment.

KEYWORDS: Flexibility, renewable generation, price-taker model, NPV, real option analysis.

*corresponding author: Amanda.Spisto@ec.europa.eu

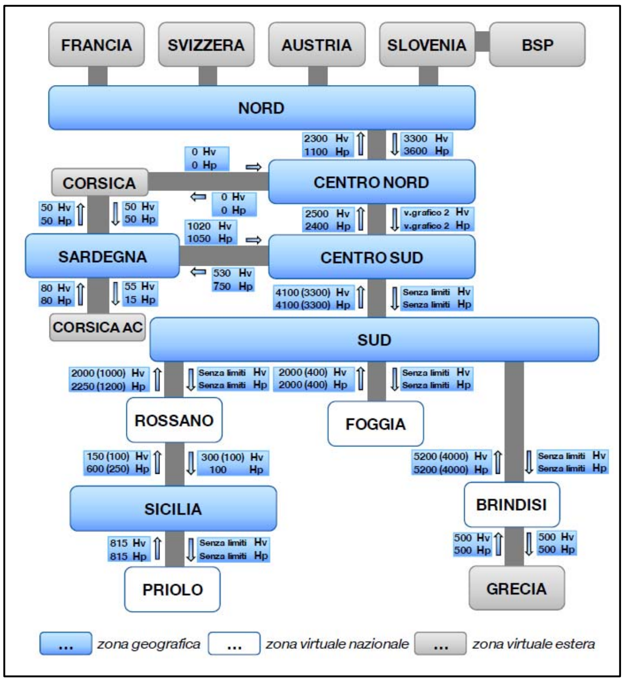
1 INTRODUCITON

Under the ambitious targets for a green power system set by the European Commission by 2050, the need of new investment in flexible and efficient technologies to integrate high shares of renewable generation is on the top of the agenda of all national European governments. This study contributes to the current discussion on the economic viability of new investments in electricity storage technologies (Gianfreda et al 2013), the associated environmental impact in terms of changes in CO2 emissions and integration of renewable generation (George et al. 2011) (McKenna et al. 2013) and some policy questions related to the effect of public support measures to energy storage projects (Grünewald et al. 2011) and (Sioshansi 2010).

Our analysis is applied to the case study of two zones in the Italian power market (IPEX). The electricity market in Italy is divided into price zones, characterized by maximum transmission capacity between a pair of zones and according to infrastructure constraints set by the Italian TSO (Terna SpA).

Majority of the zones are interconnected with two other zones, with the exceptions of CNORD, CSUD and SUD that are interconnected with 3 other zones and the virtual zones (that connect the country with foreing zones) and 2 poles of limited production (BRNN, PRGP, ROSN) that share border with only one zone (Fig. 1).

Figure. 1. Zones and interconnecitons in the Italian power market



Source: Terna SpA online

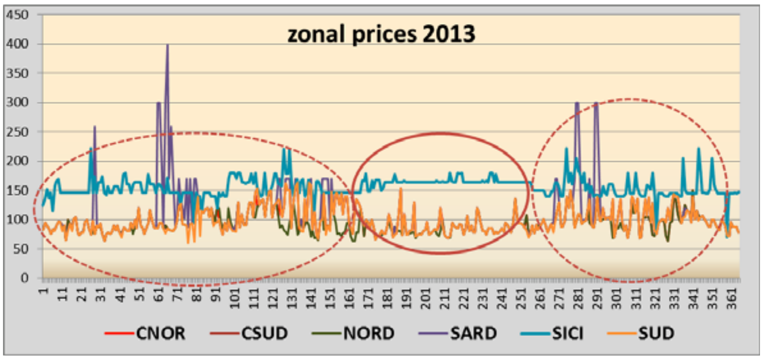
When intra zonal power flows are lower than the transmission limits the market clearing price is the same in the zones (*one single price*) resulting from the intersection between demand and supply across zones. In this case the market area is one, identified by the entire system. On the other side, when the intra-zonal flows are higher than the transmission limits the market area – and the market price - splits in as many zones / (*zonal*) prices as the number of time in which the transmission limits are not respected plus one[1]. In those circumstances, the excess of demand in one zone, which cannot be satisfied by cheaper power from the neighbouring zone because of bottleneck in the transmission line, is covered by the supply in the same zone, where generation costs are higher and available technologies are generally from fossil fuels.

The paper is organized as follows. In the first part we analyse the private value of two storage project investments located in two different areas of the country, SICI and ROSN. In the second part we study the environmental implications of the storage plant operation. In the discussion of results we analyse the role of electricity prices as adequate market signals of environmental impact of the investment projects. Further we conclude.

2 METHODOLOGY

The analysis is based upon a price-taker model under perfect price forecasts simulating the dispatch of a marginal pumped-hydro storage plant solved with CPLEX 12.1 under GAMS. The case study is applied to two zones of the Italian power market (IPEX). SICI denotes the island of Sicily, and the pole of limited production, Rossano (ROSN), that is located in SUD and connects the island to the mainland through a submarine cable. This case study is of particular interest because SICI and SUD feature the highest and most volatile price levels in the country (Fig. 2). Additionally, the potential of wind and solar generation (Šúri et al.2007) makes this region a future leading producer of renewables in Italy.

Figure 1. Italian zonal prices in2013



The storage plant located in each zone maximizes arbitrage profits from zonal price spread between off and on peak hours. The higher is the volatility of prices, the higher are private profits for the storage investor.

In the first part of the study we assess the profitability of the storage investment projects. We assume 2013 as the reference year for the NPV analysis, so that profits and costs flows during the entire investment period are the same as in 2013.

[1] For instance, if the transmission limit is not respected once in one hour, the market splits into two zones, each one with a zonal clearing price.

The investment analysis considers the operating profits (REV-CST-OPEX), where OPEX are the operating costs and (INV0) the capital investment costs. The NPV formula (1) is divided by the annual electricity sold on the market which returns results in terms of €/MWh.

$$NPV = \frac{\sum_{t=1}^{T}\left[\left(REV_t - CST_t - OPEX_t\right)/\left(1+r\right)^t - INV_0\right]}{\sum_{t=1}^{T}\left[EG_t / \left(1+r\right)^t\right]} \tag{1}$$

Where REV_t is the annual revenues from power sales; CST_t is the annual costs from electricity withdraw (charged) from the grid; $OPEX_t$ is the annual operating expenditure from fixed and variable O&M costs; INV_0 is the initial cost of investment; EG_t is the annual electricity sold on the market; r is the annual discount rate; T is the economic life time of the investment project.

In the second part we assess the environmental impact of storage operation on CO2 emissions and on the integration of renewable generation. We consider the power charged and discharged, the marginal technologies setting the price in correspondence of each hour of operation (GME SpA Online) and the carbon content associated to the marginal technology (kgCO2/MWh) (UNFCCC, 1.12.2014 Online). During operation the storage displaces the marginal technology during discharging hours with power previously stored. This power substitution directly affects the level of greenhouse gases in the system. The net environmental effect is determined by the difference in kg of CO2 contained in the power charged and displaced during discharging hours. Table 1 gives a numerical example of the applied methodology.

Table 1. Example of Net CO2 emissions from PHS operation

Charging hour	Mg technology (kgCO2/MWh)	discharging hour	Mg technology (kgCO2/MWh)	Net CO2 emissions (kgCO2/MWh)
H1	+1MW Other RES (0)	H2	-1MW Gas turbine(-90)	-90
H4	+1 MW Hydro (0)	H3	-1MW Oil (-70)	-70
	0		**-160**	**-160**

Note: In this example CO2 emissions decrease and the share of RES increases. During charging hours the storage integrates GHGs/RES (the variation is positive (+)); during discharging hours it substitutes the carbon content/RES share of the available marginal technology with the one that was integrated during charging (the variation is negative (-)).

The same methodology is applied to determine the renewable generation that is integrated/displaced during storage operation.

3 THE CASE STUDY

In this case study we simulate the operation of a pump-hydro storage plant with 280 MW of power and 8 hours of storage capacity[2] in each zone (Table 2).

[2] According to some studies (Gimeno-Gutiérrez et al. 2013) on the technical potential and feasibility of PHS projects in 28 countries in Europe, it is realistic plan to think of the technical feasibility of this type of investment in the 2 considered geographical zones in Italy.

Table 2. Pump-hydro storage plant. Technical and economic parameters.

CAPEX	2010	OPEX	2010
power capacity (€/kW)	1850	fix (€/kW.y)	6
energy capacity (€/kWh)	230	variables (c€/kWh)	0.0215

Source: ETRI 2014

The storage plant maximizes temporal arbitrage profits by buying power when prices are low and selling it when they are high. The storage plant does not influence price levels either the merit order of the technologies that sets the marginal price. The effect of storage operation is to shift power from one time to the other when production is economically more efficient. The PHS can be therefore considered as a marginal unit added to the existing technology portfolio of the zone with no impact on market forces.

3.1 Results of the investment analysis of private profits

The tables below contain the results of the operation of both investment projects for the year 2013, which is the reference year for the investment assessment (Table 3). We assume that profits and costs flows during the economic life of the investment are the same as in 2013.

Table 3. Results of the storage operation

Results	SICI	ROSN
operation (charging/discharging) (MWh)	430,351	378,917
operating revenues (from discharging/production)	26,197,618.67	14,333,688.66
operating costs (from charging/pumping)	14,420,334.95	7,759,020.25
operating profits (from discharging/production)	11,777,283.72	6,574,668.40
CAPEX (280 MW)	518,000,000	518,000,000
variable OPEX	92,525	81,467.15
fixed OPEX (€/kW.y)	1,680,000	1,680,000

Results of the NPV analysis show negative profits for storage investments both in SICI and ROSN (Table 4).

Table 4. NPV results for SICI and ROSN

Reference year	SICI NPV (€/MWh)	ROSN NPV (€/MWh)
2013	-88.55	**-112.06**

3.2 The environmental impact assessment of storage operation

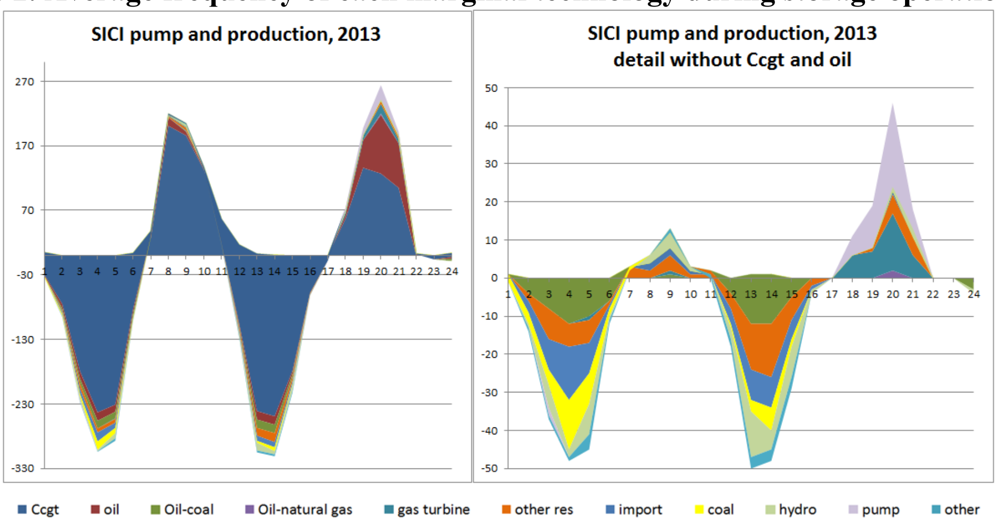
We conduct an environmental impact analysis of storage operation to assess if the cost effective load shifting of the project (buying when prices are low and selling when prices are high under technical constraints), has an effect on the net CO2 emissions and renewable power integration.

The profits maximizing behaviour of the project is driven by electricity market prices under specific technical constraints of the plants (power capacity and minimum/maximum power charge and discharge for the storage plant). The environmental impact of the plants operation is strictly related to the carbon print of the energy mix in each zone. In particular, the investment plants in the two zones act as price taker in the market therefore they are remunerated at the market clearing price in each zone. To assess the environmental impact (in terms of change in CO2 content and renewable integration) of projects operation we refer to the marginal technology setting the price in each hour, which is measured by the Marginal Technology Index (MTI)[3].

For each storage plant, we calculate the carbon impact of each MWh of pumped power (which is to be considered as a marginal increase of demand of power in the system, not affecting the level of market prices) by associating the CO2 content (kgCO2/MWh) of the marginal technology during each pumping hours. This amount is subtracted to the CO2 content corresponding to the marginal technology during discharging hours to calculate the net CO2 impact. The discharged power is to be considered as the increased power supply in the market from the storage that replaces the power from the technology available at the margin during the same hour. Also the storage operation should be considered as a shift of power production from one time during the day/week/year to another when the cost of electricity is lower.

Applying a similar methodology we assess the impact of storage operation in terms of integration of renewable generation. The RES integration effect is calculated as the MW of power from renewable energy integrated into the power system during storage charging, as if the storage operation would increase the demand of power during those hours supplied by renewable sources.

Figure 2. Average frequency of each marginal technology during storage operation, 24h



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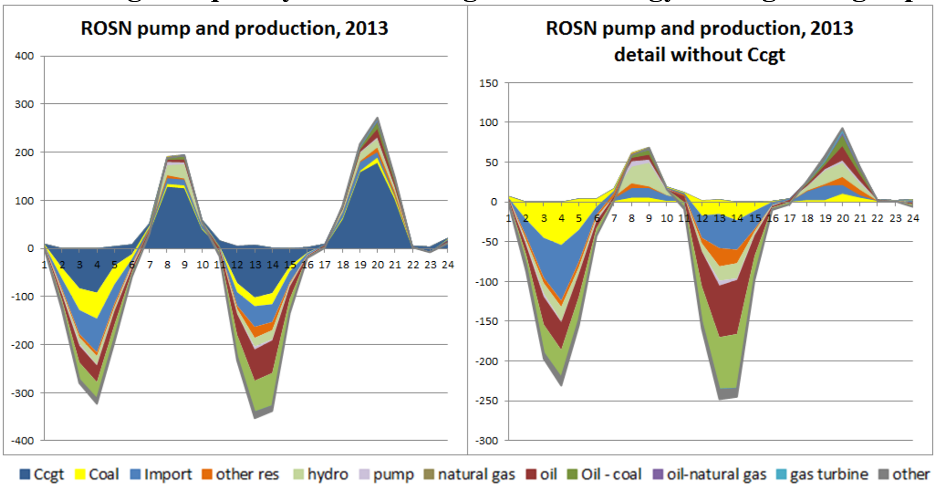
[3] This data is available from the IPEX web site, GME SpA, under *historical prices*.

Figure 3. Average frequency of each marginal technology during storage operation



Source: own elaboration on results

To estimate the CO2 net effect, we calculate the difference between the carbon content (kg CO2/MWh) of the marginal technology during charging hours and during discharging hours[4]. In this way we assume that the storage shifts emissions from hour t to hour t+1, while substituting power withdrawn at time t with the power that would have been supplied by the marginal technology in correspondence with discharging hour in t+1. Table 5 contains the assumptions on the specific CO2 content for each marginal technology.

Table 5. CO2 emissions by generation technologies

marginal technology	CO2 and other GHG emissions (kg/MWh)
Other	- (a)
Coal	860 (b)
Ccgt	370 (c)
Foreign zone	- (d)
Other renewables	0 (e)
Run of the river	0 (f)
Basin hydro power plant	0 (g)
Pumped storage	0 (h)
Natural gas	400 (i)
Fuel oil	670 (l)
Oil-coal	765 (m)
Oil-natural gas	535 (n)
Gas turbine	569 (o)

(a, d) For those two cases we have attributed 0 kg CO2/MW because
(b, o) Generazione elettrica, 2002-2003
(c, i, l) IEA ETSAP - Technology Brief E02 – April 2010 - www.etsap.org "Gas Fired Power"
(e) *Other renewables* includes all renewable generation technologies (wind, solar and geothermal). PV and wind plants contribute to CO2 emissions only during the building phase of the plant. Those emissions are not considered in the environmental impact assessment here though. The CO2 content showed in the table refers to the emission factor of geothermal generation only. This assumption has the effect of overestimate the total cost for CO2 in the system. Source: http://www.eia.gov/tools/faqs/faq.cfm?id=76&t=11 and http://edis.ifas.ufl.edu/fe796#TABLE_2

[4] The information on the marginal technology setting the price during each hour comes from the data available on GME SpA web site. www.mercatoelettrico.org

(f, g) We assume an average between 10 and 30 gr CO2/kWh (the footprint of hydroelectric power is made for the biggest prat of land and water resource use. In addition to this, hydroelectric power also emits GHGs, which are calculated to be between 10 and 30 kg/MWh) http://www.edfenergy.com/energyfuture/energy-gap-climate-change/hydro-marine-and-the-energy-gap-climate-change http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-hydroelectric-power.html (h) Here we consider only greenhouse gas emissions from variable components relative to the operation and maintenance of the plant (1.8 tonnes of CO2/GWh) and the net efficiency (net energy ratio equal to 1.35 times source emissions). Denholm (2004). (m) average oil and coal (n) average oil and gas

Tables 6, 7 contain the results of the environmental impact analysis of storage operation in SICI and ROSN in 2013 under assumption that the carbon content of each MW of power charged and discharged is evaluated at 0.015€/kgCO2 and each MW of renewable energy integrated in the system is awarded of 80€, which corresponds to the average price of green certificates in the Italian market in 2013 (GME SpA online).

Tables 6 and 7 show the CO2 impacts (kg CO2/MWh) and costs (€/kgCo2) together with the change in the level of reneable generation in the system given by the difference between of power pumped (PUMPa) and power discharged (PRODb).

Table 6. Environmental impact of storage operation in ROSN

ROSN	CO2 content (kg CO2/MWh)	cost for CO2 (0.015 €/kgCo2)	RES integration (MW)	benefits from RES integration (80 €/MW/ green certificate)	Net impact
PUMP (a)	(-) 80,121,242	(-) 1,201,818	9,915.29	793,223	-
PROD (b)	(+) 56,676,835	(+) 850,152	-	-	-
Net impact (b-a) [5]	-23,444,407	**-351,666**	9,915.29	**793,223**	**441,557**

Table 7. Environmental impact of storage operation in SICI

SICI (2013)	CO2 content (kg CO2/MWh)	cost for CO2 (15 €/tonnes CO2)	RES integration (MW)	benefits from RES integration (80 €/MW/ green certificate)	Net impact
PUMP (a)	85,162,366	1,277,435	6,843.529	547,482	-
PROD (b)	80,174,670	1,202,620	-	-	-
Net impact (b-a)	-4,987,696	**-74,815**	6,843.529	**547,482**	**472,667**

Tables 8 and 9 show additional details of the storage operation during 2013, including the maximum, minimum and average price during charging and discharging activity, the frequency associated to each marginal technology.

Table 8. Max/Min/Average market price during storage charge/discharge and frequency in correspondence with each marginal technology. ROSN 2013

ROSN	max price (€/MWh)	min price (€/MWh)	average price (€/MWh)	frequency (% of operation)

[5] CO2 emissions considered for the production operation of storage are to be interpreted as avoided CO2 from storage operation (positive effect of storage). CO2 emissions from pumping activities should be interpreted as increased demand of power associated to the corresponding technology (negative effect of storage).

	PROD	PUMP	PROD	PUMP	PROD	PUMP	PROD	PUMP
Other, Foreign zone	118.61	75.94	10.00	0.00	77.54	34.85	4.56%	21.93%
Pumped storage	100.00	60.52	52.25	15.32	75.73	41.24	1.10%	1.03%
Run of the river	130.00	65.00	40.00	4.00	80.89	37.43	1.75%	1.62%
Basin hydro power plant	150.00	61.69	20.00	9.01	76.60	40.13	3.96%	3.84%
Other renewables	130.40	56.77	10.00	0.10	81.35	21.29	3.04%	4.75%
CCGT	150.00	76.05	0.00	0.00	82.09	46.13	80.76%	34.41%
Gas turbine	92.51	41.10	84.00	30.00	87.39	36.47	0.23%	0.27%
Oil-coal	163.05	60.01	0.00	0.00	92.96	36.42	2.03%	18.58%
Coal	163.00	52.77	0.00	0.00	83.02	32.98	2.26%	13.56%
Oil-natural gas	158.23	-	85.00	-	136.25	-	0.23%	-
Fuel oil	156.36	-	143.67	-	150.02	-	0.09%	-

Table 9. Max/Min/Average market price during storage charge/discharge and frequency in correspondence with each marginal technology. SICI 2013

SICI (2013)	**max price (€/MWh)**		**min price (€/MWh)**		**average price (€/MWh)**		**frequency (% of operation)**	
	PROD	**PUMP**	**PROD**	**PUMP**	**PROD**	**PUMP**	**PROD**	**PUMP**
Other, Foreign zone	115.00	66.00	48.50	0.00	72.37	33.79	0.42%	3.85%
Pumped storage	205	62.15	141	59.11	177.62	61	3.03%	0.10%
Run of the river	205.01	85.98	40.00	4.00	104.99	50.12	0.63%	1.66%
Basin hydro power plant	68.37	72.67	20.00	9.01	43.35	46.70	0.28%	0.62%
Other renewables	200.00	120.00	0.00	0.00	121.78	29.90	1.62%	2.95%
CCGT	164.06	121.05	0.00	0.00	124.42	67.14	74.23%	84.65%
Gas turbine	221.90	30.00	152.21	30.00	170.83	30.00	2.46%	0.05%
Oil-coal	-	42.02	-	14.07	-	34.80	-	3.56%
Coal	-	50.01	-	0.00	-	28.07	-	2.14%
Oil-natural gas	158.23	-	146.26	-	152.25	-	0.14%	-
Fuel oil	-	149.69	-	145.23	-	146.72	-	0.43%

3.3 The NPV analysis when environmental impacts are included

The two environmental effects (integration of renewable generation and change in the level of CO2 amissions) are included in the NPV assessment together with the private benefits from storage operation. The inclusion of environmental impacts in the investment assessment contributes to a better evaluation of the investment project. Results show an improvement of the NPV (from NPV(1) to NPV(2)) although without changing the business case for the storage investment which remains non-profitable in both zones (Table 10).

Table 10. NPV assessment for storage investment in SICI and ROSN when environmental impact is included.

		SICI			ROSN		
Reference year	**investment costs in PHS**	**NPV (1) (€/MWh)**	**NPV (2) (€/MWh)**	**variation (%)**	NPV (1) (€/MWh)	NPV (2) (€/MWh)	variation (%)
2013	519,772,525	-88.55	-87.63	**1.04%**	-112.06	-111.09	0.87%

4 DISCUSSON

The negative environmental impact of storage operation can be explained in part by the net loss due to a round trip efficiency lower than 1 (85% in our model) (Denholm 2004). This means that each MW of power pumped corresponds to 0.85 MW of power produced. The 15% of the power pumped represents a net cost/loss.

To investigate further this aspect, we run the model a second time assuming no power losses due to inefficiencies in the storage operation and we set the level of roundtrip efficiency equal to 1. Each MW of power pumped is discharged into the grid without losses. As expected, results show an equal level of charged and discharged power in both zones. The environmental impact analysis shows that CO2 emissions are still positive although lower compared to the case of 85% roundtrip efficiency.

CO2 emissions increase in the case of storage, although this is compensated by the positive impact in terms of increased share of renewable integration. The result on CO2 emissions can be explained in part by the efficiency loss due to a round trip efficiency lower than 1, 85% in our model (Denholm 2004). This means that each MW of power pumped corresponds to 0.85 MW of power produced. The 15% of the power pumped represents a net cost/loss

The second possible explanation to our results on the environmental impact of storage can be found in the (wrong) signals given by electricity prices, which do not properly reflect the carbon content of the generation.

This comment explains only in part the results. In principle for higher levels of the roundtrip efficiency this negative impact of storage operation on CO2 emissions should reduce or disappear. This would not be the case though when the energy mix of the market we are studying is dominated by thermal power, like it is the case of Italy. To investigate further this aspect, we run the model a second time only for the zones of SICI and ROSN, which are our focus on this study, and we set the level of roundtrip efficiency equal to 1. Each MW of power pumped is discharged into the grid, shift to another time, without losses. As expected results show an equal level of charged and discharged power in both zones. The environmental impact analysis shows the same negative effect on CO2 emissions from storage operation in both zones though. Level of emissions in the system is higher with respect to the case of no storage. This result allows us for some further speculation on the role of flexibility options in the power market. The techno-economic optimization of the storage device, despite being cost-effective, does not guarantee optimality in terms of environmental impact. According to our further analysis, and with the support of some interesting research by other authors (Vespucci et al. 2013, Gianfreda et al. 2013) this is to be attributed to the fact that although storage responds to price signals according to cost-effective criteria, prices seems not to be affected by fuel and carbon price levels, thus reflecting an environmental externality in the market. This result opens the discussion to a wide range of further aalysis on the level of competition in the Italian power market. Consider that electricity price levels in the Italian power market are quite high, and taken into account that “dirtier” and more expensive technologies often set the price in the merit order, the power price doesn’t seem to reflect the carbon content of these more expensive sources of power. This could be considered a source of inefficiency due to operators exercising power in the market.

5 Public support to storage investments

Further elaborations show that subsidies to storage operation in the form of feed in MW of power operated (charged and discharged) during each hour of operation may have some impact in those regions where the storage plant operates for a high number or hours. In the selected zones, such a public support measure would not change the business case of the two storage project investmens, which will remain non profitable. In the same way, a higher value of green certificates would have a small impact on the economics of the investment, while a more stringent carbon policy (higher carbon price) would accrue the negative impact of storage operation interms of CO2 emissions. On the other side, we notice that improvements in the costs of technology together with a longer economic life of the plant would both have a relevant impact on the business case of the investment.

6 CONCLUSIONS

The ambitious targets on CO2 emissions set by the European Commission by 2050 towards a decarbonised and efficient energy sector call for adequate system analysis. This study shows negative NPV values for the investment in PHS technology in two Italian zones. The analysis of the private value of the investment should be accompanied by the assessment of its social value to contribute to a more complete evaluation of the investment projects. In fact the net present value of both PHS investments increases although without changing their business case which remains non-profitable for the storage plants.

Policy incentives in support to the storage technologies would intervene if the social value from the storage investment would at least cover the negative results of the private profits assessment. We show that the operation of a PHS, despite being costs minimizing, does not guarantee optimality in terms of environmental impact. According to our further analysis, and with the support of some interesting research by other authors (Gianfreda et al. 2013) this result can be attributed to the fact that although storage responds to price signals according to cost-effective criteria, prices do not reflect the carbon content of the power sector, which is dominated by thermal generation, thus not fully reflecting the environmental externality in the market.

(Zachmann 2013) identifies a non-linear relationship between electricity prices and fundamental drivers such as coal and natural gas as well as carbon emissions allowances, thus affecting market efficiency. Indeed if electricity prices are not affected by fuel and carbon prices in thermal dominated market, market pricing will not be based on marginal costs (which include carbon costs) and cannot be considered as appropriated signals of the environmental impact.

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Impact of the economic recession on electricity demand sensitivity to temperature in Spain

Luis Villafruela Arranz[1], Mauricio Remacha Moro[2], Félix Martínez Casares[3]

[1] *Luis Villafruela Arranz, Red Eléctrica de España, Pº del Conde de los Gaitanes 177, Alcobendas, Spain, lvillafruela@ree.es*
[2] *Mauricio Remacha Moro, Red Eléctrica de España, Pº del Conde de los Gaitanes 177, Alcobendas, Spain, mremacha@ree.es*
[3] *Félix Martínez Casares, Red Eléctrica de España, Pº del Conde de los Gaitanes 177, Alcobendas, Spain, fmartinez@ree.es*

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ABSTRACT

Red Eléctrica de España (REE), the Spanish TSO, is committed to elaborate and publish statistics of the Spanish electric system. Among the most known statistics REE published it is the electric energy balance, in which the daily demand of electricity is computed. Together with the energy balance and the electricity demand evolution (compared with the same period of the previous year), REE publishes the evolution of the electricity demand adjusted by the influence of the evolution of the temperatures as well as the composition of the calendar. Once the demand evolution has been cleaned up of the influence of these random variables, the adjusted demand should be the electricity demand due to the evolution of the economic activity with the advantage that is published at daily level and thus it is a good advanced index of the evolution of the economy. To make these adjustments, many years ago, REE developed an econometric model which has been improved continuously.

Taking into account that the consumption of electricity reflects the situation of the society, we consider that the recent recession of the Spanish economy has got a real impact over the electricity demand. The impact of the recession has been not only in the consumption level, but also in the sensitivity of the consumers to temperature changes. To make this analysis we have used the present version of the model and changes in the behavior of electricity consumption have been identified and quantified.

KEYWORDS: electricity, demand, temperature, sensitivity, recession.

1 INTRODUCTION

Red Eléctrica de España (REE), the Spanish Transmission System Operator (TSO), has got a broad experience in the electricity demand (from now on, demand) analysis and modelling. This experience covers from the very short term hourly load forecasting up to long term forecasting (30 years) on the basis of the expected evolution of a set of explanatory variables.

One significant part of these analysis is the Daily Balancing, which is published every day in REE web page (www.ree.es), and is one of its most popular products. In addition of the production split by fuel types, the Daily Balancing presents the demand evolution from two perspectives: the gross growth and the adjusted growth compared with the same period of the previous year.

The adjusted demand growth represents the evolution of the demand compared with the previous year in which the different composition of the calendar, as well as the differences in the temperatures have been taken into account. Once the effect of these two random variables has been filtered, we can say that the evolution of the demand (that is, the adjusted demand growth) is due, mainly, to the evolution of the economic activity.

With the aim to perform the kind of analysis mentioned above, REE developed an econometric model that explains the evolution of the daily demand as a function of a set of typologies of days basically characterized according with their working day or holyday nature, as well as a response function of the demand to temperature changes that distinguishes cooling and heating effects.

The original model that is presently working in REE was developed in 2004 with the collaboration of the "Instituto Flores de Lemus" from the University Carlos III of Madrid. This model has been updated and improved continuously since then and is the base of the analysis presented in this paper.

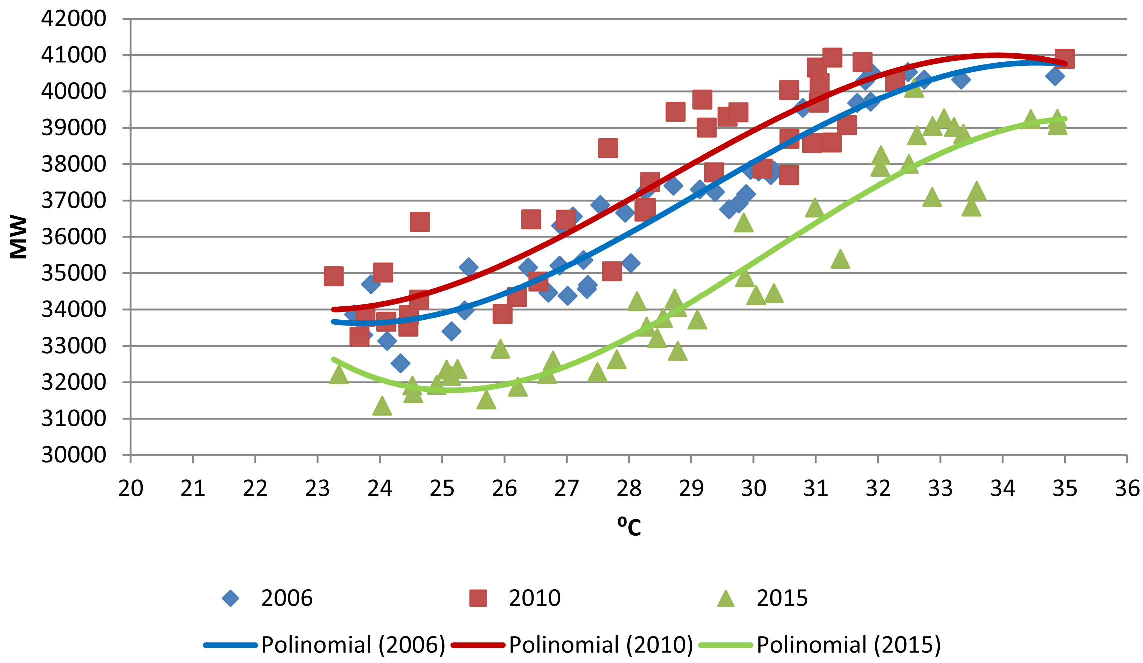
In this process of updating the model, slight but continuous changes in the parameters of the demand-temperature response function had been detected showing, in general, less sensitivity to temperature variations than in the past.

In the figure 1 the relationship between the maximum hourly demand of the day and the maximum temperature, measured in Celsius degrees, during the summer period is showed for the years 2006, 2010 and 2015. The selection of these years to make the comparison is not arbitrary, in fact these years have been chosen because they approximately have the same level of activity, using the Gross National Product (GNP) of the country as a proxy variable of the activity level.

The basic data of the figure are the following:

- In 2006 the maximum demand of the period was 40.524 MW with a maximum temperature of the day of 32.5ºC.
- In 2010 the demand was 40.934 MW with a temperature of 31.3ºC. This is the maximum historical hourly demand in summer period until the present.
- In 2015, during a heat wave, the demand was 40.096 MW with a temperature of 32.6ºC. Be aware that the temperature is similar to the temperature in 2006 and 1.3ºC greater than the temperature of the day of the maximum historical hourly demand.

Figure 1: Maximum Hourly Demand vs. Temperature in Working Days of May, June and July



The main conclusion that can be shown in the figure is that for the same temperature the level of the demand has changed. Presently the consumption per degree is lower than in the past. Many reasons can be found for this changes like efficiency improvements, habits of use modifications and so on, but we consider that is the impact of the past economic recession is the most important of them, especially when in 2015 the GNP is still a 5.4% lower than in 2008, and 2015 will be the second year with positive growth after the recession.

In conclusion, we think that the economic recession has got a real impact over the sensitivity of the demand to temperature and this change has to be reflected in the model we use to compute the adjusted demand growth. Estimate the impact of the change has got an influence on the statistics we published because we split the demand growth in the three main effects mentioned above what if means that a good estimation of the temperature sensitivity will result in a better estimation of the adjusted demand growth.

In section 2, a brief description of the present version of the model specification will be showed. In section 3 we will analyze the problem of structural change and the approach that we have followed. And in section 4 we will present the final specification of the model including the impact over the temperature sensitivity.

2 BRIEF DESCRIPTION OF DAYLY DEMAND MODEL

In the previous section, we mentioned that REE had specified a demand model, developed with the aim to explain the evolution of the daily demand, distinguishing the three main factors that can influence on it: influence of the calendar composition, evolution of temperatures and economic activity. That is, it is an explanatory model and not a forecasting model, which has determined its modelling strategy. Another constrain to the modelling strategy was that we wanted to explain the evolution of the demand for all available daily data history; from 1990 until the present.

The final specification of the model is the following:

$$\Delta lnC_t = \omega'\Delta L_t^* + \beta^F \Delta HDD_t + \beta^C \Delta CDD_t + \alpha'\Delta A_t + \theta_1 \hat{u}_{t-1} + \cdots + \theta_p \hat{u}_{t-p} + a_t$$

Whereas;

- Δ represents the regular difference: $\Delta X_t = X_t - X_{t-1}$
- lnC_t is the logarithm of the daily demand
- L_t^* denotes the expanded vector of the days typology
- HDD_t, heating degree days of the maximum temperature of the day.
- CDD_t, cooling degree days of the maximum temperature of the day.
- A_t, outliers identified in the modelling processes.
- $\theta_1 \hat{u}_{t-1} + \cdots + \theta_p \hat{u}_{t-p}$, is an autoregressive process to take into account the short term dynamic of the demand.

2.1 Days typology

Although it is not the purpose of this working paper to give a detailed explanation of the process in which we have identified the typology of days, in order to have a global perspective of the model, following we will show a brief description of the typology of days that we have set in the model. It is also necessary to mention that it is specified one dummy variable per day typology up to a total of more than one hundred variables, taking into account the day of the week and if the holyday is located before or after a weekend. In general, the key days and periods identified are the following:

- Normal day: from Tuesday to Thursday in months with limited influence of the temperature (October and May).
- Weekly seasonality: different one per month.
- Isolated holydays: may 1th, August 15th, October 12th and November 1th.
- Regional holydays.
- Vacation periods: Eastern, beginning and end of August, Holydays 6th and 8th December and Christmas vacations.

2.2 Temperature

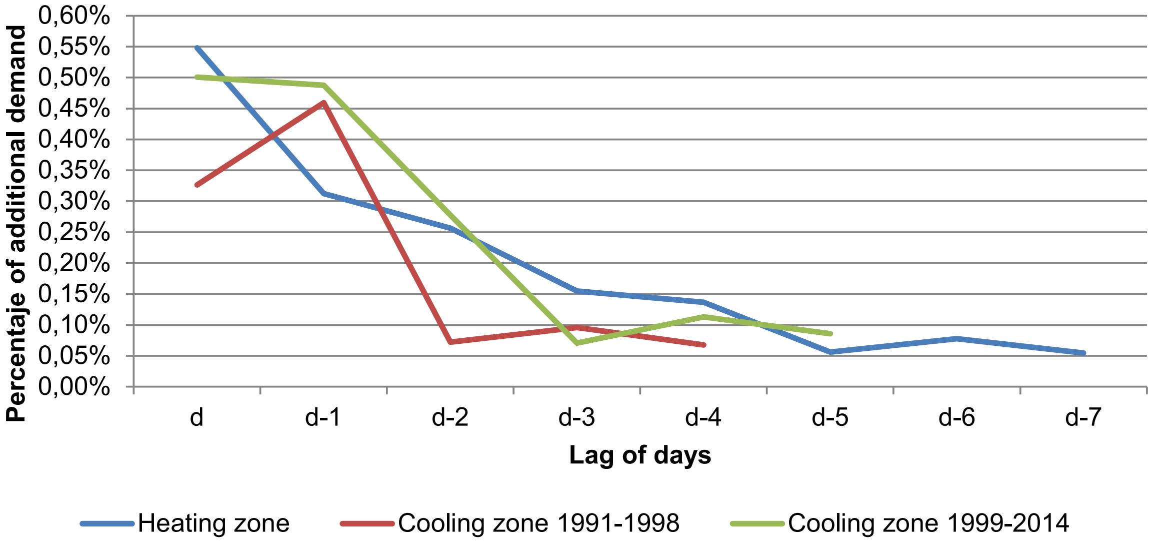
The background information consists on the maximum daily temperature metered in each capital province, weighted by the annual demand of the province. Once the temperature basic indicator was constructed, two question appeared to be solved in the modelling strategy. The first one was to determine the temperature threshold from which it has influence over the demand, that is, to define the cooling and heating zone; and the second one was to estimate the dynamic dependency of the demand to short term temperature evolution or, in other words, to find the way to include in the model specification the influence of the temperature of the previous days over the demand of the present day, that is, the persistence of the influence of the temperature.

The strategy of modelling in the both questions mentioned in the preceding paragraph was an iterative process in which the specification of the model that minimizes the residual standard deviation adjusted by degrees of freedom, and maximizes the significance of the associated parameters was chosen. In this iterative process, we also found that there was a structural change in cooling associated variables. The change was set in the year 1999 and is a consequence of the high penetration of air conditioning systems during the expansion period of the Spanish economy, which implies that cooling sensitivity parameters are lower before 1999 than subsequent years.

Finally, the influence of the temperature specification over the demand was:

- Two threshold were identified for the maximum temperature of the day: temperatures lower than 20ºC for the heating zone and temperatures higher than 23ºC for cooling zone. In addition, the range from 22ºC to 17ºC for heating zone, and 20ºC to 25ºC for cooling zone was tested.
- Regarding the dynamic response of the demand to temperature, different number of lags were tested in order to determine de influence of the temperature of the preceding days over the demand of the day "d". In both cases, heating and cooling zone, the influence of the previous days is almost declining (except for the cooling zone before 1999) but the number of representative lags are quite different. In figure 2, the sensitivity parameters of the temperature are showed and the y-axis should be read like the percentage of additional demand due to temperature effect (per degree day) over the demand without influence of temperature. In the heating zone, the temperature of the seven precedents days has influence over the demand of the present day, on contrary, the number of significant lags for cooling zone are 5 days after 1999 and 4 days before that year, being remarkable that before 1999 the influence over the present demand of the temperature of the day before is greater than the influence of the present day temperature.

Figure 2: Present Parameters of Temperature Sensitivity



3 ESTRUCTURAL CHANGE IN SENSITIVITY OF TEMPERATURE PARAMETERS

The sensitivity of the demand to temperature presented in the previous section or the increase of the demand per degree-day, is a consequence of the confluence of two main factors:

- The comfort threshold, that is, the temperature from which the consumer switches on their equipment (heating or air conditioning) to reach a certain well-being.
- The existing stock of equipment. This stock can vary because an increase or decrease of the number of households or companies, or because the existing ones invest in new equipment. In any case, the stock variation is associated with the evolution of the economic cycle.

The evolution over time of these two main factors is not isolated of the economic situation, in the sense that if the activity level wealth increase, more equipment will be acquired and even comfort threshold would be modified. Following this point, the hypothesis to be checked is that if the strong economic recession suffered by Spanish economy has got an impact over the sensitivity of the demand to temperature variations.

The difficulty of determining if the response function has shifted is not only to determine the change itself but identify when, this is the mayor problem. To do that, the procedure we will follow is to stablish the hypothesis that the change in the response function is discrete, that is, the change occurs at a particular moment in time. With this approach, the date of change has to be determined endogenously, using the own information included in demand evolution. The reason to follow this approach is because we have not identified an exogenous variable (with monthly or daily frequency) to let us know, approximately, the moment of change.

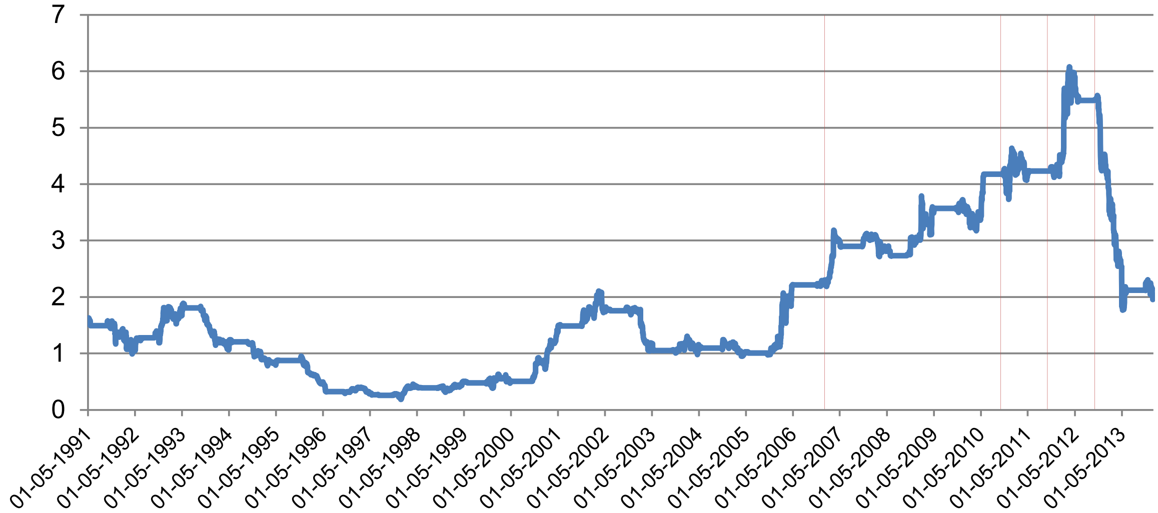
In the analysis of structural change, we have considered the year 2008 as starting point, with the aim to estimate the response function existing before the "official" start of the economic crisis, and check these values with the estimated values in the subsequent period. Methodologically, we will use the Quandt-Andrews test, which is based on Chow test, and let us analyze, conjointly, both periods; before and after the breakpoint.

3.1 Heating response function

The Figure 3 represents the evolution of the L-R Statistic when the breakpoint is changed every day. From this analysis, we can deduce that the heating response function has changed along the period, being March 19th of 2012 the day in which the value of the statistic is maximized. To fix exactly this date to set the breakpoint could be considered too much precise, especially when there is not a relevant event from the economic point of view to justify it.

Analyzing the evolution of the statistic, we can observe that until the winter 2007-2008 the values are lower than the critical value (2,1), so we can reject the hypothesis that the response function has changed. From this moment, the value of the statistic increase continuously until the maximum indicated in the paragraph above is reached, with clear steps at the beginning of the winter 2009-2010, 2010-2011 and 2011-2012.

Figure·3: Heating response function. L-R Statistic



Based on the analysis on the previous figure, it seems to be conclusive that there is a change in heating response function but the question now is to determine exactly when the change has been produced. The final selection of the breakpoint will be done in the conjoint estimating process of the model where we will evaluate three alternative response functions for the periods mentioned above, and the response function which minimize the errors of the model will be selected.

3.2 Cooling response function

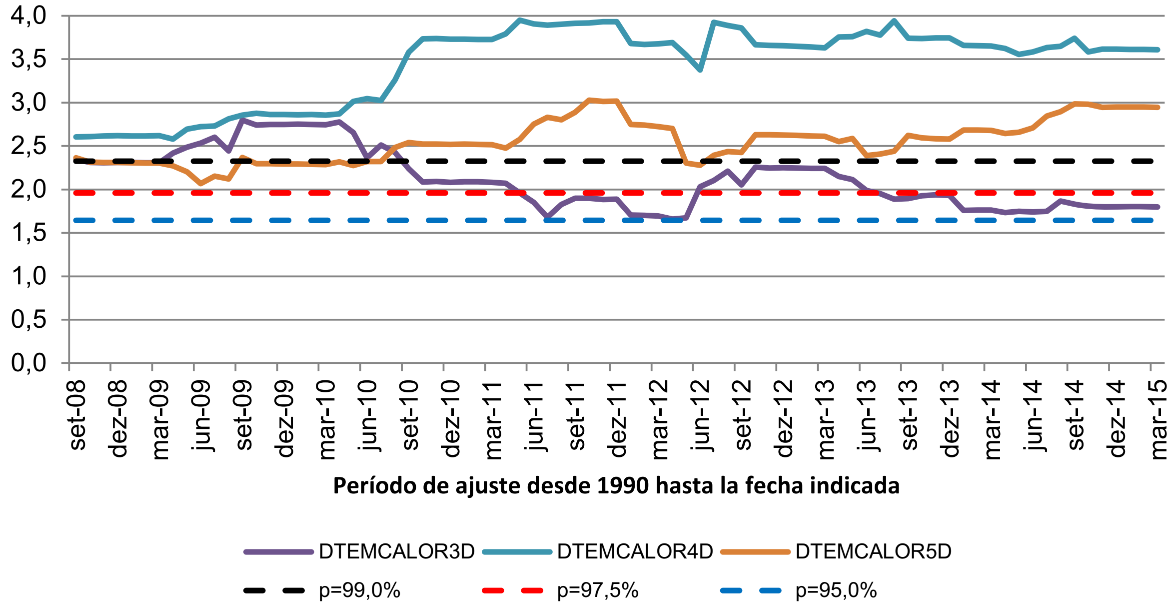
The same analysis of the previous subsection for heating response function was done for the cooling response function but, in this case, the results obtained were not so conclusive than in the heating function, what would mean that the cooling response function would have remained unchanged.

However, if it has been obtained a positive result for the case of heating response function, and taking into account the socio-economic circumstances of the country, it would be reasonable to consider that a similar situation could occur for cooling even though the test was not detected it. For this reason, in this case the strategy was changed, and a new approach was set and the significance of the associated parameters of the cooling response function was analyzed.

In this sense, to analyze the evolution of the signification level of the parameters that define the cooling response function, it has been proceeded to adjust the present model using moving windows of the adjustment period.

In figure 4 it is represented the evolution over the time of t-statistic of the response function parameters. In the figure is only included the statistic of the associated parameters to lags “d-3”, “d-4” and “d-5” because the other lags, as well as the temperature of the present day are highly representative. Besides t-values, it is also included the critical values taking into account different requirements levels: 99.0%, 97.5% and 95.0%.

Figure 4: Significance evolution of cooling response function parameters



Being very restrictive when accepting the significance of one variable, a 99% probability was selected. In this case, the variable that takes into account the influence of the temperature of the day “d-3”, lost their significance from 2010 summer. The loss of relevance of “d-3” variable has a second implication and is that the hypothesis of continuity of the response function is assumed, the significance loss of this variable implies that the influence of the days “d-4” and “d-5” should be dropped from the response function. Obviously the previous argument is very weak from the statistical point of view, and it would only serve as a hint of possible changes of the response function, but this point should be verified in the global estimation of the model.

4 FINAL ESPECIFICATION OF THE MODEL

In the previous section the possible existence of breakpoints in the response function of the demand to temperature variations was analyzed, consequence of the changes in the Spanish society because the impact over the demand of the economic recession. As a result of the analysis, different possible breakpoints were identified and whereas in the case of heating response the existence of change breakpoint is very clear, in the case of cooling response function were not conclusive.

The definitive selection of the breakpoints, as well as the existence of breakpoint in cooling zone, has been done in the conjoint adjustment of the model. Six equations were estimated in total, consequence of the initial breakpoints identified. This is:

- Heating; beginning of winter 2009-2010; 2010-2011; 2011-2012.
- Cooling; without breakpoint in all the period, and a breakpoint at the end of the summer 2010.

The main statistics obtained in the estimation process is presented in annex 1, being the main conclusions the following:

- All the alternatives that consider a breakpoint of the response functions improve the present adjustment of the model, so it is possible to accept the hypothesis that a change in the shape of the response function has happened or it could be said that the behavior of the consumers as regards as their response to temperature have been modified.
- The shape of heating response function has changed and in the new adjustment of the model only have influence the three days before (figure 5). Indeed, in the option of breakpoint at the beginning of the winter 2011-2012, it only has influence the temperature of the present day.
- The cooling response function would have also changed, and the temperature of the present day and the day before have influence now, with the particularity that the influence of the temperature of the day before is greater than the influence of the present day (notice that is a similar shape than the response function prior to 1999). This point would be indicating that the response of the consumers is more instantaneously than in the past, and the building heating effect of the day before has more influence than the temperature of the present day. Figure 6.

Figure 5: New heating response function.

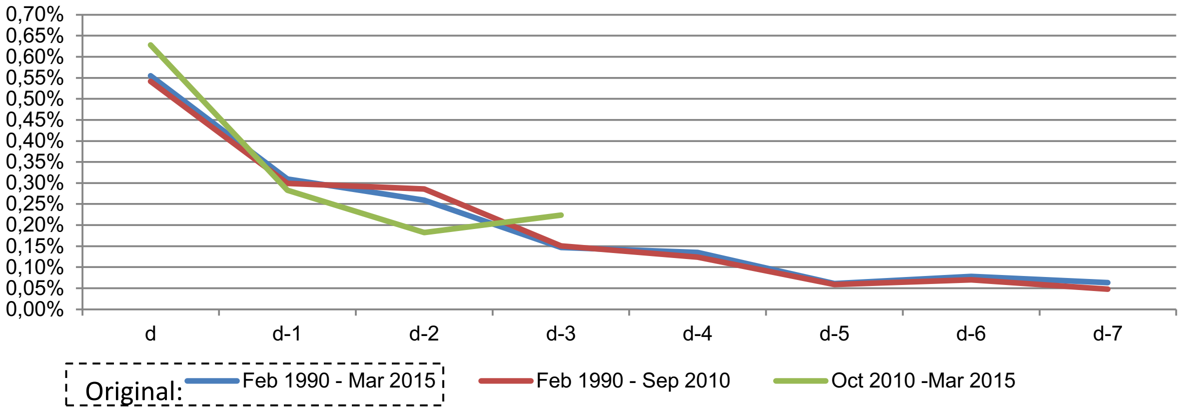
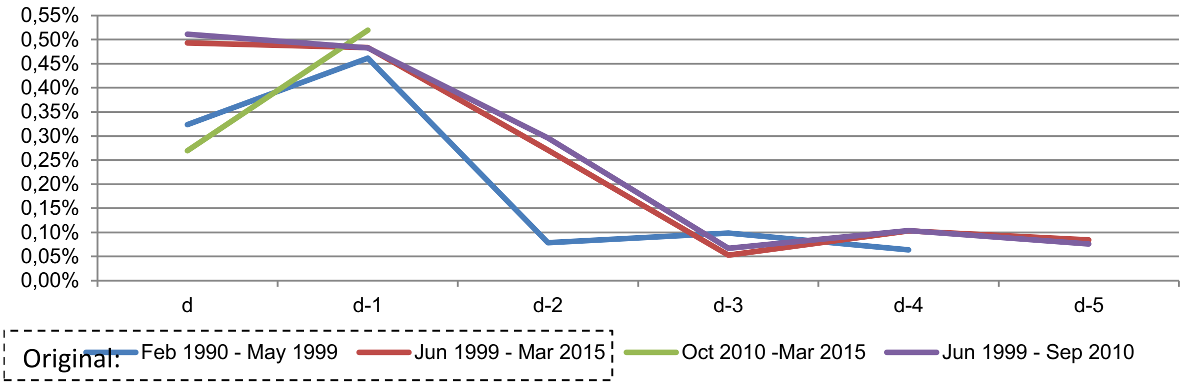


Figure 6: New cooling response function.



Once the breakpoints of the response function have been set, it has been also reviewed the possibility of change in the temperature threshold. To do that, the model has been estimated iterative changing the threshold in one degree. The results of the adjustments process is shown in figure 7 were the minimum error is set for the combination of 19ºC in heating zone and 23ºC in cooling zone, what it means that the threshold of the heating zone would be reduced in 1ºC.

Figure 7; Temperature threshold: Sum of squared residuals.

		Heating (ºC)					
		21	20	19	18	17	16
Cooling (ºC)	22	1,9338	1,9334	1,9318	1,9324	1,9340	1,9340
	23	1,9222	1,9222	1,9209	1,9218	1,9235	1,9235
	24	1,9355	1,9349	1,9332	1,9338	1,9354	1,9354
	25	1,9313	1,9306	1,9290	1,9296	1,9313	1,9313
	26	1,9311	1,9304	1,9287	1,9293	1,9310	1,9310
	27	1,9309	1,9302	1,9285	1,9291	1,9308	1,9308

Due to the thresholds have changed, it is necessary to review if the lags of the response functions estimated above continue being in force. To check this point, the models estimated during the process were re-estimated again, without detecting any change in the conclusions presented earlier. As a result of this, and regarding the response function to temperatures, the final adjustment of the model is the following:

Heating	1990-2010 Value		Est. T		2010 -2015 Value	Est. T
d	0,0054		28,88		0,0065	8,27
d-1	0,0030		15,91		0,0028	3,60
d-2	0,0029		14,89		0,0021	2,68
d-3	0,0015		7,79		0,0025	3,14
d-4	0,0012		6,47		-	-
d-5	0,0006		3,08		-	-
d-6	0,0007		3,72		-	-
d-7	0,0005		2,57		-	-
Cooling	1990-1999 Value	Est. T	Hasta 2010 Value	Est. T	2010 -2015 Value	Est. T
d	0,0034	9,27	0,0051	16,85	0,0027	2,90
d-1	0,0045	11,98	0,0048	15,91	0,0051	5,49
d-2	0,0007	1,80	0,0030	9,51	-	-
d-3	0,0010	2,50	0,0007	2,14	-	-
d-4	0,0005	1,39	0,0010	3,41	-	-
d-5	0,0051	16,85	0,0008	2,50	-	-
R^2 Adj			98,1096%			
$\Sigma error^2$			1,9209			
D-W			2,01			

5CONCLUSSIONS

The economic recession has obviously got a deep impact on the Spanish economy and as a result of it the electricity demand has been strongly reduced. Although a part of this lower demand is consequence of the reduction of the numbers of consumers (households and companies), part is also due to changes in the response function of the demand to temperature variations because the lower consumers income.

To estimate when changes have been occurred in the response function and the size of them, different statistical approaches have been used being the main conclusions of the analysis the following:

- The economic recession has produced a change in the response functions of heating and cooling.
- The new adjustment improves the explanatory level of the model, reducing the error in a 24.1% on regards of the present version of the model without changes.
- The changes in the response functions starts at the beginning of the winter 2010-2011.

Heating zone

- The sensitivity per degree day is 11.6% lower on regards on the previous period.
- The response function curve has been pointed, with more significance of the temperature of the present day.
- The influence of the previous days has been reduced. Now only affects the three previous days while in the previous version was 7 days before.
- The threshold sensitivity has been reduced from 20ºC to 19ºC

Cooling zone

- The sensitivity per degree day is 48.8% lower on regards on the period 1999-2010.
- The temperature of the previous day has more importance to explain the consumption of the present day than the temperature of the day. This situation is similar to the response function of the period 1990-1999.
- The influence of the previous days has been reduced. Now only the day before is affected while in the previous version was 5 days before.

Annex 1: Main statistics of estimation process. Adjustment period feb-1990-mar-2015

Winter	2009-2010		2009-2010		2010-2011		2010-2011		2011-2012		2011-2012		Original adjustment	
Summer	No change		2010		No change		2010		No change		2010			
	Valor	Est. T	Valor	Est. T	Valor	Est. T	Valor	Est. T	Valor	Est. T	Valor	Est. T	Valor	Est. T
Heating														
Before change														
d	0,0054	27,90	0,0054	27,88	0,0054	28,95	0,0054	28,93	0,0055	29,98	0,0055	29,97	0,0056	30,70
d-1	0,0031	15,95	0,0031	15,95	0,0030	15,92	0,0030	15,90	0,0030	16,61	0,0030	16,59	0,0031	17,01
d-2	0,0028	14,23	0,0028	14,22	0,0029	14,91	0,0029	14,89	0,0028	14,96	0,0028	14,96	0,0026	14,00
d-3	0,0016	7,92	0,0016	7,92	0,0015	7,79	0,0015	7,79	0,0016	8,29	0,0016	8,28	0,0015	7,88
d-4	0,0013	6,44	0,0013	6,45	0,0012	6,46	0,0012	6,46	0,0012	6,59	0,0012	6,58	0,0013	7,25
d-5	0,0006	3,13	0,0006	3,13	0,0006	3,07	0,0006	3,07	0,0005	2,75	0,0005	2,76	0,0006	3,29
d-6	0,0006	3,34	0,0006	3,34	0,0007	3,71	0,0007	3,72	0,0007	3,89	0,0007	3,88	0,0008	4,31
d-7	0,0005	2,59	0,0005	2,59	0,0005	2,57	0,0005	2,56	0,0005	2,66	0,0005	2,66	0,0006	3,48
After change														
d	0,0058	10,77	0,0058	10,80	0,0065	8,51	0,0063	8,32	0,0048	3,04	0,0048	3,03	-	-
d-1	0,0020	3,79	0,0020	3,75	0,0031	4,08	0,0028	3,76	*No Signif*		*No Signif*		-	-
d-2	0,0025	4,65	0,0025	4,65	0,0020	2,63	0,0018	2,42	*No Signif*		*No Signif*		-	-
d-3	0,0013	2,38	0,0013	2,37	0,0027	3,44	0,0022	2,95	*No Signif*		*No Signif*		-	-
d-4	*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		-	-
d-5	*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		-	-
d-6	*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		-	-
d-7	*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		*No Signif*		-	-
Cooling														
Before change														
d	0,0049	16,93	0,0051	16,82	0,0049	16,98	0,0051	16,85	0,0049	16,97	0,0051	16,85	0,0049	17,33
d-1	0,0049	16,90	0,0048	15,87	0,0049	16,92	0,0048	15,91	0,0049	16,94	0,0048	15,91	0,0048	16,94
d-2	0,0027	9,17	0,0030	9,50	0,0027	9,20	0,0030	9,51	0,0027	9,20	0,0030	9,52	0,0027	9,23
d-3	0,0006	1,93	0,0007	2,14	0,0006	1,94	0,0007	2,14	0,0006	1,95	0,0007	2,14	0,0005	1,80
d-4	0,0011	3,88	0,0010	3,39	0,0011	3,92	0,0010	3,41	0,0011	3,91	0,0010	3,42	0,0010	3,61
d-5	0,0008	2,82	0,0008	2,49	0,0008	2,85	0,0008	2,50	0,0008	2,85	0,0008	2,51	0,0008	2,95
After change														
d	-	-	0,0027	2,89	-	-	0,0027	2,89	-	-	0,00273	2,92	-	-
d-1	-	-	0,00521	5,55	-	-	0,0052	5,54	-	-	0,00519	5,54	-	-
d-2	-	-	*No Signif*		-	-	*No Signif*		-	-	*No Signif*		-	-
d-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
d-5	-	-	-	-	-	-	-	-	-	-	-	-	-	-
R^2 Adj.	98,1064%		98,1052%		98,1108%		98,1088%		98,1108%		98,1094%		97,7278%	
$\Sigma error^2$	1,9252		1,9259		1,9197		1,9222		1,9215		1,9224		2,5306	
D-W	2,01		2,01		2,01		2,01		2,01		2,01		2,05	

Demand Response: a survey on Challenges and Opportunities

Francesco Gianelloni[1], Lorrane Câmara[2], Andre Leite[3], João Felippe Cury Marinho Mathias[4]

[1] UFRJ - GESEL, Av. Pasteur 250, Rio de Janeiro, Brazil, francesco.zubiria@ppge.ie.ufrj.br
[2] UFRJ - GESEL, Av. Pasteur 250, Rio de Janeiro, Brazil, lorrane.camara@pped.ie.ufrj.br
[3] UFSC, Av. R. Eng. Agronômico Andrei Cristian Ferreira, Florianópolis, Brazil, andre.ls.leite@gmail.com
[4] UFRJ - GESEL, Av. Pasteur 250, Rio de Janeiro, Brazil, mathias@ie.ufrj.br

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ABSTRACT

Higher efficiency and reliability of the electric system are important goals to be achieved. The increasing growth and importance of intermittent renewable energy sources and its massive incorporation into the electricity grid, given the efforts to diversify the energy mix and reduce the carbon emissions, bring new challenges to the sector, such as the need of higher levels of flexibility. In this context, demand-side flexibility measures come to light as a way of improving system reliability and, at the same time, defer the need for investments in the expansion of distribution and transmission grids, reducing the demand for additional generation capacity and allowing the shave of peak demand, resulting in a reduction of electricity costs. Among these measures, demand response figures as one of great importance. It is based on electricity consumers' capability to respond to price signals, increasing the consumers' role in ensuring system security in a cost effective way.

The objective of this article is to examine some of the main challenges and opportunities for enabling demand response programs, taking some lessons from the international experience. An additional effort is to focus on Brazilian case. The methodology consists of bibliographic and documental review, with the analysis of challenges and opportunities, followed by an investigation of demand response programs in Brazil. This paper was developed under the framework of a project supported by the ANEEL's R&D Program. It was found that technological requirements of demand response can be a great obstacle, as observed in some of the European countries cost-benefit analysis and in the Brazilian case. The Brazilian experience is by all means only incipient and takes advantage of a small part of the full demand response potential, but even in this condition, shows some positive results in efficiency.

KEYWORDS: Demand Side Management; Demand Response; Smart Grids; Demand Flexibility; Dynamic Pricing

1. INTRODUCTION

In almost every market, demand and supply conditions determine the price, which, as a result, allows equalization of quantities in both sides. Consumers demand and producers supply certain quantities according to the current price. A perturbation in demand or supply conditions is communicated to the market through changes in quantities and, in the case of inexistent price rigidities, results in a new price level which *clears* the market given the supply and demand conditions. In short, it allows demand and supply equalization. This mechanism, in competitive markets, is very efficient from resources allocation point of view (Varian, 1996). However, in electricity markets, tariffs usually (the price) have a certain degree of rigidity; in other words, their adjustment for a new level is delayed in a certain amount of time, which that depends on certain institutional, technological and market niche conditions. Electricity tariffs usually reflect the variable costs incurred in the last period before the adjustment. So, if during the last period through which the price was fixed, the costs raised (in face of a higher demand, or higher fuel prices for example) in comparison to the previous period, the current price will reflect this raise in costs and elevate in relation to the previous.

Notwithstanding, the demand and supply of electricity must always be the same in order to ensure that all consumers receive the demanded electricity, task that is assigned by the system operator. Supply conditions (costs and availability) of electricity are subject to variability, since some of the generation technologies depend on stochastic and intermittent natural conditions. In a scenario of decarbonization and serious insertion of renewable energy sources in the power mix, this variability of supply becomes even more significant (Ambec and Crampes, 2015). From the consumers point of view, their demand have seasonal and hourly variations, since it also depends on natural conditions to which they react (temperatures changes during the year) or conditions inherently related to the intra-day schedules (like business hours).

The main problem with the price rigidity is its incapability of communicating these changes during a period of price rigidity that only operates a unique tariff. This results in a demand that is “blind” to these conditions, and acts inflexible, precluding, for instance, consumers with flexible demand capacity to consume during lower prices periods, which are characterized by good supply conditions and a lower demand. Another inherent consequence of such a rigid tariff system is the turmoil caused by these characteristics during peak demand periods, when the supply’s reliability and safety are jeopardized in face of simultaneous adverse natural conditions. A financial compensation (lower than the costs of system blackout) from the energy retailers to those willing to reduce or even cut their consumption to zero in those critical periods could be a reasonable and efficient way of increasing the electric sector supply reliability. This last is classified as an ancillary service.

Both of the above glimpsed alternatives, the more dynamic tariff in opposition to the very rigid tariff, and the possibility of an instantaneous demand response (financially compensated) in face of adverse supply conditions (conditions pre-determined), are part of what is known in the economic literature as Demand Response (DR), since they result in responses from the demand side. In FERC’s definition: “Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.” (FERC *apud* MIT, 2011, p.147)

The objective of this article is to examine some of the mains challenges and opportunities for enabling demand response programs, taking some lessons from the international experience. An additional effort is to focus on Brazilian case, whose electric system comes from a very different background but is facing the same challenges of an ever increasing role of intermittent and stochastic renewable sources in the electricity generation matrix, just like the European and North American countries.

2. OPPORTUNITIES

One of the greatest motivations for enabling demand response mechanisms relies on its capability of reducing costs, through more efficient consumption choices. More dynamic tariffs and lower or incentivized voluntary demand curtailment have as a consequence what came to be known as *peak shaving*. Peak shaving is the result of a reduced demand during usually higher demand periods (peak periods). Since consumers charged with dynamic tariffs are aware of the higher costs of these peak demand periods through higher tariffs, they will tend to shift their load to other ones, with lower tariffs. If this temporal shift in load does not alter the overall period electricity consumption, then the result is called *load shifting*. If it does alter, in a way that consumption in other periods do not compensate the consume reduction during peak demand periods, then the result is called *load shed*. Electricity generation marginal costs tend to be crescent, since dispatch ordering criteria is customarily based on merit (lower costs first), which means that the total cost is a convex function of the demand. So if the total electricity consumption is the same for two different periods, the period with less variability (or fewer/lower peaks) will be the less expensive[1]. Considering that load shifting is in itself a consequence of a better management aiming costs reduction and that load shedding will only happen voluntarily (financially inactivated, with economic based incentives), it is easy to conclude that there must be a cost reduction.

With an ever increasing insertion of renewable energy in a large number of countries power mix, intermittency and stochastic behavior from part of the supply side can jeopardize the electrical system stability or even its supplying capability for a given time (Ambec and Crampes, 2015). Wind plants, for example, are subject to very high generating oscillations, exerting high stress over the supply and demand balance, as illustrated by Fig. 1:

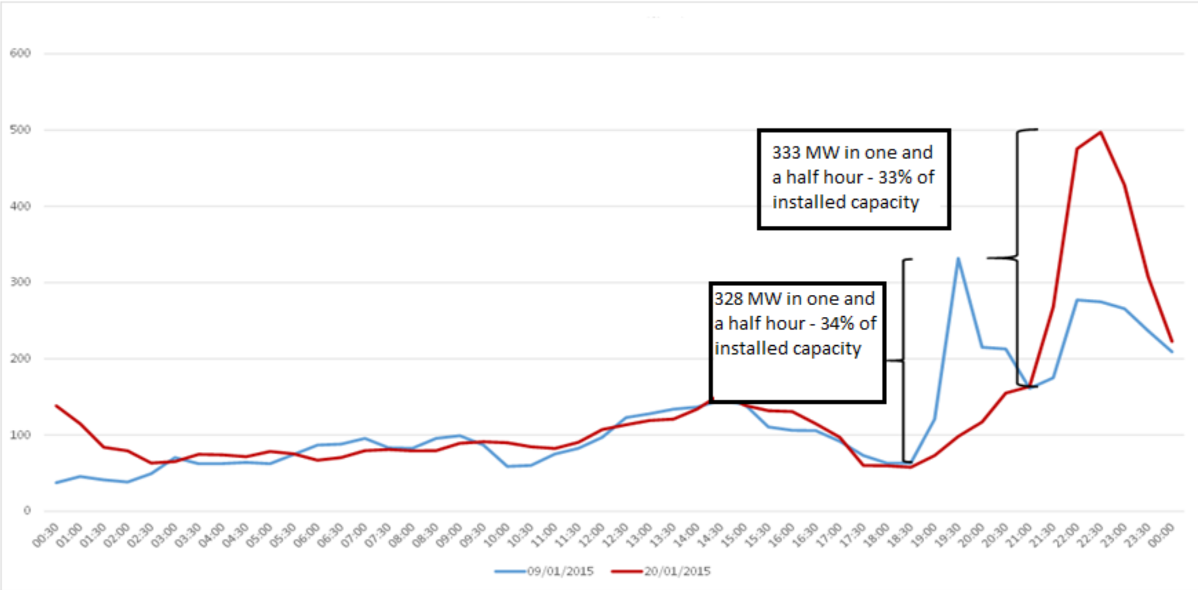

Figure 1: A Brazilian wind plant intermittent profile. Days: 09/01/2015 and 20/01/2015. Source: ONS – Brazil's system operator

Another motivation, according to Sheikhi Fini et al (2013), quoted by Poudineh and Jamasb (2013), can be identified in the opportunity of postponement in grids investments. Since peak shaving results in a more stable demand, grids can operate with less idle capacity and the current grid installations might be able to work without the need for upgrades and reinforcements for the next few years. Fig. 2 illustrates the case with a British example:

Figure 2: Estimated costs of grid reinforcements in Great Britain, with and without (business as usual) demand response, for different heat pumps and electric vehicles penetration levels. Source: G Strbac et al (2010), Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks

[1] By the Fundamental Theorem of Calculus $F'(x) = f(x)$. Since $F'$is increasing, F is convex. If $w = x + x$ and F is convex, then $\int_0^x f(x) < \int_x^w f(x)$. So we conclude that $\int_0^w f(x) = \int_0^x f(x) + \int_x^w f(x) > \int_0^x f(x) + \int_0^x f(x) = 2\int_0^x f(x)$. In short: $F(w) > 2F(x)$. Either x and w can be considered as the consumption of a period, as long as equal periods have equal consumptions, with F representing the total cost function in a given period and f the marginal cost function. This result can be extended analogously for a larger number of sub-periods.

	Without DR programs	With DR programs
Penetration Level	Total Investment (£bn)	Total Investment (£bn)
10%	5.1	2.2
25%	13.0	4.7
50%	25.5	11.1
75%	33.8	18.7
100%	38.8	22.2

Fig. 2 shows different investment scenarios for grids reinforcement in Great Britain, taking in consideration possible heat pumps and electric cars penetration levels, both considered great drivers for increased electricity consumption. It is possible to observe that as the penetration level raises, demand response's absolute contribution increases, but its relative contribution, taken as a proportion of avoided investments, falls.

The same reasoning can be used to explain the postponing over generation capacity investments permitted by a more stable demand, cutting off the necessity of operating with a large number of plants that remains most of the time on an idle stance, acting in emergency. In addition to that, a capacity market with DR participation, where DR can act as a "generating investment substitute", offering services that have the same effect on a demand-supply balance, makes even clearer this opportunity.

It is important to note that in order for achieving all demand response potential, securing all the opportunities, not only prices must update more rapidly, in order to incentivize demand response, but ancillary and capacity markets must also act together. There are technical and regulatory requirements that must be attended for the purpose of enjoying all DR benefits. The section bellow addresses these requirements and challenges.

3. CHALLENGES

3.1. Technological Challenges

It is impossible to achieve Demand Response without certain technological requirements. The most important of them is the smart meter. Smart meters allow more dynamical tariffs, and in some cases, real time tariffs, with hourly updates. Smart meters can be seen as Demand Response enablers (Cambridge Economic Policy Associates Ltd, Tpa Solutions & Imperial College London, 2014). They also grant fast response in electricity demand, allowing even automation of electrical demand reduction or curtailment, when certain conditions are met. These actions are even more efficient when smart meters are combined with smart electronics, like smart air conditioners or heaters that react to price signals, reducing demand intensity. Aside from smart meters, there is a need for other investments in equipment for data retention, communication in general, and reporting infrastructure to work in assistance with the meters which are indispensable (Hurley et al, 2013). Professionals must be hired in order to keep an informational structure, which also results in increased costs.

The main challenge is not the existence of the technology itself, but the costs of its implementation. Smart meters costs are very significant and can result in increased electricity tariffs, since the investment has to be amortized. Given this, a cost-benefit analysis has to be made, in order to decide if a smart meters rollout is an economical based decision and how much of the rollout must be executed (a partial rollout might be the best decision).

Fig. 3 shows the cost-benefit analysis for a large number of countries in European Union, in the case of a rollout reaching at least 80% of the homes in the country and most of the main big consumers:

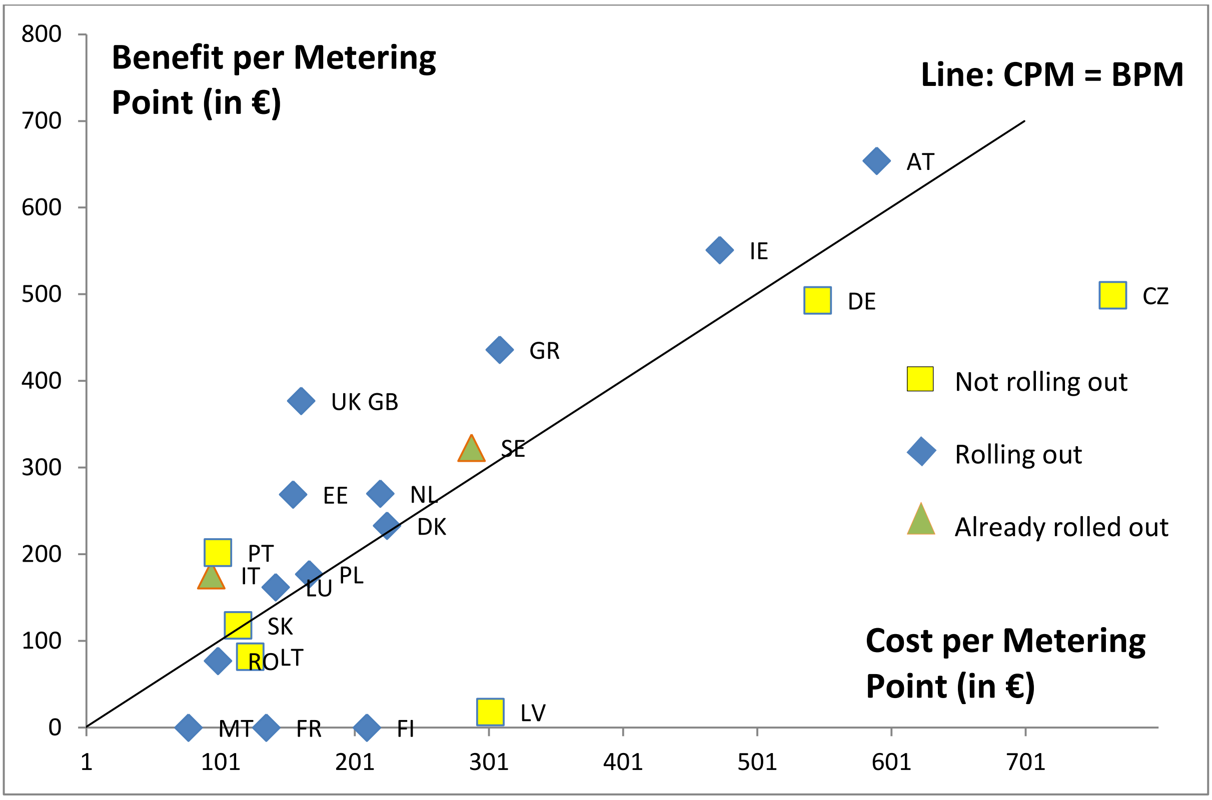

Figure 3: Summary of costs against benefits in countries in the European Union. Source: EC SWD (2014) 189 Cost-benefit analyses & state of play of smart metering deployment in the EU-27

There is no data for Malta, France and Finland benefits estimation, but their smart meters rollouts are in execution. The benefits include faster detection and restoration of service, contraction of energy loses and theft, DR gains, such as power saving and peak load shaving, considering also postponed investments in grid reinforcement. It is possible to observe that for most countries, the estimated benefits overcome the estimated costs. Considering that technologies costs tend to decrease over time and that the participation of renewable energy is growing in most European countries power mix, as a result of an effort of decarbonization lead by the *Renewables Directives*, we expect that future cost-benefit analysis will recommend smart meters rollouts, since the benefits will grow with a more intermittent electricity generating matrix. In Brazil, the same reasons apply, so it must follow a similar trend.

3.2. Regulatory Challenges

A large number of challenges from the regulation side can be pointed out. First of all, there are regulatory practices that may difficult the implementation of smart meters. It is possible that excessively high or unclear technical standards prevent smart meter rollouts. A good example of technical standards barriers is the Brazilian case, which will be analyzed subsequently. Even when it is legal, lack of incentives to its implementation can become a barrier if a cost-benefit analysis results in a small margin. Another difficulty can arise from a regulatory framework that does not provide clear incentives and/or a proper remuneration for the services provided by consumers engaged in DR programs. An even stronger regulatory barrier is the possible restriction on DR participation, by restricting aggregators, with a large number of small and technologically restricted consumers, from participate and engage, or by restricting types of services (Hurley et al, 2013).

As mentioned before, regulation is responsible for the allowance or not, of ancillary services and capacity markets that have DR as a tool, through adequate institutions and laws. So proper regulation, in order to permit DR from a variety of consumers in capacity markets and ancillary services is a must, in countries that expect to take serious advantages of Demand Response programs.

4. BRAZILIAN EXPERIENCE

Brazilian power sector consists of a hydrothermal system based on the intensive exploration of the hydro potential, complemented by thermal generation from different sources (Castro et al. 2010). Current installed capacity is predominantly compounded by hydro power plants, representing 67.7% of the total capacity, which corresponds to approximately 90 GW (BRASIL, 2015). An important characteristic of Brazilian power sector is the presence of huge water reservoirs, which have played the role of regularizing hydro based energy supply along the year, reducing the risk and uncertainty associated to affluences seasonality. These reservoirs have had, for a long time, a multi-annual profile. However, in the last few years this scenario has being changing. In face of a fast demand growth, associated to restrictions to the construction of new hydro plants with big water storage capacity (social and environmental restrictions associated to topographic features of remaining capacity), the reservoirs are losing their regularization capacity. The already contracted hydro capacity expansion until 2019 totalize almost 19 GW, from which 99% consists on water flow power plants and the remaining 1% is represented by a single plant with water reservoir, which has 135 MW of installed capacity (BRASIL, 2015).

Furthermore, a strong increase of renewable energy resources, like wind and solar, is projected to the next few years. Wind power capacity, for example, will reach 8,5 GW by the end of 2015 (BRASIL, 2015). Concomitantly, mini and microgeneration, mostly from photovoltaic panels, will become a very relevant source in the coming years.

As a consequence of this scenario of increasing participation of hydro power plants without reservoirs, as well as wind and photovoltaic plants, energy sources characterized by the stochastic and intermittent profile, Brazilian electric system faces higher risks, uncertainty, variability and unpredictability levels related to energy supply. These factors impose to the System Operator a challenge to ensure electricity supply reliability, real time equilibrium between supply and demand, and, even more, to ensure the supply of peak demand.

This scenario results in a higher demand for cost efficient flexibility sources, and, although Brazilian experience with demand response programs is still incipient, as will be shown below, demand response represents an alternative of system flexibility, which tends to come into light in a near future.

4.1. Hourly Fee

In 1988, Brazil initiated the application of demand reaction programs based on time of use tariffs (TOU), with the creation of time-of-day/seasonal (horoseasonal) tariffs. This tariff structure encompass the hourly signaling (peak time tariff and out of peak tariff) and the seasonal signaling (wet and dry periods), and it is applied to medium and high tensions consumers. The hourly fee consists on a binomial tariff, with a price component applicable to electricity consumption (KWh) and another one to power demand (KW). (ANEEL, 2010)

Even though the intermittency and stochastic factors were not the addressed problems in 1988, since they reflect a contemporary conjectural problem, the hourly fee represented a first step in the way of a more dynamic tariff, allowing reduction of time lags in cost transmission through tariffs.

In the tariff review cycle of 2011, however, it was extinguished the seasonal signal of the tariff structure, given that was outdated and couldn't well reflect the costs and power sector conditions any more. At the same time, ANEEL creates a new tariff modality called White Tariff, applicable to low tension consumer and inspired on the Hourly Fee.

Studies prove the effective industrial consumer's response to the tariffs with hourly signalizations, as can be seen in the Fig. 4:

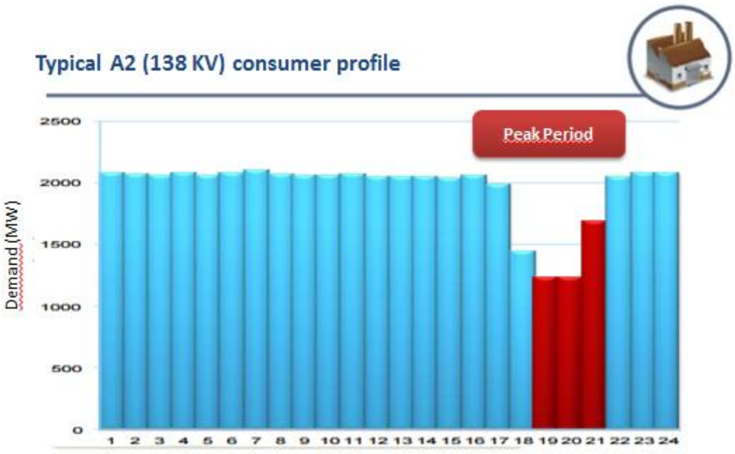

Figure 4: A typical A2 (138KV) consumer profile. Source: ANEEL

The graphic above represents the reduced consumption of a typical high tension consumer, during peak time. Since this is a typical consumer, a large number of high tension consumers behave this way, resulting in a load shifting movement, reducing overall generation costs and reducing operational risks during the peak period.

4.2. White Tariff

The White Tariff is a kind of Time of Use tariff, designed to be applied to the lower tension consumers, including residential, commercial and rural consumers, with voltage electricity supplying lower than 2.300 volts (Santos et al., 2014). The adherence is facultative, and it communicates consumers about the electric energy price according to the day and hour of consumption. The White Tariff is a monomial tariff (R$/MWh), as it is solely based on the amount of energy consumed. It is composed by three "tariff ranks": peak, which consists of three straight hours, usually between 18h and 21h; intermediate, which consists of the immediate previous hour and the subsequent hour of peak time; and out of peak, which consists of the remaining hours (ANEEL, 2015). According to the National Electric Power Agency (ANEEL), White Tariff was created with the main purpose of offering to lower tension consumers a higher variety of tariff modalities, in order to obtain, by their own choice, positive effects to the system through temporal load shifting. According to ANEEL (2010), hourly fees aim to reduce the gap between price and marginal cost of marginal consume meeting and, thus, induce demand shift from periods when the grid is crowded to others when the grid works with idle capacity. Meanwhile, an issue that comes into light is how much the residential demand will vary in response to electricity price variations, in other words, what is the price elasticity of residential demand. This parameter is crucial to the effectiveness of White Tariff.

The White Tariff can be seen as a first reaction to the forecasted and lately established new scenario, with loss of regulation capacity through reservoirs management and a more significant role of renewable, intermittent and stochastic, sources of electricity.

The Normative Resolution 502/2012 by ANEEL stablished 2014 March as the deadline for smart meters installation for those that adhered to the White Tariff, as distribution companies' responsibility. However, in 2014 February, ANEEL postponed the White Tariff execution date in face of the unavailability of smart meters certificated by INMETRO, according to the technical criteria defined by NR 502, on the market (Santos et al., 2014). As mentioned earlier in this article, one of the main barriers for white tariff (a more dynamic tariff) implementation is the need for smart meters installation. By now, the deadline to White tariff implementation is still opened. As observed in the "challenges" section, technical requirements can become a remarkable obstacle, which in the Brazilian case, until now, has acted as an impediment. As far as we know, no cost-benefit analysis of smart meters was carried in Brazil, but as facts have shown, it is to be expected that, if it was carried, a positive cost-benefit analysis would be an improbable scenario.

4.3. Tariff Flags System

The most recent Brazilian experience with demand response is the Tariff Flags System, and it was created in order to mitigate the risks associated do the hydro crisis Brazil is facing. It is also known that Brazilian power sector is strongly based on hydro power plants, and counts on a Centralized System Operator that determines the dispatch according to an optimization computer model called NEWAVE. One of the main outputs of this model is the CMO (Marginal Operation Cost), which basically represents the opportunity cost of water, in terms of other available sources. The CMO reflects, mainly, the current and forecasted hydrology conditions. So, in situations of unfavorable hydrology, the CMO reaches high levels. Based on the CMO the ONS (National System Operator) determines the dispatch of the system plants, according to the merit order. This marginal cost also has a great impact on the short term electricity market, through its influence on the PLD (Settlement Prices for the Differences), that is the short term price, and also reflects hydrology conditions, tending to be in the minimum when the system faces good hydrology and can reach the maximum in situations of unfavorable hydrology (Castro et al., 2014). Another important characteristic of Brazilian system is associated to the energy market, which is not a day ahead market, like in Europe, but a long term contracts market, in which consumers need to contract 100% of their demand. The dispatch, otherwise, has no relation with the energy contracted, what results in a high volume of differences to be liquidated by the PLD on a monthly basis (Castro e Brandão, 2015). This decoupling between contracts and dispatch represents a high financial risk to the agents, who are constantly exposed to an energy price with high volatility. It is also important to highlight that the costs incurred by distributors in energy purchasing are passed on to the consumer with a big delay, what lead the system to an even more difficult situation.

With Tariff Flags System there is a better cost signalization, giving the consumer the chance to adapt his demand, as well as inducing a demand reduction, reliving the system. The Tariff Flags aim to signalize consumers about the real power generation conditions, which is dependent on hydrological conditions and the need to dispatch thermal plants. Their purpose is to reduce the adjusting delay between electricity costs and the price charged from the consumers. Given this, it is expected that the consumers will respond to the supply costs variations. In other words, it acts as a DR program, in the definition sense, but its authenticity is questioned, since it is a compulsory system.

This system can be seen as a strong reaction to a very adverse conjectural problem, originated with a very unfavorable hydric condition, resulting in the intense use of thermal energy plants that were not designed to work for such a long period and had as a consequence a calamitous (and very exceptional) rise in electricity costs. Since hydric conditions can change, and these changes are difficult to forecast, keeping the tariffs elevated with the possibility of reduction after every month results in flexibility gain.

The Tariff Flags System is applied by all distribution companies connected to the National Integrated System – SIN, so it is compulsory to all captive final consumers. The green flag is turned on during the months in which the variable cost per unit (VCU) from the last dispatched power plant is below R$ 200/MWh. In this case, the default tariff is charged. The yellow flag, otherwise, is powered during the months when the VCU is equal or above R$ 200/MWh and below the maximum PLD (Differential Liquidity Price), currently at R$ 388,48/MWh. The default tariff raises R$ 0,025/kWh. Finally, the red flag is turned on during the months when the VCU is equal or above the maximum PLD. The default tariff raises R$ 0,045/kWh. It is by all means a compulsory method, applied to all captive consumers. It is important to highlight that, since the implementation of this system, red flag is triggered (ANEEL, 2015).

5. CONCLUSIONS

Demand response programs can be considered as new and recent alternatives, allowed by technological advances, to deal with a more complex, diversified and intermittent electricity generation matrix, which are becoming a trend worldwide, due to a decarbonization effort, aiming to reduce the global warming progress. The opportunities and motivations that propel research, pilot programs and innovative regulation are: the overall cost reduction, achievable through peak shaving, either by load shed or load shifting and also deferment of grid and generation investments. Gains in reliability, with the participation of DR in ancillary services and capacity markets can be added to these. However, there are challenges to be faced, such as regulation and technical requirements currently acting as barriers to DR implementation. Technical requirements can be achieved if cost-benefits analysis shows good results, as it has already shown in a large number of European countries. Innovations on the regulatory side are mandatory in order to achieve full DR programs advantages.

The short analysis of the Brazilian experience on demand side flexibility programs lead us to conclude that the evolution of the electricity generating park in Brazil will require greater flexibility of the system, and demand side policy must be considered as an important alternative. However, the Brazilian Demand Response experiences are still incipient. The Tariff Flags system, for example, is not a genuine demand response program. Demand response in Brazil has been focused on great consumers. The White Tariff is unable to be implemented due to an inexistent smart meter rollout, reflecting the strength of such obstacle in the way of demand response enabling. Finally, there are uncertainties about the price-elasticity of the demand from residential consumers of electricity, which proposes another challenge to a full smart meter rollout.

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Mapping fuel poverty in Portugal

Sofia Simoes[1*], Vera Gregório[1], Júlia Seixas[1]

[1] CENSE – Centre for Environmental and Sustainability Research, Faculdade de Ciências e Tecnologia, Universidade NOVA de Lisboa, 2829–516 Caparica, Portugal, sgcs@fct.unl.pt, v.gregorio@campus.fct.unl.pt, mjs@fct.unl.pt
** Corresponding author*

ABSTRACT

We defined a methodology to assess the potential fuel poverty of residential dwellings supported by statistical information easily available from the Statistics Portugal at level (formerly NUTS 5). In this paper fuel poverty refers to persons living in households that they cannot afford to heat and/or cool adequately, with particular emphasis in persons with 65 years old or more. For different building typologies of households, we combined data on income, level of education, unemployment rate, and number of inhabitants above 65 years old, with both the space heating and cooling gap estimated for each household typology. We estimated the space heating and cooling gap as the difference between the heating and cooling final energy needs per household for the thermal comfort as stated in the regulation and the final energy consumption that took place in 2013 according to national energy balances. The approach resulted in an indicator of the share of potential fuel poor households in the total households of each LAU 2 region.
We have implemented this methodology for 29 municipalities in Portugal participating in the Project ClimAdaPT.Local. For the LAU 2 units (*civil parishes*) of those municipalities, in average, 22% of the inhabitants are potentially fuel poor regarding the satisfaction of their dwellings' space heating needs and 29% regarding space cooling needs. There is a large variation across the country in these indicators. The maximum share of potentially fuel poor inhabitants for heating is 75% and the minimum is 8%, located in the Rio de Onor civil parish in Bragança and in Real in Braga, respectively. Regarding cooling, the share varies between 10-75%, in Frossos in Braga and Rio de Onor, respectively. Although, in general, the LAU 2 units potentially most fuel poor regarding heating are also fuel poor regarding cooling, they are not always the same. In other words, depending if looking at heating or cooling needs, some LAU 2 units are highlighted as hotspots for fuel poverty and others not. We conclude that for southern European countries, fuel poverty must also take into account the energy needs for space cooling. For the case of Portugal, it is urgent to collect more detailed information on energy consumption profiles across the country for a better identification of fuel poverty hotspots.

KEYWORDS: Fuel poverty, residential buildings, thermal comfort, heating and cooling

1 INTRODUCTION

There are several definitions of fuel poverty (also known as energy poverty by some authors, including the European Commission), but more commonly the term is used to refer to persons living in households that they cannot afford to heat adequately (Boardman, 1991; Liddell &

Morris, 2010; Pye et al., 2015; Thomson, 2013). Frequently, other energy uses are also included in the concept (Boardman, 1991; Pye et al., 2015), although most authors focus on heating. Following the varied definitions of the concept, there are also varied approaches to measure it across the European Union (EU) (Liddell & Morris, 2010; Thomson, 2013), from considering as fuel poor the households that use 10% more than of their available income to heat their homes up to World Health's Organization Standards (WHO) in the UK (Sefton & Chesshire, 2005) and Ireland (Thomson & Snell, 2013), to simply surveying the number of days that the dwellings have gone excessively cold (or warm), had delays in paying their energy bills, or were disconnected due to debt (EUROSTAT, 2014; Romero, Linares, Otero, Labandeira, & Alonso, 2014).

Assessing fuel poverty is an area of work mostly developed in the UK (Thomson & Snell, 2013; Thomson, 2013; Walker, McKenzie, Liddell, & Morris, 2014), where the concept was brought to attention by the seminal work of Brenda Boardman (Boardman, 1991). Since then, studies have been developed for other countries such as for Austria (Brunner, Spitzer, & Christanell, 2012), Bulgaria (Bouzarovski, Petrova, & Sarlamanov, 2012), France (Legendre & Ricci, 2015), Italy (Fabbri, 2015), and Spain (Romero et al., 2014; Scarpellini, Rivera-Torres, Suárez-Perales, & Aranda-Usón, 2015). Some overviews have been made for the whole of EU, as (Healy, 2004) that reviewed housing and socio-economic conditions for fourteen countries using Ireland as a benchmark, or the work of (Thomson & Snell, 2013) that used the EU Survey on Income and Living Conditions (EU-SILC) data to compare 25 EU member states looking at housing conditions, energy inefficiency and energy affordability. According to these studies Portugal, Greece, Italy and Spain were the most fuel poor countries in the EU (Healy, 2004) and, according to the EU-SILC data, Portugal had in 2013 roughly 20-29% of households that were fuel poor. (Thomson & Snell, 2013) reported similar findings more recently although Southern European countries have been joined by Easter European countries as Bulgaria and Romania. In order to successfully deal with fuel poverty, authors seem to agree that the key defining features of fuel poverty have to be addressed: location, housing quality and income (Dubois, 2012; Thomson & Snell, 2013).

In this paper, we present a new approach to assess potential fuel poor inhabitants considering such features, focused on space heating and cooling for households. We apply the approach to assess where the fuel poor households are located within 29 municipalities in Portugal under the *ClimAdaPT.Local* project. *ClimAdaPT.Local* is an ongoing project leveraging the capacity building at municipalities to develop comprehensive Municipal Strategies for Adapting to Climate Change (MSACC). The paper is organized as follows: section 2 describes the methodology proposed, the results are presented in section 3, and section 4 concludes and highlights some of the needs for improvement.

2 METHODOLOGY

The approach adopted in this paper to assess potential fuel poor follows the framework of (Schneiderbauer et al., 2014) to determine whether and to what extent a system is vulnerable to climate change and includes four key components: 1) *exposure* – variables directly linked to climate parameters (e.g. temperature, precipitation), 2) *sensitivity* – the degree a system is affected by exposure (e.g. physical attributes of the system, as buildings characteristics), 3) *potential impact* – measured by the combination between exposure and sensitivity (e.g. the potential impact on thermal comfort), 4) *adaptive capacity* – the ability of a system to adjust to climate change (Adger, 2006), mostly related with societal environment (e.g. demography, literacy, socio-economic conditions). This approach was initially developed by the authors to assess the climate change vulnerability of residential dwellings regarding thermal comfort (Gregório, Simoes, & Seixas, 2015) and was further adapted to map fuel poverty. The potential impact is stated as the "heating and cooling gap" and the adaptive capacity is adjusted to "capacity to implement alleviation measures". These are explained more thoroughly in this section.

In this approach, we only look into the residential buildings and their needs aiming to ensure thermal comfort (space heating and cooling). We have adopted the definition of thermal comfort as stated in the Portuguese regulation on the thermal characteristics of buildings (RCCTE) of 2006 (*Decree-Law 80/2006. RCCTE - Regulamento das Características de Comportamento Térmico de Edifícios de 4 de Abril 2006 [Regulation of Thermal Behaviour Characteristics of Buildings of 4th April 2006]*, 2006) which determines that a dwelling should maintain an indoor temperature of 20ºC during the heating season and of 25ºC during the cooling season. This is applicable to the whole of the dwelling and throughout the entirety of the heating and cooling season. The outcomes of fuel poverty are expressed in terms of the senior inhabitants living in civil parishes identified as potentially fuel poor.

2.1 Assessing the potential fuel poverty of dwellings

As previously mentioned, we adapted the approach described in (Schneiderbauer et al., 2014) (Fig. 1**Erro! A origem da referência não foi encontrada.**) which entails addressing complementarily the potential impact and the capacity to implement measures to reduce potential fuel poverty.

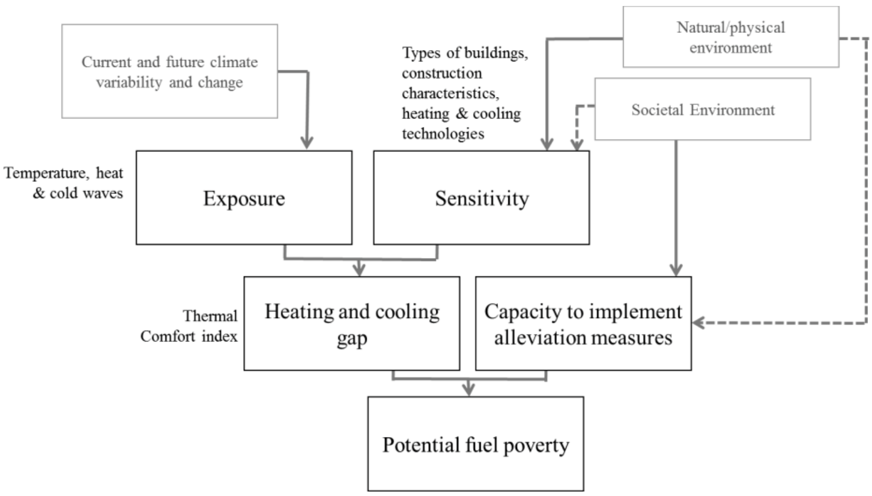

Fig. 1 - Schematic representation of the approach to assess potential fuel poverty; authors elaboration over work from (Schneiderbauer et al., 2014)

Regarding the **capacity to implement alleviation measures**, we have built an index to quantify the capacity of each civil parish in the municipality, based on five classes, varying from 0 (minimum capacity) to 5 (maximum capacity), based on detailed statistics data from the National Statistics Institute, most of them at the level of each civil parish, for each of the following variables:

- Age of resident population, particularly the share of resident population with 65 years old or more, being the underlying assumption that older people have more difficulties in adapting to climate changes;
- Average monthly gain in euros, only available at municipality level, to translate the capacity to implement fuel poverty alleviation measures, such as acquiring and using heating and cooling technologies;
- Level of formal education of the resident population, in particular the share of population with a university degree, assuming that persons with higher education have higher income and better access to opportunities to lower their fuel poverty including access to funding opportunities, such as subsidies for retrofitting or for renewable heating and cooling technologies;
- Unemployment rate, reflecting that, in general, unemployed persons will have more economic difficulties.

The five classes of each socio-economic indicator are illustrated in Table 1**Erro! A origem da referência não foi encontrada.**. These classes were validated with representatives from 3 Portuguese municipalities who are very aware of climate change adaptation at local level.

Table 1 - Five level classes of capacity to implement alleviation measures for each socio-economic indicator

Population with 65 years old or more		**Average monthly gain in euros**		**Share of population with university degree**		**Unemployment rate**	
Attribute range	Classes (0-5)	Attribute range	Classes (0-5)	Attribute range	Classes (0-5)	Attribute range	Classes (0-5)
>56%	1	>1801€	5	>26%	1	>26%	1
41-56%	2	1427-1800€	4	19-26%	2	19-26%	2
25-40%	3	1050-1426€	3	12-18%	3	12-18%	3
10-24%	4	683-1049€	2	5-11%	4	5-11%	4
<10%	5	<683€	1	<5%	5	<5%	5

The overall **capacity to implement alleviation measures** was derived through an index, ranging from 0 to 20, that combines a weighted sum as follows: the share of senior citizens weights 1.00, the monthly gain 1.00, the share of population with unemployment rate 0.75 and share of unemployed persons 1.25. These weights appear to be reasonable regarding the results achieved, although additional analysis, namely sensitivity analysis, as well as hands-on by the 29 municipalities in the near future, will be done and adjust if necessary.

Regarding the estimation of the **heating and cooling gap** in thermal comfort, we have developed an approach based on the difference between the final energy consumed for space heating and cooling in reality (stated as REAL FINAL), as reported by the DGEG-General Energy Directorate for year 2013, and the final energy that would be needed to ensure the thermal comfort levels as stated in the national buildings regulation (hereafter referred to as IDEAL FINAL). This was estimated by taking the required heating degree-days (HDD) and cooling degree-days (CDD) for different climatic zones, and the different typologies of buildings characterized by specific construction materials and envelopes. The higher that difference, the higher the heating and cooling gap on thermal comfort. This approach is depicted in Fig. 2**Erro! A origem da referência não foi encontrada.**.

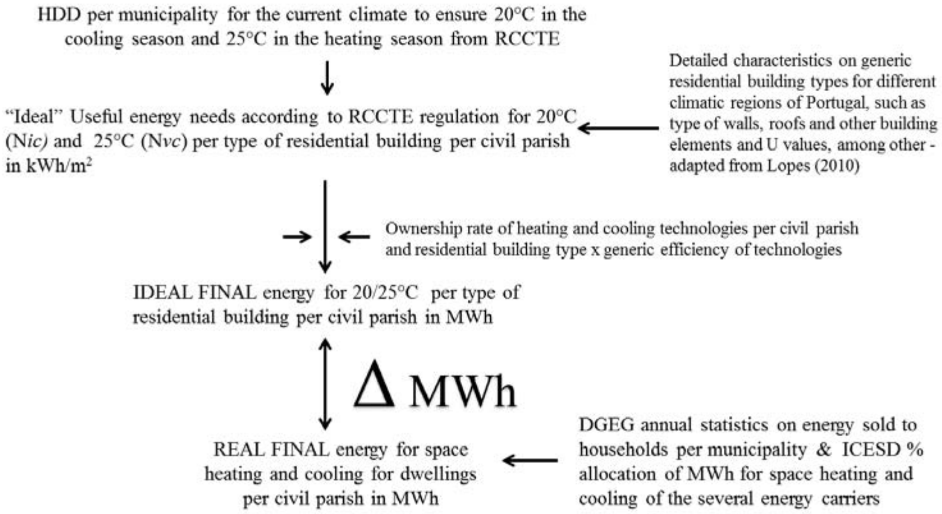

Fig. 2 - Methodology to estimate the heating and cooling gap. ICESD refers to the survey on energy consumption profiles of Portuguese Families (DGEG & INE, 2010)

We have estimated the REAL final energy consumption for space heating and cooling in the 29 municipalities based on statistical historical data produced by the National Energy Directorate (DGEG) (DGEG, 2015) for each Portuguese municipality on the sales of electricity, Liquefied Petroleum Gas (LPG), natural gas and diesel to residential consumers. We have then assumed a share of these energy carriers to be consumed in space heating and cooling following the survey of DGEG (DGEG & INE, 2010) to residential dwellings in Portugal. For energy consumption of biomass, which is quite significant for space heating in Portugal, we have assumed a value per household estimated by DGEG (DGEG & INE, 2010) since there is no robust statistics available.

The final energy consumption associated to the IDEAL thermal comfort was estimated from the calculations required according to the 2006 Regulation for Thermal Comfort Characteristics of Buildings (RCCTE) (*Decree-Law 80/2006. RCCTE - Regulamento das Características de Comportamento Térmico de Edifícios de 4 de Abril 2006 [Regulation of Thermal Behaviour Characteristics of Buildings of 4th April 2006]*, 2006) for a set of typologies of the residential building stock in Portugal, based on the work of (Lopes, 2010). We have considered six residential building types for the civil parishes of each of the 29 municipalities and estimated the useful energy needs in kWh/m^2 for space heating and cooling. We then converted the useful energy in final energy using data from the last available population CENSUS (INE, 2011) on: ownership rate of heating and cooling technologies per civil parish and building type, average area of dwellings per parish, and type of energy carrier consumed for space heating and cooling per residential building type, and average energy efficiencies of space heating and cooling technologies as in Table 2.

Table 2 - Average efficiency considered for heating and cooling technologies

Technology	Efficiency	Reference
Space heating		
Open fireplace	0.35	(Gouveia, Fortes, & Seixas, 2011)
Fireplace with heat recovery	0.60	

Technology	Efficiency	Reference
Closed biomass stove	0.55	
Boiler for central heating	n.a.	
Biomass	0.70	(ETSAP IEA, 2012)
Diesel	0.75	
Natural gas	0.75	
LPG	0.75	
Electric heater	1.00	(Gouveia et al., 2011)
GPL heater	0.85	Best guess
Air conditioning (heat pump)	2.20	(Gouveia et al., 2011)
Space cooling		
Air conditioning	2.38	(Gouveia et al., 2011)
Fan	1.00	Best guess
Heat pump	2.30	(ETSAP IEA, 2012)

The heating and cooling gap per each civil parish was classified in a 20 level index, ranging from 1 (minimum gap) to 20 (maximum gap), that was validated with technicians from municipalities. An index of 20 reveals a maximum gap, which means that highest attention regarding building envelope conditions is required to avoid negative consequences due to the lack of thermal comfort, namely on health.

Finally, the **potential fuel poverty** of households to climate change regarding thermal comfort was derived through a simple average from the combination of the **capacity to implement alleviation measures** index with the **heating and cooling gap** index, ranging from a minimum of 0 to a maximum of 20. We have arbitrarily selected as a threshold to identify potentially fuel poor persons those older than 65 years old and living in a civil parish with a potential fuel poverty index equal or higher to 10.

This methodology may be applied either for the current or for projected climate data, including heat waves episodes, for which the calculation of DCC or CDD may be adjusted.

3 RESULTS

We have applied the previously described approach to the 29 municipalities participating in the ClimAda.PT project, which comprise 679 LAU 2 civil parishes and a total of 2,926,321 inhabitants, i.e. almost 30% of the Portuguese population. These municipalities cover a widely varied context in the country including its two largest cities, as well as medium sized municipalities and several small and mainly rural municipalities. The studied municipalities cover all the different climatic zones in the country and translate fairly well the different demographic and socio-economic contexts across the Portuguese territory. This is visible in Table 3.

Table 3 – Overview of the variability of the socio-economic indicators used to estimate the capacity to implement alleviation measures at NUT 5 level for the 29 municipalities

LAU 2 variables	% of population 65 years old or older	Average monthly income (euros)	% of population with a university degree	% of population unemployed	Number of residents	Capacity to implement alleviation measures index (1-20)
Maximum	75	1590.60	44	34	66,250	17

Minimum	4	760.00	0	0	41	7
Median	22	927.71	7	12	1,345	12
Average	24	976.20	9	12	4,368	12

Reference: (INE, 2011)

In terms of the heating and cooling gap per LAU 2 civil parish, the 29 municipalities also reflect the large heterogeneity in building types, climate variables and heating and cooling habits across the country (Table 4), with the heating and cooling gap index varying from 5 to the maximum value of 20 reflecting the different building characteristics, climatic zones and behaviour of its occupants (ownership of heating and cooling equipment's and reported energy consumption at municipal level). Although the median for owning a heating device is of 94%, only 6% of the dwellings have some sort of cooling appliance. Although in some civil parishes all buildings are older than 1960 (admittedly only for a few historical areas), in most of them only 19% of buildings are older than 1960.

Table 4 – Overview of main variations in the building characteristics and some of the dwellings indicators used to estimate the heating and cooling gap at NUT 5 level for the 29 municipalities

LAU 2 variables	Share of dwellings owning of heating equipment [a]	Share of dwellings owning cooling equipment [a]	Share of buildings built before 1960[a]	Aggregate Heating and Cooling Gap Index (1-20)
Maximum	100	47	100	20
Minimum	0	0	0	5
Median	94	6	19	13
Average	89	8	25	13

[a] Reference: (DGEG & INE, 2010; INE, 2011)

The mapping of the potential fuel poor residents resulted in the aggregated values as in (Table 5). In median terms 22% of the residents in these 29 municipalities are persons older than 65 years old that live in civil parishes with a potential heating gap equal or higher than 10. Likewise in terms of cooling, 29% of the residents and potentially fuel poor in median terms. These values can range between 8-75% of residents for heating and between 10-75% of residents for cooling. Due to the number of civil parishes we have not included here all values and only a simplified statistical analysis. However, our approach allows to map, using a Geographic Information System (GIS) all these variables to identify the most critical areas (Fig. 3).

Table 5 – Overview of main variations in the potential fuel poor at NUT 5 level for the 29 municipalities per main zones in the country

Number of potential fuel poor residents (older than 65 years and living in a civil parish with a potential fuel poverty index >= 10)	Regarding Heating	Share of residents (%)	Regarding Cooling	Share of residents (%)
29 Municipalities Total				
Total	383,086		207,122	
Average	665	25	764	30
Maximum	10,496	75	12,115	75
Minimum	16	8	16	10
Median	256	22	212	29
Norte Region Total				
Average	428	24	157	34
Maximum	10,496	75	2,449	75

Minimum	16	8	16	10
Median	153	21	102	33
Centro Region Total				
Average	487	25	562	29
Maximum	5,796	62	5,796	52
Minimum	45	13	65	14
Median	303	24	299	29
Lisbon Region Total				
Average	2,105	22	2,510	25
Maximum	8,138	37	12,115	37
Minimum	188	11	66	14
Median	1,314	20	1,924	26
Alentejo Region Total				
Average	472	28	451	29
Maximum	2,411	46	2,411	46
Minimum	92	12	92	12
Median	305	28	230	29
Algarve Region Total				
Average	1,239	29	1,341	27
Maximum	3,149	50	3,149	39
Minimum	220	14	282	14
Median	956	33	1,084	28

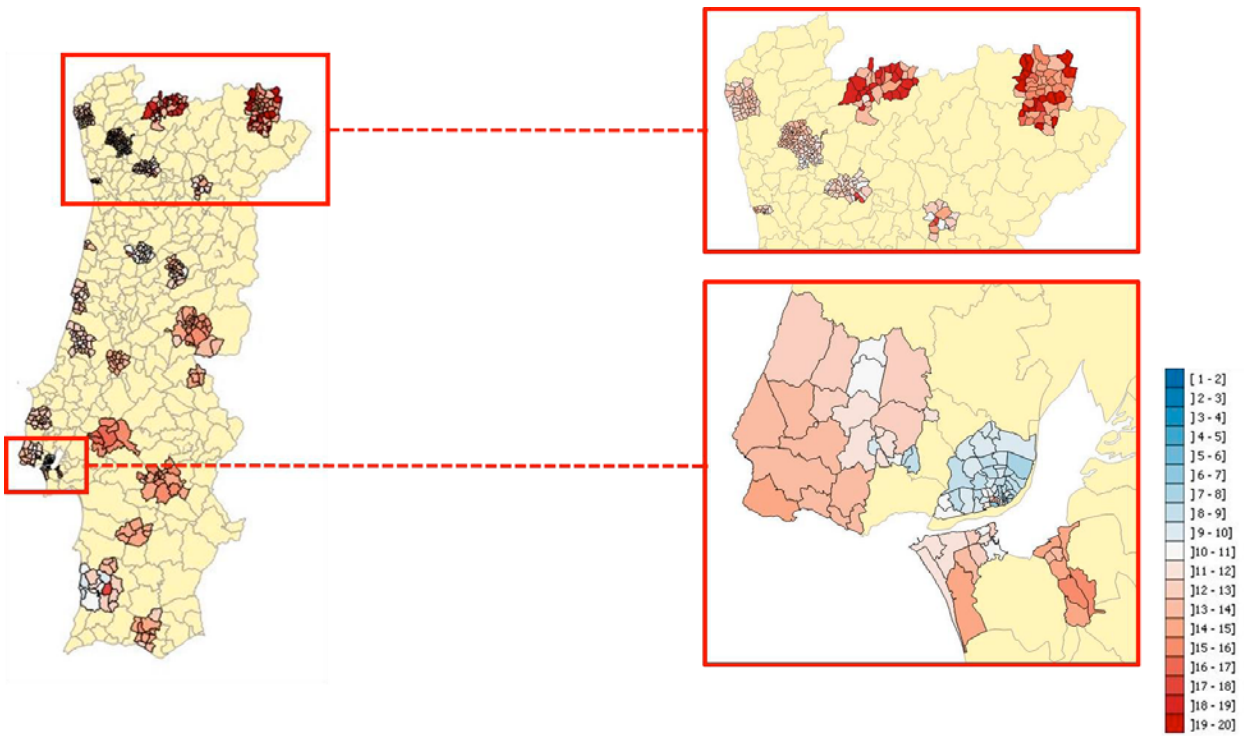

Fig. 3 – Overview of heating and cooling aggregated gap for the total of studied municipalities and civil parishes (left), highlighting the Norte (upper right) and Lisbon regions (lower right). The Azores and Madeira regions are not included.

Looking into the five different LAU1 regions (former NUT3), we verify that the parishes with higher share of potential fuel poor persons are located in the Norte region (75% of residents for both heating and cooling). This is the civil parish of Rio de Onor in the municipality of Bragança characterised by its very harsh winters and stifling hot summers, with 75% of inhabitants over 65 years old, but only with 76 residents according to the last population census. On the other extreme of the spectrum, the civil parish of Real in the municipality of Braga (also in the Norte region) has only 8% of its inhabitants potentially fuel poor regarding heating. The climate in Braga is slightly milder than in Bragança but still much harsher than in the Lisbon or Algarve regions. Nonetheless, Braga is one of the youngest municipalities in the country, Real has an educated population and no buildings built before 1960. In terms of minimum share of residents that are potentially fuel poor regarding cooling, again the Norte region leads with a share as low as 10% for the civil parish of Frossos again in Braga where 13% of dwellings own a cooling equipment. Again Rio de Onor has the highest share of potential fuel poor inhabitants regarding cooling.

Note that in Table 5 we only show the values for the civil parishes where we have identified potentially fuel poor dwellings, i.e. with a fuel poverty index for heating and for cooling equal or higher than 10. For example, the civil parish of Real has a fuel poverty index below 10 regarding cooling and thus it does not show up as potentially fuel poor regarding cooling. This is why the number of potentially poor persons regarding heating is much higher than regarding cooling. There are 410 civil parishes with a fuel poverty index for cooling below 10 in the total 679 mapped. In terms of heating only 102 civil parishes are below this threshold. This indicates clearly a different map regarding heating and cooling fuel poverty. This is of relevance as different measures might be necessary for these two different situations. This can be seen in Table 6 where we show the frequency of the heating and of the cooling index classification for the LAU regions.

Table 6 – Frequency of the LAU2 classification according to the classes of the heating and the cooling gap

LAU3/ gap index classes	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Heating																				
Açores											1	1	1	1				1	1	
Alentejo										1		1	4	2	4	13	16	5		
Algarve														1		3	2	4	1	
Centro								1		1	1	1	8	17	35	34	29	6	2	23
Lisbon	33	3	3	1	3	2		2	1	1	1	6	2	6	20	27	6	1		8
Madeira														1	5	1	1		2	
Norte													3	5	31	82	96	47	48	1
Total	33	3	3	1	3	2	0	3	1	3	3	9	18	33	95	160	150	64	54	32
Cooling																				
Açores							1	2	1		2									
Alentejo							1	2	2	10	3	8	12	6	1					1
Algarve							1				4	1	4	1						
Centro	1	1		2	2	3	15	21	17	23	44	20	6							3

Lisbon						2	4	4	12	13	21	20	19	10	16	4	1			
Madeira								1	2	7										
Norte	4	2	2	1	4	10	19	24	52	62	53	18	16	3	2					41
Total	5	3	2	3	6	15	41	54	86	115	127	67	57	20	19	4	1	0	0	45

4 DISCUSSION AND CONCLUSIONS

We have implemented an approach to assess and map the potential fuel poor across 29 municipalities in Portugal participating in the Project ClimAdaPT.Local. For the LAU 2 regions, a total of 679 civil parishes were analysed. In median terms, 22% of the inhabitants are potentially fuel poor regarding the satisfaction of their dwellings' heating needs and 29% regarding cooling needs. There is a large variation across the country in these indicators. The maximum share of potentially fuel poor inhabitants for heating is 75% and the minimum is 8%. Regarding cooling, the share varies between 22-75%. In our findings we conclude that it is extremely relevant to pay attention to fuel poverty regarding cooling particularly in Southern European countries. In these countries, due to future climate change the occurrence of heat waves with significant impact on public health will increase and with it most probably the share of potential fuel poor.

Our approach allows assessing, through a meaningful sample of the whole country, where the fuel poor are and what are their characteristics. This is considered fundamental by Dubois (Dubois, 2012) as it allows for prioritizing the necessary resources for a more precise assessment to learn where and who the fuel poor are. This is, in turn, extremely important since fuel poverty is caused by a blend of motives, which need to be dealt with differently. For example, fuel poor persons can also be economically poor, but this is not always the case. Fuel poor individuals can be elderly and living in isolation or be part of families with young children. They can be more affected by their inability to meet heating or cooling needs. They can live in apartment buildings without any heating appliances or rural houses using wood fires. Different policies need to be defined for these different types of fuel poor individuals. As written by Dubois, we can assess "who can really be helped by fuel poverty policy and who would better be helped by other policies". This is also supported by Healy (Healy, 2004) that states that "while poverty could in principle be eradicated through rising incomes with some income redistribution, fuel poverty requires more concerted policy action not only through taxation or benefits, but also in crucial investment on building stock". The assessment presented in this paper was supported by current temperature profiles, but it can be extended to take projected temperature profiles at local level, taken from future climate scenarios and extreme episodes of heat and cold waves.

The approach is relatively easy to implement for a large territory while maintaining a relatively fine geographical disaggregation –we have shown we can "map" the fuel poor potential for a country, a region or a municipality, making use of information available in most of the National Statistic Institutes across the EU. Furthermore, because the approach maps the "heating and cooling gap", we can identify where improving the building envelope will be more important and where increasing income is more relevant.

Finally, there is substantial room for improvements mainly in what regards data gathering. We have deliberately excluded at this stage the persons living in "unconventional" dwellings, which are probably amongst the most fuel poor ones. Moreover, there is large uncertainty associated to the estimation of the heating and cooling gap since the energy consumption data is only available at municipal level and not disaggregated for heating and cooling. Along these lines, there is also no LAU 2 level data available on the usage of the heating and cooling equipment's. It could be that in some cases they are not used due to a series of motives. This would influence the size of the heating and cooling gap. Likewise, it was necessary to assume a simplified representation of building typologies for each civil parish and there is no information available of the socio-economic data of the inhabitants of each dwelling. Thus, one may consider equally a wealthy senior citizen living in a luxury condominium perfectly insulated and a low income senior living in degraded apartment. Also, the threshold of 10 taken for the definition of the fuel poverty index is arbitrary and substantial differences in results will occur with a different threshold, which requires a validation process running together with the municipal technicians. Nevertheless, we believe this constitutes a valuable first step towards large scale identification and communication of fuel poverty, namely by associating the results with a GIS, as we have been doing within the ClimAdaPT.Local project.

5 ACKNOWLEDGEMENTS

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Cost Functions and Economies of Scale in the Spanish Small Power Systems

Gabriella Németh Kecskeméti[1]
[1] *CNMC, Calle Alcalá 14, Madrid, Spain, Gabriella.Nemeth@cnmc.es*

ABSTRACT

Recent regulatory changes in the Spanish Small Power Systems (SSPS) aim at reducing generation costs by putting economic incentives for new entry in both thermal and renewable installations. The goal of new policy measures is a reduction of market power of the former incumbents that currently dominate power generation in these small systems. It is also expected that new power stations, thermal or renewable, will *"push out"* high variable cost thermal plants from these systems. The aim of this paper is to explore tools for deciding which plants should be going out of the systems in order to reduce generation costs on SSPS.

Once consistent and efficient estimates are obtained for the translog cost functions of 5 different thermal technologies for power generation, the coefficients are used for calculating economies of scale values for each plant. According to current results the age of the plants is not closely related to scale values; however, installed capacity seems to be a determinant variable favouring relatively small size (below 40 MW). The optimal plants are those using diesel and coal as fuel and some CCGTs operating high number of hours. The non-optimal plants can have economies or diseconomies of scale; the first ones can be improved towards an optimal level by higher number of operating hours, while the second group should be closed down, especially if their age is higher than the established economically useful life.

In order to quantify potential regulatory saving in power generation in SSPS, aging plants with diseconomies of scale are substituted by hypothetical wind generation according the recently published technical and economic parameters. There seems to be clear reduction in subsidies in the Canary Islands, which amount to 45 M€ per year.

KEYWORDS: isolated power systems, cost function estimation, economies of scale, thermal and wind power generation

1. INTRODUCTION

Recent regulatory changes[1] in the power sector of the Spanish Small Power Systems[2] (SSPS) aim at reducing power generation cost, putting incentives for more efficient operation and fostering renewable penetration. The accomplishment of these reforms will imply the reduction of market power of the former incumbents (subsidiaries of ENDESA) that currently dominate power generation in these small systems and new power stations, thermal or renewable, will "*push out*" high variable cost thermal plants from SSPS. The aim of this paper is to explore tools for

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[1] Most relevant legal documents for SSPS are: i) Electricity Act of 24/2013; ii) Law 17/2013; iii) Royal Decree 413/2013; iv) Royal Decree 738/2015 and v) Royal Decree 1459/2014.

[2] SSPS comprehend the Balearic and Canary archipelagos and the two Spanish enclave cities in Africa, Ceuta and Melilla.

deciding which plants should be going out in order to reduce generation costs on SSPS. Such information might help to design the appropriate incentives.

Following Christensen and Greene (1974), the estimation rests on duality theory between production and cost functions and on the assumption that production is exogenous in the case of power generation. The paper focuses on estimating the variable cost functions of five thermal technologies on SSPS: CCGTs, gas turbines (GT), steam turbines (ST), coal plants and diesel plants. These cost functions allow, among other applications, to determine whether a given power plant operates in the area of increasing or decreasing returns to scale, which in turn can be used as a first filter to decide, which thermal plant should be "*pushed out*" of the corresponding system. The *a priori* expectation is that plants with fuel oil and diesel are working on the increasing average cost zone, and the CCGTs and coal plants in Mallorca on the decreasing average cost zone.

The estimation of the variable cost function uses monthly data, in 2011 and 2012, on production, input prices and indirectly on input quantities. We have information on the recognized variable cost of each plant, where the main driver is fuel cost accounting for 70-80% of variable cost. In order to mimic the costs companies face, we have recalculated the variable costs by substituting the standardized fuel component by international *free on board* (FOB) market prices.

The paper is organized as follows. Chapter 2 describes the general regulatory framework of SSPS paying special attention to economic incentives. Chapter 3 focuses on the estimation of the cost function for each technology and presents the model, data, estimation methodology and results. Chapter 4 uses results on the coefficients of the cost functions in order to decide whether plants are working under increasing or decreasing returns; this chapter also discusses potential reduction of additional regulatory payments by taking out of the systems aging power plants operating under decreasing economies of scale and substituting them by windmills. Finally, Chapter 5 draws the conclusions.

2. REGULATORY ISSUES IN SPANISH SMALL POWER SYSTEMS

2.1. Two different regulatory frameworks for generation

Two different regulatory frameworks coexist in Spain for power generation: mainland and SSPS. On the one hand, the power sector on mainland Spain was liberalised in 1998 and energy production could be sold under market conditions[3] since then; most generators used to receive the MIBEL market prices and retailers pay exactly those prices and bilateral agreements are also allowed.

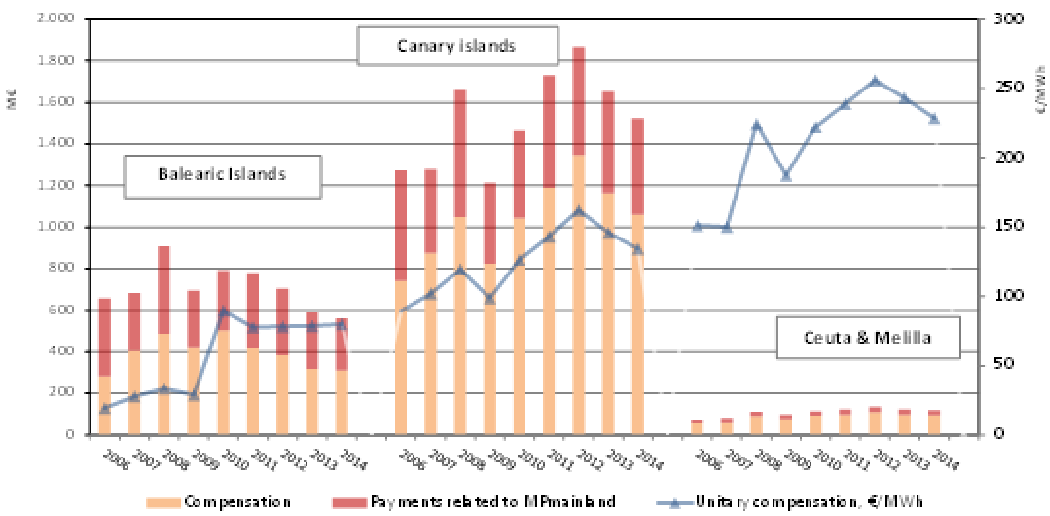
On the other hand, in SSPS the power sector was traditionally operating under a rate of return (RoR) regulatory scheme with a two part tariff structure; effective unbundling started in the early 2000s and elements of incentive regulation (PCI-X type) were introduced by Royal Decree 1747/2003. The most important component of the recognised variable cost part used to be fuel cost adjusted periodically to market prices. Recognised fixed costs used to be based on

[3] Market conditions imply that power producers or their representatives can sell their production in different markets, like on the day-ahead, intraday or balancing markets; they can also sign bilateral contracts with their counterparts and can participate in the forward electricity market.

investment recovery (with RoR equal to the 10-year Spanish state bonds plus 200 bp, thermal units with 25 years of useful economic life and straight line depreciation) and on fixed O&M costs[4]. The aging nature of the generation park in SSPS was a consequence of regulation that not only covered variable cost, but also kept paying part of the fixed costs due in year 25 of operation. As a result, in 2012 there were 39 installations (642 MW effective capacity installed) operating in SSPS that were over their established economically useful life; to put it in other words, more than 27% of installed thermal capacity on the Balearic Islands and more than 40% on the Canary Islands were older than 20 years. This means that in the short run a significant amount of installed capacity could potentially be replaced either by thermal or renewable installations.

Figure 1 shows, both in absolute value [M€] and in unitary terms [€/MWh], the two components through which recognised total cost (fixed + variable) of thermal power plants used to be remunerated: component 1 (red) refers to the day-ahead market price of MIBEL, while component 2 (orange) stands for compensation calculated in a way that allowed covering total recognised costs. Very high compensation paid for generation in SSPS above market price can be observed: in 2014 the weighted average day-ahead market price on the Peninsula was 41,5 €/MWh. In the SSPS power generators additionally received compensation that reached almost 80 €/MWh in Balearic Islands, 134 €/MWh in Canary Islands and 230 €/MWh in Ceuta and Melilla.

Figure 1. Total cost of thermal generation in SSPS [M€] & unitary compensation [€/MWh]



Source: CNMC data and own calculations

Reducing total exploitation costs in SSPS, limiting new investments of former incumbent and putting incentives for renewable installations in SSPS have been the mayor regulatory goals in

[4] Some of these recognised cost elements (start-up costs, logistic costs and fixed O&M costs) are subject to annual indexation of PCI-100 basic points and recognised capital investment is indexed to the annual IPRI.

the recent years. The new regulatory framework presented in RD 738/2015 also includes strong incentives to boost technological improvement and availability of thermal power plants[5].

2.2. Lack of renewable penetration in SSPS

The regulatory framework for renewable generation is common in the two regimes, with the same *feed-in tariff* (FIT) system in force until June 2013 and essentially the same regime afterwards, with some specific incentives included for insularity. On the Peninsula a massive penetration of wind, PV and CSP installations took place that led to 57% renewable share over total installed capacity and 43% renewable share of total production by 2014; whereas on SSPS, in spite of abundant wind resources and solar insulation, the Balearic Islands covered only 3% of demand with wind and PV, and on the Canary Islands it reached 8% of demand (see Table 1).

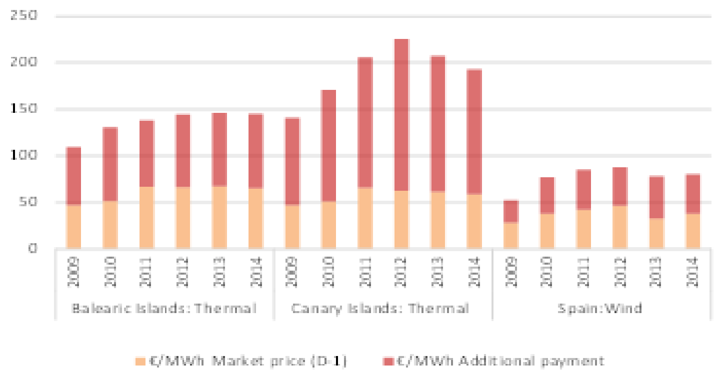
Table 1. Renewable penetration in SSPS: share of renewable production over total production in each power system

Archipielago	Power systems	2009	2014	Archipielago	Power systems	2009	2014
Balearic Islands	Mallorca-Menorca	2%	3%	Canary Islands	La Palma	5%	11%
Balearic Islands	Ibiza-Formentera	0%	0%	Canary Islands	La Gomera	1%	1%
Canary Islands	Gran Canaria	8%	9%	Canary Islands	El Hierro	1%	2%
Canary Islands	Tenerife	6%	8%	Ceuta	Ceuta	0%	0%
Canary Islands	Lanzarote-Fuerteventura	4%	4%	Melilla	Melilla	3%	4%

Source: CNMC database, own calculations.

Note: Renewable includes PV, wind, hydro and biomass, but not waste and waste treatment.

Figure 2. Remuneration of thermal plants in Balearic and Canary Islands vs in wind installations in overall Spain [€/MWh]



Source: CNMC data and own calculations

[5] This is achieved by putting a severe penalty of losing the fixed cost part of remuneration for one year in case a thermal installation is available less than 70% of the hours of the year. In case the plant does not fulfil this requirement for the second time, it would lose the fixed cost part of its remuneration forever. Moreover, in case the plant keeps on operating longer than the established economically useful lifetime and does not accomplish additional investments, it would receive a fixed annual payment equal to the fixed O&M costs, as before, but it might receive additional payments (compensation) only during 5 more years.

As Figure 2 illustrates wind technology in Spain has a significantly lower unitary remuneration on average than that of thermal technologies in SSPS. The total remuneration in both cases can be decomposed into two terms just as mentioned before only for the thermal plants: 1) MIBEL day-ahead market price and 2) additional payment, which in case of thermal units used to be called compensation and in case of renewable generation: *premium* (or *special payments*).[6]

Despite the large differences in additional payments referred to above, no significant amount of wind capacity was installed in SSPS. This could be due to the dominant position of the former incumbent, to bureaucratic red-tape and to the existence of technical barriers for the integration of intermittent generation (e.g.: wind or PV) in these small power systems with low inertia. Therefore, it is crucial to put efficient pricing mechanisms to ensure the entry of efficient plants and the exit of high cost ones.

3. ECONOMETRIC ANALYSIS OF THE COST FUNCTION OF THERMAL POWER PLANS

From a regulatory perspective, cost estimation is of crucial importance since it can reduce the information asymmetry between the regulator and the firms. As a consequence, it can help to improve the adjustment of standardized costs and put adequate incentives for more efficient operation of regulated activities. The mayor goal in the present analysis is to obtain the coefficients of the cost function of power generation in order to calculate scale economies for each plant by technology and system.

One of the first empirical approaches of estimating cost functions of the electrical power industry was done by Nerlove (1963) for the U.S. in 1955 and the author used the obtained coefficients for calculating scale economies. Christensen and Greene (1976) repeated the estimation of the dataset on the power generation units in the U.S. used by Nerlove, and it was extended with data from 1970. Their aim was not only to estimate scale economies, but determine the elasticities of substitution of input factors and study technological change in time (from 1955 to 1970). Recent literature on the estimation of translog cost functions has identified endogeneity problem, which was not treated in the mentioned articles. As Davis and Garcés (2010) denote in chapter 3 on the *Estimation of Cost Functions*, there is a contradiction in our expectation on efficient firms: they should be the ones producing a given level of output with relatively less inputs, and at the same time there is expected to be a scale effect, where bigger firms have competitive advantage in production. These two conditions might lead to endogeneity, in which case valid instruments should be found.

By constructing the cost function, it should be borne in mind that duality theory rests on two main assumptions: 1) cost minimising firms for a given level of output at a given point in time, and 2) price–taker firm in the input markets. We accept that the power generation units, although regulated and with guaranteed return, minimize cost in order to obtain higher benefits. The indexation and the incentives of type (PCI-X) also aim at forcing the firm for minimizing cost. We also accept condition 2; however, it should be noted that ENDESA, as a holding, buys fuel,

[6] In Figure 2 payments related to market prices are based on the same hourly market prices both for wind technology and for the thermal units in SSPS. However, the observed differences are due to annual averages and to the differences in the load curves of the different technologies.

the most important input, by means of long term contracts (which will be mimicked by low international FOB prices).

3.1. **The empirical model**

The empirical model is carried out by constructing a *translog cost function* for the thermal production units. The translog functional form has been chosen for the analysis since it has convenient properties for our purposes: 1) it approximates a general production procedure without forcing specific functional relationships among the variables and 2) it yields input demand functions that are linear in their parameters.

3.1.1. The translog cost function

The specification of the model as a second order translog cost function is defined for each of the 5 technologies (CCGT, steam turbines, gas turbines, coal plants and diesel plants) in the following way:

$$[\boldsymbol{eq1}]\quad lnVC_k^m = (\alpha_k + \psi_k SYS_k + \delta) + \alpha_Y lnY_k^m + \frac{1}{2}\beta_{YY}(lnY_k^m)^2 + \sum_i^I \alpha_i lnP_{ki}^m + \frac{1}{2}\sum_i^I\sum_j^J \beta_{ij} lnP_{ki}^m lnP_{kj}^m + \sum_i^I \beta_{Yi} lnY_k^m\, lnP_{ki}^m + \sum_r^R \varphi_r A_{kr}^m + \frac{1}{2}\sum_r^R\sum_s^S \varphi_{rs} A_{kr}^m A_{ks}^m + \sum_r^R \mu_r (lnY_k^m) A_{kr}^m + \frac{1}{2}\sum_r^R\sum_i^I \lambda_{ri}\, lnP_{ki}^m A_{kr}^m + \varepsilon_k^m,$$

where indexes (i) and (j) identify inputs (fuel prices $\{f\}$, unitary variable O&M $\{om\}$ and recognized logistic prices $\{log\}$), i≠j; (r) and (s) are indexes for attributes of output characteristics, r≠s; index (k) denotes individual production units; (m) stands for months, the estimation is done on the period of Jan-2011 – Dec-2012; $(lnVC_{ki}^m)$ is the natural logarithm of variable costs of each unit in each month [expressed in €]; lnY is the natural logarithm of production [MWh]; (lnP_{ki}^m) stands for the natural logarithm of input prices of each unit k in month m taking [€]; (A) characterizes output and considers age [in months], hours of operation[7] [h], number of different start-ups and frequency restoration reserve [MW]. A seasonal time dummy (δ) is introduced mimicking the load curve of demand in the different systems according to seasons [δ: 1=peak, 2=plain, 3=off-peak][8].

Restrictions on homogeneity of degree one are imposed on the equations. As there are several inputs, we should put the restriction of $\sum_i \alpha_i = 1$; this normalisation implies that the sum of the share of each input adds up to total cost. This restriction leads to the following:

$$[\boldsymbol{eq2}]\quad \sum_i \alpha_i lnC(\lambda P_i) = \sum_i \alpha_i (ln\lambda + lnP_i)$$
$$= \sum_i \alpha_i (ln\lambda) + \sum_I \alpha_i lnP_i) = (ln\lambda)\sum_i \alpha_i + \sum_I \alpha_i lnP_i)$$

In our case, it implies that the coefficients of input fuel (α_f), input logistic (α_{log}) and input of variable price for O&M (α_{om}) sum up to 1 leading to:

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[7] Hours in a month, in which the group has produced energy. It is to be noted that this is not the equivalent hours of operation, which would be the ratio between energy produced and MWs installed.

[8] Order ITC/914/2006 Article 3.4. and RD 738/2015

Restriction1: $\alpha_f + \alpha_{log} + \alpha_{om} = 1$

Homotheticity is also a requirement for the cost function, so if the cost function is f(x)=g(h(x)), then h(·) is homogenous of degree 1 and g(·) is a monotonously increasing function. This leads to the fact that the coefficient of the cross terms of output and input prices sum up to zero, $\sum_i \beta_{Y,i} = 0$, and so do the cross terms of input prices, $\sum_i \beta_{i,j} = \sum_j \beta_{i,j} = \sum_i \sum_j \beta_{i,j} = 0$. These restrictions in our model imply the following:

Restriction2: $\beta_{Y,f} + \beta_{Y,log} + \beta_{Y,om} = 0$
Restriction3: $\beta_{ff} + \beta_{f,log} + \beta_{f,om} = 0$
Restriction4: $\beta_{log,f} + \beta_{log,log} + \beta_{log,om} = 0$
Restriction5: $\beta_{om,f} + \beta_{om,log} + \beta_{om,om} = 0$

In ***[eq1]*** the coefficients denoted with α stand for measuring the effects of the first order explanatory variables and the constant term. The coefficients β are linked to the second order terms, all together we have 10 βs given that we impose the restriction of symmetry among them: $\beta_{Y,fuel} = \beta_{fuel,Y}$, $\beta_{Y,log} = \beta_{log,Y}$, $\beta_{Y,om} = \beta_{om,Y}$, $\beta_{log,fuel} = \beta_{fuel,log}$, $\beta_{om,fuel} = \beta_{fuel,om}$ and $\beta_{log,om} = \beta_{om,log}$. The coefficients ϕ, λ and μ relate the output characteristics among each other and among production and input prices, the symmetry restrictions are also assumed in these cases.

3.1.2. Input share equations

By recalling Sheppard`s lemma, the translog cost function approach allows for the identification of the derived demand functions by partially differentiating the cost function with respect to input factor prices, that is:

$$[\boldsymbol{eq3}] \quad \frac{\partial lnVC_k^m}{\partial lnP_{k\ i}^m} = \frac{P_{k\ i}^m X_{k\ i}^m}{VC} = S_{ki}^m = \alpha_i + \sum_j^J \beta_{ij}\, lnP_{kj}^m + \beta_{Yi} lnY_k^m + \sum_r^R \lambda_{ri}\, A_{kr}^m + \boldsymbol{\varepsilon_{ik}^m}$$

where S_i is the cost share of the i-th input factor, which is derived from the *translog* cost function as shown, and X stands for quantity of input used. By estimating the cost function together with two out of the three share equations (one is omitted for being redundant), we obtain more stable coefficients, lower variance of the residuals and we can also avoid the severe multicollinearity present when estimating the cost function.

3.2. **The dataset**

The empirical analysis and the specification of the translog cost function are carried out on the basis of fuel audits of the companies[9], all broken down to monthly data for each thermal generating unit. From the perspective of the translog cost system estimation the most valuable variables are the fuel mix (fuel quantities by type in each plant), variable O&M costs and the information related to start-ups. The rest of the variables used in the estimation are adjusted to the timeframe of the audited dataset, which covers 24 months, from January 2011 to December 2012 and the analysis is carried out on a pooled dataset for each technology type. Auxiliary units are not considered here and the only cogeneration unit, with similar payment regime as the rest of thermal plants, was also excluded given its unique technology and fuel use.

The pooled dataset is composed of 3.400 observations along the 24 months; however, the valid estimations are carried out and adjusted for each technology group in order to take into account proper underlying characteristics of each of them. Diesel technology, which uses different kinds of fuel oil, diesel oil and gas oil as combustible, is the one with the highest number of observations (2.096) since it is present in all systems (in La Gomera and El Hierro islands diesel is the only technology operating at the time).

Diesel units are generally small, the majority of them below 10 MW of effective capacity, and they were installed mainly in the 1990s. The newest are the CCGT units (181 obs.) installed in Mallorca, Gran Canaria and Tenerife, which use natural gas in the Balearic Islands, but high cost gasoil in the Canary Islands due to the repeated postponement of the regasification plants. Coal plants (92 obs.) are the biggest ones, only present in Mallorca and operate in base load. Steam turbines (216 obs.) and gas turbines (815 obs.) are middle in size and some of them got integrated later in the CCGTs.

The explained variable [lnVC] is the natural logarithm of total variable cost, which is a *proxy* for the real cost firms face and for this reason it has been recalculated on the grounds of input use reported by companies. VC is the sum of recalculated fuel product costs using low FOB prices for each type of fuel, recognized logistic costs (BOE publications) and the firm-reported variable O&M costs[10].

Total cost is not included in this estimation because, as Petrin and Poi (2004) also appointed, investment is a questionable variable with erratic changes: it is high at a certain point, then zero for many periods. Moreover, amortization is an auditing strategy adopted by each firm and we have decided not to use this information in the estimation and focus on variable cost assuming a cost minimization behavior.

[9] Resolution approved on 4 December 2010 by the Ministry of Industry makes mandatory to the firms to hand-in fuel and costs audits, detailed with monthly frequency [Resolución de DGPEyM por la que se establecen los criterios para la realización de auditorías de los grupos de generación en regimen ordinario de los Sistemas Eléctricos Insulares y Extrapeninsulares].

[10] Variable O&M cost includes costs related to the operation of the unit, which are related to start-ups, working capital and fungible goods and also labor cost. This way labor costs are not accounted for separately; nevertheless labor costs represent a low share in terms of annual total (2.3%) and variable cost (2.9%) and given the timeframe of the analysis (24 months) this input factor could be considered constant.

3.3. **Results of the translog cost function estimations**

The estimation method used for the characterization of cost levels of thermal technologies was adapted to several features: estimate a system of interrelated equations, control for endogeneity, multicollinearity, heteroskedasticity and restrictions. A system of equations was estimated with a three-stage least squares (3SLS) method (*reg3*) for each technology separately in order to account for their similar production patterns. This method offers more precise results and also captures the unobserved characteristics of each technology that otherwise would have been lost or would have caused biased results.

In order to control for endogeneity problems in the model, we applied the Hausman test on the cost equations (eq1) for each technology. Our assumption was that the variable on monthly production (lnY) was correlated with the error term. Thus we checked two possible instrumental variables (IV) in line with literature: 1) effective capacity installed in each month (lneffcap) and 2) the first lag of production (L.lnY).

We considered that these IVs were correlated with production, but they were uncorrelated to the error term. However, by applying the Hausman test we could only prove the existence of endogeneity problem in the case of technologies GT and diesel, where the hypothesis of lnY being exogenous was rejected at a significance level of 10% for GT and at 0,1% for diesel plants. Thus, the two IVs were introduced in the system of equations. In the cases of CCGT, coal and ST technologies the monthly production was proved exogenous, so no IV was necessary to be included. The following table shows a summary on the system of equation regression results of the main variables indicating in bold the coefficients that are not significantly different from zero at least at a 10% significance level.

Table 2. Regression results on main variables of the translog cost function estimation

	CCGT		GT		ST		COAL		DIESEL	
	coef.	st.e.	coef.	st.e.	coef.	st.e.	coef.	st.e.	coef.	st.e.
sys	**-0.004**	0.004	-0.007	0.002	-0.001	0.001	0.379	0.108	-0.005	0.003
α_Y	1.549	0.108	0.698	0.034	1.085	0.131	0.595	0.024	0.755	0.016
α_f	-0.247	0.059	0.489	0.057	-0.152	0.042	0.538	0.073	-0.186	0.024
α_{log}	0.198	0.063	0.168	0.053	0.420	0.049	-0.024	0.005	0.721	0.023
α_{om}	1.049	0.069	0.343	0.025	0.732	0.046	0.486	0.073	0.465	0.007
β_{YY}	-0.134	0.014	-0.024	0.007	**0.002**	0.029	0.137	0.015	0.022	0.005
β_{ff}	**-0.008**	0.009	-0.073	0.013	0.124	0.008	0.070	0.013	0.142	0.005
$\beta_{log,log}$	**-0.006**	0.008	-0.024	0.014	-0.084	0.009	-0.354	0.015	-0.020	0.005
$\beta_{om,om}$	0.050	0.007	0.090	0.004	0.097	0.004	0.121	0.008	0.064	0.002
$\beta_{Y,f}$	0.111	0.006	0.081	0.003	0.034	0.003	-0.009	0.005	0.026	0.001
$\beta_{Y,log}$	-0.024	0.007	-0.046	0.003	0.010	0.004	0.026	0.004	-0.011	0.001
$\beta_{Y,om}$	-0.086	0.007	-0.035	0.004	-0.044	0.005	-0.017	0.008	-0.015	0.001
$\beta_{f,log}$	0.032	0.008	0.094	0.013	0.028	0.007	0.203	0.016	-0.029	0.005
$\beta_{f,om}$	-0.024	0.004	**-0.020**	0.005	-0.152	0.005	-0.272	0.008	-0.113	0.002
$\beta_{log,om}$	-0.026	0.006	-0.070	0.005	0.055	0.005	0.151	0.008	0.049	0.002

These are the efficient and consistent coefficients of the final models for each technology. The F-tests reported that the variables were jointly significant in all cases and it can be seen that the imposed restrictions on the system of equations, described in chapter 3.1, are all fulfilled.

4. SCALE ECONOMIES AND SAVING OPPORTUNITIES

This section uses the previous estimations to decide whether SSPS power plants are working under economies or diseconomies of scale. This classification may be used to explore options to reduce costs exploitation in these systems.

4.1. Framework for calculating scale economies

In essence, economy of scale (*ESC*) measures the relationship (distance) between the average cost (*AC*) and marginal cost (*MC*) curves given the production level of a plant. Mathematically it can be calculated by deriving the cost function with respect to production and taking the inverse of this result; applying our annotation in [$eq1$], this can be expressed formally as follows:

[eq4] $$ESC = \left(\frac{\partial \ln \text{VC\_fob}_m^k}{\partial \ln Y_m^k}\right)^{-1}$$

The relationship between ESC, AC and MC can be seen by considering that $\frac{\partial \ln \text{VC\_fob}}{\partial \ln \text{Y}} = \frac{Y}{\text{VC\_fob}} \frac{\partial \text{VC\_fob}}{\partial \text{Y}} = \frac{MC}{AC}$, which leads to $ESC = \left(\frac{\partial \ln \text{VC\_fob}_m^k}{\partial \ln Y_m^k}\right)^{-1} = \frac{AC}{MC}$. The firms obtain the optimal production level on the long run when $AC = MC$, that is, $ESC = 1$. They will obtain increasing returns to scale if $AC > MC$, and the firm still has scope for achieving the optimal level by increasing its production level. However, if the opposite is true, $AC < MC$, the firm will produce with diseconomies of scale, which can be improved, if technically possible, by reducing production and it might also indicate room for potential new entry.

4.2. Results on scale economies

Once efficient and consistent estimates for the system of equations are obtained, the coefficients are used to calculate the value for scale economy of each plant given their level of power production in every month. The individual results in each month give a first glimpse on all the observations permitting a quick comparison among the technologies. We can observe that GT, diesel plants and also the CCGTs (to a bit lower extent) show overwhelmingly positive economies of scale with scale values above 1; ST and, especially, coal plants present diseconomies of scale.

In order to analyze the performance of each plant in more detail, we take the arithmetic average[11] of their scale value along the whole period and classify the plants in the following 3 groups:

[11] By taking the averages we have paid attention to the sign of each scale value for a given firm in order to avoid potential bias due to opposite signs that could cancel each other out. The only plants that present negative scale values are the coal plants; however, given that all coal observations have negative values, taking their average will not cause any problems.

Group 1. Plants with scale value in the interval *0.95 < ESC < 1.05*. These plants have an optimal scale and operate with CRS in the long run.
35 plants out of the 153 of the total number of plants considered are in this group, they are diesel and coal plants and a CCGT. They are spread over the 10 SSPS, except for La Gomera Island, and 95% of them have been operating on average at least 56% of the time in a month.
With respect to the only CCGT present in this group located in the Mallorca-Menorca system, it should be noticed that natural gas is only used in Balearic Islands due to pipeline connection with mainland Spain since 2009. On the Canary Islands the CCGTs burn mainly very expensive gas oil instead of natural gas, which lowers the potential for efficiency gains. Coal plants show efficient operation given cost efficient production in high number of hours.

Group 2. Plants in this group comprise those that have positive economies of scale with *ESC > 1.05* and present IRS on the long run. However, they are further away from the optimal scale, thus their performance could be improved by increasing production. The vast majority of the plants belongs to this group (109 units) and, as expected, their average operation hours are significantly lower (19% of hours in a month) than that of the optimal scale group (67% of hours in a month). The same is true for monthly production, where the average production is half that of the optimal scale group. These plants are also distributed over all 10 SSPS.

Group 3. These are the least efficient plants with diseconomies of scale (*ESC < 0.95*), they are large units with average effective capacity of 75 MW produce on average 5 times as much as the optimal units of group 1. In Gran Canaria and Tenerife Islands are located 9 ST that present diseconomies of scale.

It should be noticed that there is a weak correlation between the age of the plants and the scale economy values. On the contrary, effective capacity is strongly correlated with scale values small groups (below 40 MW) present scale values close to unity and large groups tend to be further away from this optimal scale, either in positive or negative direction.

4.3. Options for reducing regulatory additional payments in SSPS

As mentioned in section 3.2 the compensation paid for thermal generation in SSPS is very high. This section explores to what extend amortizing aging plants working under diseconomies of scale and building wind generation according to the technical and economic parameters defined by the recent ministerial Order IET/1459/2014 would reduce the additional payments for power generation in SSPS. Notice that the remuneration scheme for thermal and for wind installations has the same structure: both are based on the day-ahead market prices in MIBEL and an additional payment.

The scale values obtained for the period 2011 and 2012 show that there are 9 plants working with diseconomies of scale, out of which 4 units (2 ST on both Gran Canaria and Tenerife) are older than 25 years. This set of 4 aging plants is in the focus of this chapter. These units have a capacity of 186 MW and produced 559 GWh of electric power in 2014. Their recognized total costs[12] reached 121 M€, which can be disaggregated into variable cost payments (110 M€) and capacity payments (11 M€). The additional payment above the reference market price in MIBEL

[12] Data assessed on 10 July 2015.

reached 64 M€ in 2014. Therefore, SSPS producers received a unitary additional payment of 115 € per MWh on average.

For calculating the potential reduction of additional payments by substituting the aging and inefficient installations, a hypothetical wind scenario[13] was built using the parameters in the Order IET/1459/2014. Under this scenario, the additional payments for windmills to produce 559 GWh amounts to 19 M€, that makes 34 €/MWh unitary additional payment, which is considerably lower than the same term for thermal plants (115 €/MWh). This substitution would imply a potential saving of 45 M€ on additional payment, which can be higher in case competitive bidding is accomplished for wind installations foreseen in the referred Order.

5. **Conclusions**

This analysis has concentrated on characterizing the cost of conventional thermal power generation units in order to explore possible saving opportunities that, at the same time, could contribute to adjust regulatory incentives in SSPS.

Regarding the exploitation of SSPS, mayor regulatory concerns are twofold. On the one hand, the costs of thermal power generation have increased considerably in the last years reaching 2,7 billion euros in 2012, which is about 30% of total remuneration of all RES-E generation in Spain; whereas thermal production in SSPS reaches only 20% that of total national RES-E production. On the other hand, there is very low penetration of renewable generation, despite of lower cost per unit of production and abundant natural resources. Recently some competitive elements have also been applied: auctions for new RES capacity and for fuel supply for thermal generation.

The empirical analysis on estimating the cost of thermal units and calculating the scale economies for each thermal plant has shown that there are 30 plants of diesel technology widespread over all systems (except for La Gomera), 4 coal plants and 1 CCGT plant in Mallorca, which produce close to their optimum size. The majority of thermal plants (109 out of 153) is on the increasing returns to scale side of the long run variable average cost curve. This implies that by increasing the production of these units they could get closer to an optimal scale. We have found 9 thermal installations, 9 steam turbine units that are on the decreasing return to scale zone. Their production should be reduced in order to reduce overall exploitation costs.

Once the aging thermal plants with diseconomies have been identified, a hypothetical wind scenario has shown a clearly positive effect of wind penetration on Gran Canaria and Tenerife Islands; potential saving simulated in these two systems for 2014 amounts to 45 M€.

Finally, we would like ask the following question for future research: why producers on SSPS do not undertake investments in wind installations? Several possible hypotheses should be tested.

[13] This scenario rests on the following pillars:

1. The required wind generation capacity for producing 1.514 GWh is 563 MW (Table 8). Notice that while the thermal plants produced the 1.514 GWh with a total maximum capacity of 413 MW, the capacity of wind generation is almost 40% larger. This figure is obtained by using the reference values for operating hours in each system included in the mentioned Ministerial Order. For simplicity, no other technical considerations were taken into account.
2. New renewable installations have to participate in competitive auctions, where the object of bidding is the additional remuneration paid above the MIBEL day-ahead market price.
3. The additional payment is the sum of payments for investment and incentives for investment.

We will point out the following ones. First, regulatory costs recognized for thermal plants are larger than real cost, so real profit of producers is larger than the regulatory one and larger than the profit from wind generation. Second, the restrictions to incumbent producer for undertaking investment on new plants (Law 17/2013) while allowing them to make maintenance investment on old power plants might be another answer. A third reason could be the uncertainty around future return of investment, which is linked to the 10 year average of state bonds plus 300 basis points. The uncertainty comes from expected fluctuation of return between one regulatory period (6 years) and another.

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Financial viability of grid-connected solar PV and wind power systems in Germany

Subhash Kumar[1], Johannes Sebastian Weida[1], Reinhard Madlener[1]

[1] *Institute for Future Energy Consumer Needs and Behavior (FCN)*
School of Business and Economics / E.ON Energy Research Center
RWTH Aachen University, Mathieustrasse 10, 52074 Aachen, Germany

Email: skumar@eonerc.rwth-aachen.de, sebastian.weida@rwth-aachen.de, RMadlener@eonerc.rwth-aachen.de

ABSTRACT

The German electricity sector is in a period of transition. Within the energy transition, Germany pursues an ambitious target to switch to a sustainable, secure, climate-friendly and affordable energy supply system. The most important aspects are the phasing out of nuclear energy, the promotion of renewable energy technologies, and the national and European objectives for the reduction of greenhouse gas (GHG) emissions. In order to achieve these ambitious goals large investments in electricity generation systems and infrastructure are necessary. Thus, a secure energy supply as well as economic and environmental viability needs to be ensured. Wind and solar energy resources are important candidates to achieve these goals. Wind and solar PV power generation depend on the geographical and metrological site conditions. Therefore, the right location is important for new-build renewable energy power plants. For PV systems, the level of on-site solar irradiation is crucial. The yield of wind turbines is mainly determined by the wind speed at the respective location. Therefore, to take the different climatic and geographical conditions of the different regions in Germany, the model is divided into three different regions. For each region, six locations with their specific conditions have been chosen for the estimation. These projections are made for the current year 2015 and the future year 2030. For the calculations, the RETScreen software is used, which has been developed by the Canadian Ministry of Natural Resources. The results of the model-based analysis show that PV systems achieve a levelized cost of electricity below 11 €-ct/kWh in 2030, with a GHG reduction potential of 133-289 €/tCO_2. The site-specific levelized cost of wind is 5.1-16.1 €-ct/kWh and the GHG reduction potential at 101-321 €/tCO_2. In light of these results, it seems to be possible to restructure the German electricity generation system in a cost-effective and also an environmentally efficient way. PV and wind energy are becoming competitive to fossil electricity generation sources due to decreasing investment costs and increasing capacity. Therefore, efforts are required in order to enhance and optimize the integration of wind energy and PV into the grid and thus to maintain energy supply security in Germany.

KEYWORDS: PV and wind energy, Germany, RETScreen, Multi-region analysis, Cost & GHG analysis

1 INTRODUCTION

Primary energy consumption in Germany is highest in Europe, and well ahead of France and the United Kingdom, and is ranked as the world's number seven [1]. In 2014, primary energy consumption in Germany accounted for 13,088 PJ (or 446.2 million tons of coal equivalents, Mtce) which was 4.7% less than the year before and the lowest level since German reunification due to a significantly milder weather [2].
Due to limited domestic reserves, Germany is an energy-importing country. By counting nuclear as an imported energy source the total share of imported energy in the total primary energy supply was 70% in 2013 [2]. This leads to a dependency on exporting countries, which must be reduced by a wide-range diversification of supply sources [3]. Hard coal mining has declined sharply since 1990. Despite reserves of over 83 billion tons, German coal can still not compete in the world market without subsidies [4]. Due to its low energy value, lignite consumption almost closed in Germany. Natural gas and crude oil completely depends on import from different countries. Petroleum has quantitatively the largest share in terms of energy consumption, followed by gas, and electricity. In 2013, 594.3 TWh of electricity were consumed in Germany. Renewable energy technologies have been increasing in recent years and provide a significant part of the domestic primary energy supply today [5, 2].
Final energy demand depends on economic and weather-related effects. Industry and mobility constitute the largest portion, followed by private households, and small consumers. Being an industrialized country, Germany has historically grown plenty of energy-intensive industries, such as, copper, steel, and concrete production. The share of the manufacturing sector in gross domestic product in Germany was 22 % in 2013, which is far above the EU average of 15.1% [6]. Overall, final energy demand in the manufacturing sector and mining remained relatively constant. Only in 2009, as a result of the economic crisis, there was a higher decrease by 13% to 2291 PJ. However, they recovered to some 2640 PJ by 2013. Mobility and transport consumed 2612 PJ of energy in 2013 [7]. The demand over the past few years is largely constant. It depends on size and energy refurbishment of the houses. All households spent around 2603 PJ of energy in 2013. This includes approximately 138 TWh of electricity which is equivalent to 26.9% of total electricity consumption in Germany [8]. Gas and electricity are most commonly used as final energy. Lignite has almost no importance for the final energy supply in private households. Renewable energy has gained in importance in recent years and contributed a total of 288 PJ in 2013 [2, 9].
Total installed capacity in 2014 with all power plants was 195 GW in Germany [8]. In Fig. 1, Wind power and PV has the largest share, followed by natural gas, hard coal, lignite, oil, nuclear and water.

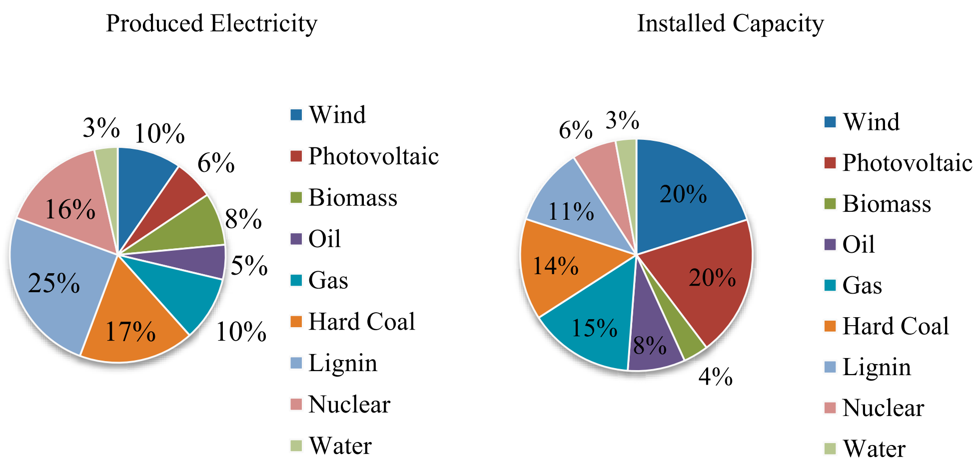

Fig. 1 Electricity generation and installed capacity in Germany by technology, 2014 [10].

The electricity generation technologies differ in their availability and utilization hours. Conventional thermal power plants such as nuclear power, lignite, and hard coal, are characterized by a high number of utilization hours per annum. They have low variable costs and default rates. On the other hand, wind power and photovoltaics depend on the weather and therefore show large fluctuations in their feed-in to the grid. Although, wind power and photovoltaics shared 39.7% of the total installed capacity, they only generated 16% of the total energy demand in 2014 [8]. On the other hand, nuclear, lignite, hard coal and gas contributed 55% to the total generated electricity despite of their comparatively low installed capacity. However, due to the increasing share of renewable but fluctuant nature, thermal power plants are still indispensable for a stable energy supply today [10, 11].

In the context of GHG emissions, Germany is the largest emitter in the European Union. However, GHG emissions have declined since 2000. In the Energy Concept, the German Federal Government has established ambitious targets for GHG emissions reduction. In 2010, CO_2 emissions from fuel combustion accounted for the largest share of GHG emissions in Germany, with a total of 81.5%. More than 75% of CO_2 emissions by fuel combustion come from coal and oil usage i.e. 41.6% and 34.2%, respectively, in 2010 [12]. The power generation sector accounted for 43.4% of energy-related emissions in 2010 [13]. By considering the government's targets and the price competitiveness along with the carbon mitigation potential, wind and photovoltaics are realistic options for future electricity generation.

In this paper, the techno-economic potentials of wind power and photovoltaics for different regions in Germany are determined. Thereafter, the power generation costs are estimated for the current year 2015. Expected future market prices based on literature review. Finally, associated CO_2 reduction costs are estimated and an assessment of the mitigation potentials carried out. The model-based computations are performed with RETScreen 4.0 (www.retscreen.net; cf. section 3.1). Overall, the present work includes an analysis of the role of grid-connected PV and wind power generation in Germany by region, a financial analysis regarding the economic viability of the projects examined, as well as an analysis of the GHG emission mitigation potentials and a sensitivity analysis.

2 OVERVIEW OF GERMAN ENERGY TRANSITION

Within the energy transition Germany pursues an ambitious target to switch from a leading industrialized nation to a sustainable, secure, climate-friendly, affordable, and nuclear power-free energy supply nation. Besides of the expansion of renewable energies and the increase in energy efficiency, energy-saving measures are important to mitigate climate change, save energy resources, and to boost Germany as a business location for sustainable and innovative development. The energy transition includes electricity, heating and mobility. Renewable energies such as solar, wind, water, geothermal, and biomass, together with the electrification of the heat sector and transportation by use of heat pumps and e-mobility play an important role in the German energy transition [9].

All energy policy decisions must be in accordance with the energy policy triangle i.e. security of supply, economy and environmental compatibility. A continuous and stable power supply is the minimum requirement of any energy policy. Power outages should rarely, preferably never, happen. High electricity prices worsen the competitiveness of industry and make Germany less attractive as a manufacturing location. Nevertheless, most important is the environmental sustainability of electricity supply to mitigate climate change and its consequences. [10,14]

According to the energy policy triangle, the German government has set targets for the energy transition. The main goals are the decrease of GHG emissions of up to 95% by 2050 compared to 1990 levels, as well as the phase-out of nuclear energy by 2022 [15]. To accomplish these ambitious goals, the German government has set acts to extend the share of renewables in primary energy supply and to increase energy efficiency. This includes the decrease in energy consumption. From these climate and environmental targets, energy consumption is to be decreased at 20% by 2020 and 50% by 2050 [16]. Gradually, energy generation is to be transformed to mainly by renewable and sustainable methods in order that renewables will provide 60% of all primary energy consumption by 2050 and at 80% of gross energy consumption. Furthermore, the final energy consumption in transportation is to be decreased by up to 40% by 2050 [17, 9].

In general, Germany is on the way to achieve these ambitious goals. Nevertheless, there is a need of action, particularly in the reduction of energy demand, the expansion of flexible thermal power plants and the coordination of network expansion with the expansion of renewable energies. The expansion targets for renewable energy technologies have been fulfilled satisfactorily, however, at very high costs [18].

The expansion of renewable energy technology is one of the main pillars in Germany's Energy Transition. It aims to rebuild the energy supply and increase the share of renewable energies in the electricity supply by at least up to 80% by 2050 [15]. Hence, the intention is to protect the environment, mitigate GHG emissions, reduce the costs of energy supply, protect fossil energy resources, and develop technology in the field of renewable energies [17,19].

The basis for the development of renewable energies is the Renewable Energy Sources Act (Erneuerbare Energien Gesetz, EEG). The main goal of this act is the promoting of relatively young technologies like wind and PV to enter the market with fixed payments, guaranteed purchase, and the priority feed-in of electricity. However, the

rapid expansion led to a high share of renewables in German energy supply system, it can also increase the reallocation charge and then electricity prices. In order to slow down any additional rise in costs, the German government has set an amendment to the Renewable Energy Sources Act. Based on this amendment, the share of renewable energy to be reached is up to 40-45% by 2025 and then to be raised further to 55-60% by 2035 [20]. In addition, concrete quantity targets for the yearly increases in capacity have been defined for each type of renewable energy technology [17,9]. The annual increase of solar, onshore wind and biomass is 2.5 GW, 2.5 GW, and 100 MW, respectively. The offshore wind installed is to be at 6.5 GW by 2020 and 15 GW by 2030 [20].
In order to reduce the costs for the further expansion of renewable energy the new Renewable Energy Sources Act focuses on less expensive technologies like wind energy and PV. Currently, the average remuneration for renewable energy is approximately 17 €-ct/kWh. Starting in 2015, operators of new plants only receive 12 €-ct/kWh [17,9].
Furthermore, the amendment obliges operators of larger new build plants to trade the electricity directly at the exchange market. Thus, the feed-in tariff is no longer an option. The main intention is hereby the integration of renewable energies into the electricity market [17,9].
Until 2022, all 12 remaining nuclear-power plants with a total capacity of 21.5 GW will be shut down. 70% are placed in the economically strong southern party of Germany. Furthermore, 10 GW of incumbent power plants are at acute risk of being decommissioned. In addition, building of approximately 17 GW of new power plant capacity by 2022 and at least an additional 10 GW by 2030 may be needed to complement the planned expansion of renewable energy to ensure adequate generating capacity and a secure supply [17].

3 METHODOLOGY

3.1 RETScreen software

There are several models available for conducting a technical and financial viability analysis of potential energy projects. The RETScreen Clean Energy Project Software provides the analytical framework to estimate energy production, financial feasibility, GHG emission reductions potentials and costs [21].
RETScreen International is a clean-energy awareness, decision-support and capacity-building tool developed by the Canadian Ministry of Natural Resources [22]. The core of the tool consists of standardized analysis that can be used to evaluate the energy production, life-cycle costs and greenhouse-gas emission reductions for various types of renewable energy technologies. RETScreen uses a computerized system with integrated mathematical algorithms. The model uses top to bottom approach. It provides a cost analysis, greenhouse gas emission reduction analysis, financial summary and sensitivity analysis.

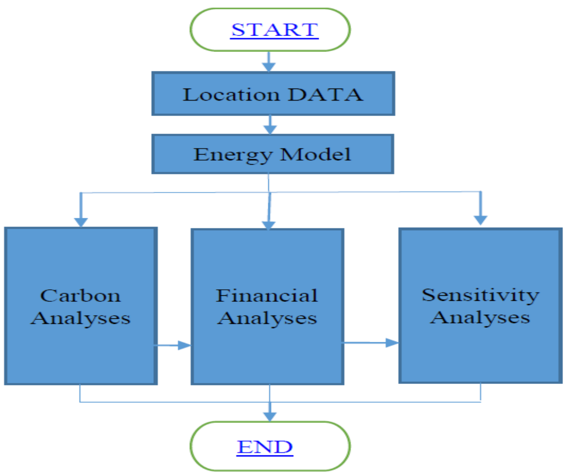

Fig. 2 Flow process for a techno-economic analysis in RETScreen.

RETScreen provides a low-cost preliminary assessment of RET projects. The software has flexibility options that allow users to select more complex frameworks, which require more information but have more accurate and detailed results, or basic frameworks for quick and inexpensive calculations. RETScreen uses built-in calculations to make the program requiring less detailed information and less computational power. For instance, other models like HOMER, use hourly global solar radiation (GSR) levels for an entire year. That makes 8760 individual values in total while RETScreen uses the monthly average GSR levels with only 12 values [23]. A comparison between the RETScreen model and more in-depth models using hourly values instead of monthly values showed that they have roughly the same results, with an annual difference of less than 5% for projected energy production [24]. RETScreen convinces with adequate and comparable results, as well as, well integrated power plant and metrological data. It has been already used for many countries and has a large user community. The flow chart in Fig.3 illustrates the standardized RETScreen model with its five-step analysis.

The energy yield from a fictitious PV power plant is estimated using the annual average solar irradiation, temperature and humidity coefficients, inclination of the sun, and technical specifications such as efficiency and losses of the system. RETScreen then uses the energy estimation to determine the financial feasibility, as well as, the GHG emission reduction prediction of the proposed project.

Within the GHG analysis, RETScreen determines the annual greenhouse-gas emission reduction for clean-energy technologies compared to a conventional technology base case. The results are given in terms of the amount of carbon dioxide that would be equivalent to the emission reduction. Methane and nitrous oxide emissions are converted into carbon dioxide equivalent emissions. The calculation itself is simple: the difference in the GHG emissions per unit of energy delivered is multiplied by the end-use annual energy delivered. RETScreen accounts for transmission and distribution losses as well [21].

RETScreen's financial analysis accounts for the benefits of the electricity produced and the costs of the RET power plants. These estimates are then used to show financial statistics, such as the net present value (NPV), simple payback period (SPP), and internal rate of return (IRR) of the project. The cost estimate is made up of the initial costs, annual costs, periodic costs, and end-of life costs. The financial analysis is the key element of the RETScreen model. Input parameters are the capacity, the energy exported to grid, and the technology-specific mitigation potential for RET. LCOE and GHG emission mitigation costs are calculated as the final output value [22].

The sensitivity analysis provides an estimation of the sensitivity of important financial indicators - such as initial costs – in relation to key technical and financial parameters. RETScreen calculates the sensitivity of LCOE regarding initial and annual costs, debt ratio, discount rate, and debt interest rate.

3.2 **Quantitative Framework**

The competitiveness of RET depend, in addition to the side-yield and finance parameters, on the initial and annual costs. It is now important to notice that these costs are only suitable for the German market. They differ globally due to various taxation systems, duties, or market development. The project size has a significant impact on the investment costs due to scale effects. Usually, larger the project, lower the investment costs per kW. The cost assumptions for this work are based on a study by Fraunhofer-ISE and levelized cost of electricity (LCOE) estimates [25]. The projection of the specific technology costs for 2030 is are based on a learning curve model. Specifically, for solar PV, a learning rate of 15% is assumed, while for onshore wind it is 3%. The initial and annual operating and maintenance costs include end-of-life and periodic costs [25].

For the calculation of levelized cost of electricity and GHG reduction costs, it is crucial that all occurring cash flows are recognized either in nominal or real terms. Mixing real and nominal variables is inadmissible. An estimation based on nominal values requires a prediction of the annual inflation rate by 2030. Since the projection of inflation rates over long periods are very imprecise and difficult the cost projections for long periods are carried out with real values. Therefore, all costs specified in this study are related to real values of 2015. In an established facility, the average electricity production costs remain constant over the life period.

The yield of RET differ due to geographical differences in solar irradiation, wind speed, air pressure, ground temperature, and humidity. For PV systems, the solar irradiation is crucial. The yield of wind turbines is mainly determined by the wind speed at the respective location. Therefore, to take into account, different climatic and geographic conditions of the different regions in Germany, the model is divided into three different regions. For every region, six locations with their specific conditions are chosen for the estimation.

- Region 1 contains the northern states of Germany, and is defined by a high wind yield and intermediate to low solar irradiation. With the exception of the densely populated areas of Hamburg and Bremen, fewer large centers of electricity consumption exist in this region, and the topography is mostly flat.

• Region 2 contains the middle of Germany. It is defined by intermediate solar irradiation and wind speed. The region includes the energy industry-significant lignite mining areas of Brandenburg, Saxony, Saxony-Anhalt, and North Rhine-Westphalia. It also contains the Rhine-Ruhr region, the largest electricity consumption center in Germany.

• Region 3 contains mainly the regions Bavaria and Baden-Wuerttemberg and is defined by a high solar yield and low wind speed. In this region, the large electricity consumption centers are Munich, Stuttgart, and Ingolstadt.

Fig. 3 illustrates the regional division of Germany adopted. The delamination lines are roughly approximated to the topography and the solar irradiation regions.

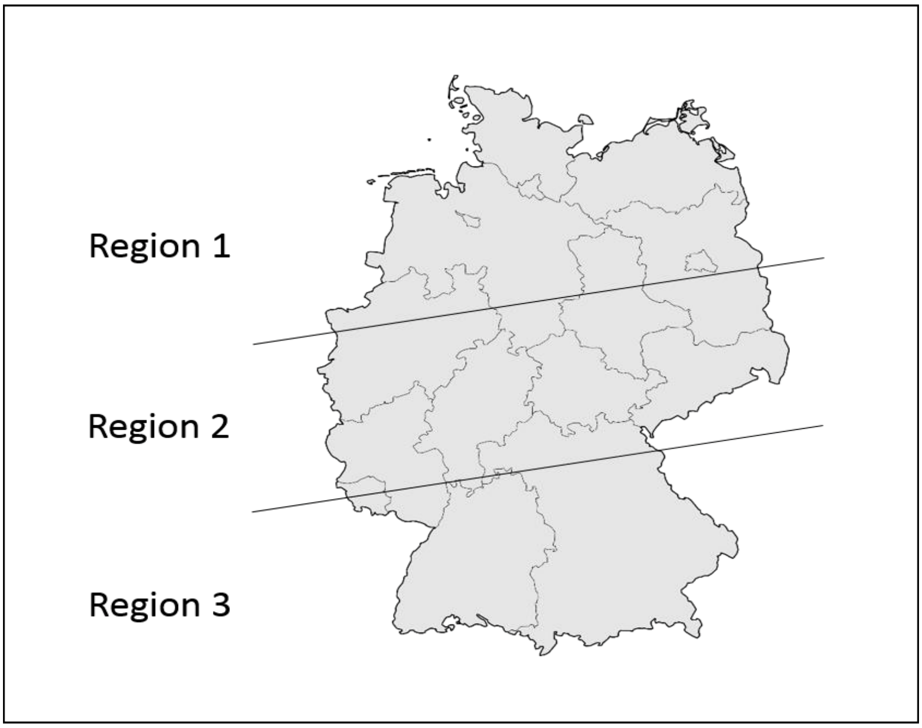

Fig. 3 Regional division of Germany adopted in this study.

In Germany, solar irradiation occurs in the range of around 950-1250 kWh/(m²a) on the horizontal surface. The wind speed, usually measured at 10 m above the ground, is mainly between 2-5 m/s [26]. Table1 shows the average range of annual wind speed and solar irradiation for the three regions considered.

Table 1. Average wind speed and solar irradiation in the regions in Germany investigated [26].

Region	Solar irradiation [kWh/(m²a)]	Wind speed [m/s]
1	1100-1250	2-3
2	1050-1100	3-4
3	950-1050	4-5

Wind speed and solar irradiation are the key parameters for the respective locations. Humidity, air pressure, as well as the average ground temperature also has an impact on the yield of RET. Air pressure and temperature influence the air density, which in turn affects the energy transported by wind. Rising temperatures decrease the energy output of a PV system significantly, whereas humidity affects the life span.

In order to accurately predict the electricity generation from the solar module, RETScreen requires site-specific global solar irradiation values. RETScreen uses monthly average values for the calculations. Fig. 4 shows the average monthly solar irradiation for different regions. The data are adopted from the historical renewable energies data provided by NASA [26]. For simplicity reasons, these are assumed to be constant over the years.

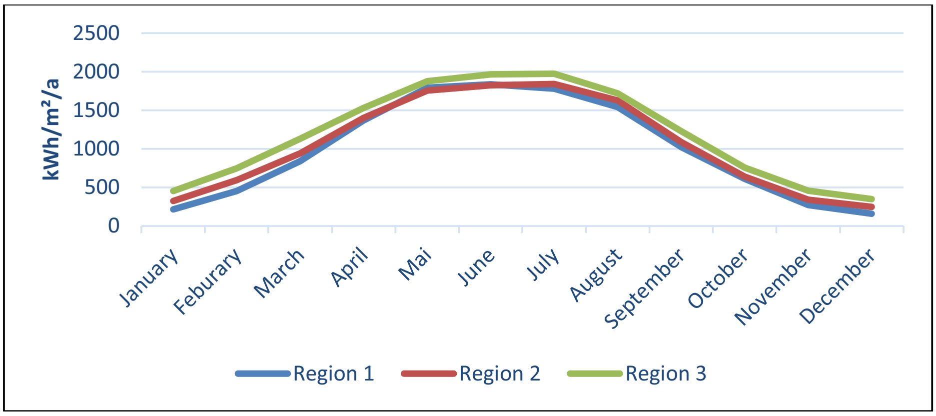

Fig. 4. Average monthly solar irradiation for different regions in Germany [26].

Region three has the highest average solar irradiation throughout the year, followed by region two, and region one. In summer, the average monthly solar irradiation has its peak for all three regions and in winter it is minimum. Fig. 5 shows the average monthly wind speeds for different regions in Germany, measured at 10 m height. Region one has the highest average wind speed, followed by region two, and region three. In contrast to the solar irradiation, average annual wind speed has its peak in winter and its minimum value in summer.

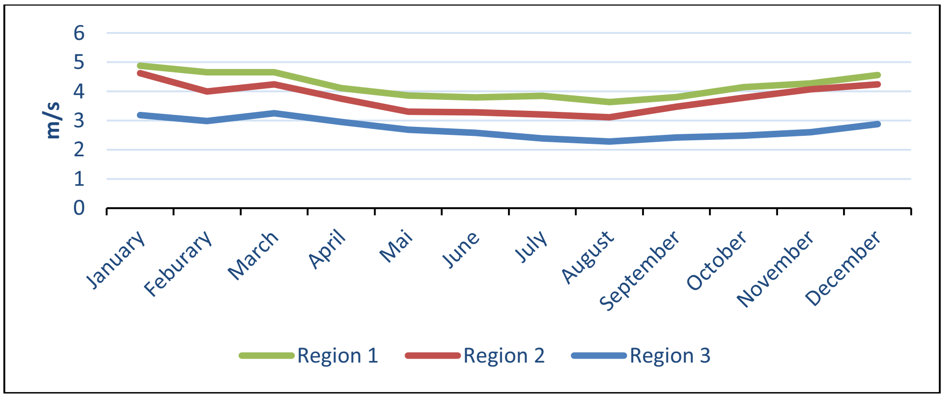

Fig. 5 Average monthly wind speed for different regions in Germany [26].

All locations have been chosen in order to obtain the highest bandwidth of values in each region, thus covering the boundaries. Representative values for all 18 locations, including solar irradiation, wind speed, atmospheric pressure, average annual ground temperature, elevation, and humidity are considered in this work. Within the energy model the electric energy production fed to the grid and the capacity factor at each side is obtained using the meteorological and geographical data from the regions respectively.

3.2.1 PV systems

The yield of PV systems depends, in addition to the site conditions, on the sun's angle on the surface, installed capacity, technology, and occurring losses, as explained in the previous sections. Hence, three different sizes of PV systems are chosen for the estimation in RETScreen, i.e. roof-mounted small system (5 kW_p), roof-mounted large system (200 kW_p) and ground-mounted large system (3000 kW_p) using the different parameters reported in Table 2.

Table 2. Parameters for PV systems [27, 28].

Parameter	Literature	2015	2030

Life span (years)	20 – 30	25	25
Efficiency (mono-SI in %)	Up to 24	15	20
Inclination angle (degree)	30 - 40	35	35
Performance ratio (%)	80 - 90	85	85

3.2.2 Wind

The yield of onshore wind power plants basically depends on the hub height, the rotor diameter, the capacity, the wind speed, losses, and availability of the plant. For the estimation, a theoretical wind turbine is placed at the respective locations. Within, expected annual energy yield, the full-load hours and the average capacity factors are calculated. For the calculations, we use an Enercon E101 turbine, since this is a well-established model for low wind speed conditions in Germany. The data for the wind turbine assumed for the RETScreen model calculations is shown in Table 3.

Table 3. Parameters for the onshore wind power system [29, 30].

Parameter	2015	2030
Turbine capacity (MW)	3	3
Hub height (m)	110	130
Rotor diameter (m)	101	101
Availability (%)	98	98
Losses (%)	10	10
Windshear exponent	0.19	0.19

3.2.3 Carbon analysis

The model calculates the annual GHG emission reductions for a clean energy project compared to a base case system. RETScreen has the necessary parameters already implemented. The baseline uses historical emission factors of fossil-fueled power plants in Germany. The base case electricity system is estimated by inputs of the electricity sources mix by fuel type and baseline transmission and distribution (T&D) grid losses, respectively. The T&D losses are reported to be 2-8% [24]. RETScreen's default emission factor for the base case systems is used in the analysis (Table 4). The base case system contains the whole German energy supply system, including all relevant fossil-fueled power generation technologies.

Table 4 Emission factor for energy supply in Germany [24].

Type	Combined system
GHG [tCO_2/MWh]	0.501

RETScreen compares this baseline GHG emission case with the proposed new electricity system. The PV system and the wind-turbine do not emit GHG in this model. It is now important to note that the full life-cycle analysis does have GHG emissions from transportation, resource extraction, manufacturing, and more. However, the estimations in the model do not account for full life cycle emissions of any of the conventional electricity supply, so the PV life cycle emissions are also omitted.

3.2.4 Financial analysis

RETScreen requires several assumptions for the initial and annual cost of PV systems and onshore wind, shown in Table 5. Initial costs are given in terms of minimum and maximum price ranges for 2015 and 2030.

Table 5 Initial and annual costs for PV and wind [25, 31, 32].

Initial costs 2015 [€/kW]	Roof-mounted small PV	Roof-mounted large PV	Ground-mounted PV	Onshore wind
Min	1300	1000	1000	1000
Max	1800	1700	1400	1800
2030 [€/kW]				
Min	800	570	570	950
Max	1000	950	800	1700
Annual costs	[€/kWp]	[€/kWp]	[€/kWp]	[€/kWh]
2015	35	35	35	0.018
2030	35	35	35	0.018

RETScreen requires assumptions for the debt ratio, the debt interest rate, the debt term, the inflation rate, and the discount rate. They differ depending on technology, plant size, and location. Hence, low project-specific risks and low requirements regarding the return of investment lead to low discount rates. A discount rate of 4.4% is assumed for small roof-mounted PV systems, 4.8% for large roof-mounted and open-grounded PV systems, and 5.9% for onshore wind energy systems. For solar PV, a debt interest rate of 4% is assumed, while for onshore wind the assumed value is 4.4%. Moreover, for solar PV, a debt ratio of 80% is assumed, for onshore wind it is 70%. The inflation rate is assumed to be 2%. Table 6 provides a summary of the general assumptions made for the RETScreen calculations.

Table 6 Parameters for the financial analysis in RETScreen [12, 33].

Parameters	Roof-mounted small PV	Roof-mounted large PV	Ground-mounted PV	Onshore wind
Debt ratio (%)	80	80	80	70
Debt interest rate (%)	4	4	4	4.5
Debt term (year)	20	20	20	20
Inflation rate (%)	2	2	2	2
Discount rate (%)	4.4	4.8	4.8	5.9
Lifespan (year)	25	25	25	20

4 RESULTS AND DISCUSSION

After taking into account all assumptions and parameters mentioned in the previous section, the RETScreen model is run. The results include PV system and onshore wind energy yield, as well as the GHG emission reduction potentials by RET, the LCOE, the GHG emission mitigation costs, and a sensitivity analysis for different regions in Germany. The sensitivity analysis also includes the respective capacity, electricity generation, and the mitigated GHG emissions. Note that PV systems only differ in their capacity, size, cost, and finance structure, whereas the technology, inclination of the sun, losses and site conditions are the same. Therefore, the yields of the PV systems are identical for the respective regions. The values are to be understood as the yearly average net values for PV systems over twenty-five years, and onshore wind over twenty years of operation.

4.1 Capacity

The average installed capacity for PV systems and onshore wind power plants for 2015 and 2030 is shown in Fig. 6. It shows that wind has a significantly higher capacity than PV systems in regions two and three. PV systems have the highest capacity in the south (13.15%) and the lowest in the north (10.9%). Conversely, wind has the highest capacity in the north (30.5%) and lowest in the south (11.5%). According to Fig. 6, the installed capacities are generally higher in 2030 than in 2015. PV systems have, on average, a 5.5% higher capacity in 2030, as compared to 2015. The capacity of onshore wind increases about 6.14% on average from 2015 - 2030.

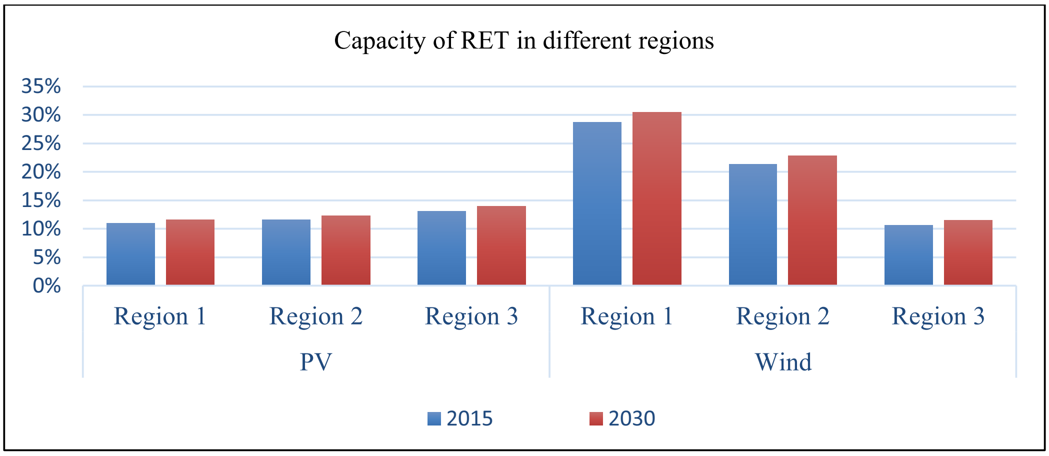

Fig. 6 Shares of RET capacity in different regions of Germany, 2015 vs. 2030.

4.2 Electricity generation

The average yearly electricity generation of RET in MWh per MW and year of installed capacity is shown in Fig. 7. Electricity generation of PV systems is significantly higher in region three (1.15 MWh/MW) than in region one (0.96 MWh/MW). In turn, electricity generation of onshore wind power plants has the highest values in region one (2.67 MWh/MW) and decreases to region three (0.93 MWh/MW). The electricity generation in 2030 is higher than in 2015. PV systems have an average 5.5% higher electricity generation in 2030 compared to 2015, while onshore wind increases by about 6.14% on average.

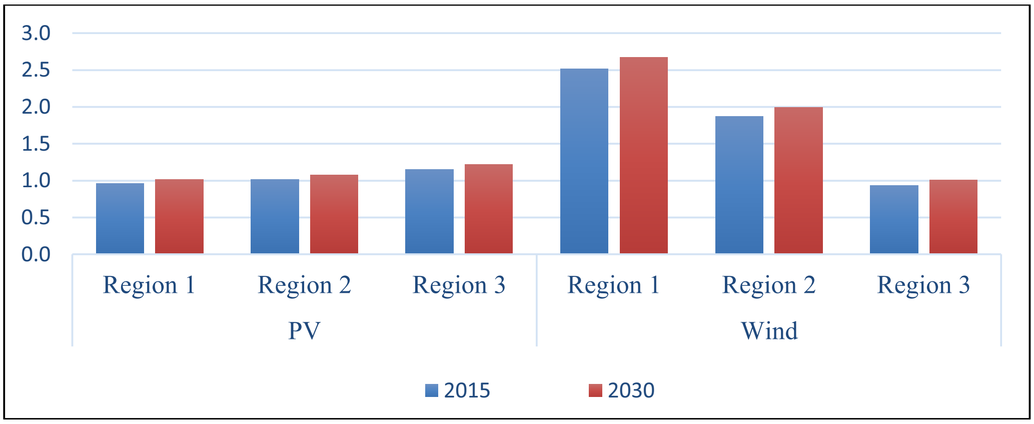

Fig. 7. Electricity generation by RETs installed in different regions (MWh/MW/year), 2015 vs. 2030.

4.3 Carbon analysis

The RETScreen model also allows to calculate the reduction of GHG emissions as a result of using wind and solar PV as electricity generation sources. The resulting GHG emission mitigation per MWa of the respective RET for all regions in 2015 and 2030 are presented in Fig. 8 (the unit t CO_2/MWa denotes that one MW of installed capacity of a respective RET reduces CO_2 emissions by a specific amount per year).

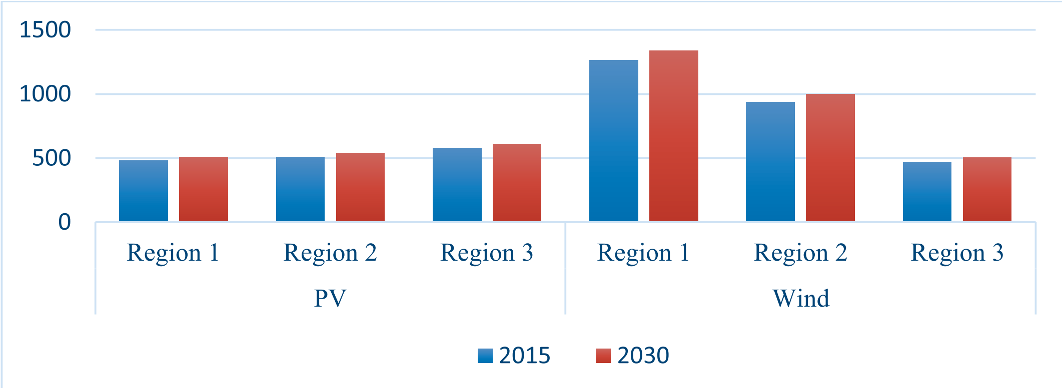

Fig. 8. Specific emission mitigation by means of RETs installed in different regions (in t CO_2/MWa), 2015 vs. 2030.

For 2015, wind energy has the highest GHG mitigation potential in region one (1300 t CO_2/MWa). The lowest potential contain PV-systems in region one and wind energy in region three (500 t CO_2/MWa). A PV system installed in region three has an 18% higher GHG mitigation potential than in region one. In contrary, wind energy in region three has a 277% lower GHG mitigation potential than in region one. In 2030, GHG potentials of all regions increase by 5.9% on average.
In terms of the projects analyzed, this means that a 3 MW wind turbine would mitigate on average 3789 t CO_2 per year in region one, and 1404 t CO_2 in region three. A fictitious 3 MW open-grounded PV system, in contrast, would reduce GHG emissions on average by 1731 t CO_2 per year in region three, and by 1441 t CO_2 per year in region one for 2015. In 2030, the GHG reduction potential for a theoretical 3 MW wind turbine would increase on average by up to 4016 t CO_2 in region one, and by 1515 t CO_2 in region three. Finally, a fictitious 3 MW open-grounded PV system would help to mitigate on average 1833 t CO_2 in region three, and 1617 t CO_2 in region one.

4.4 Financial analysis: LCOE

In this section, the results of LCOE in 2015 and 2030 are presented for PV-System types and Onshore wind power plants.

4.4.1 Small roof-mounted PV systems

Fig. 9 shows the LCOE for small roof-mounted PV-systems in different regions in Germany for 2015 and 2030. For 2015, the highest values appear for region one with 13.4 -16.8 €-ct/kWh, and the lowest in region three with 11.2 - 14.0 €-ct/kWh. The LCOE in region one is on average 2.5 €-cents higher than in region three.

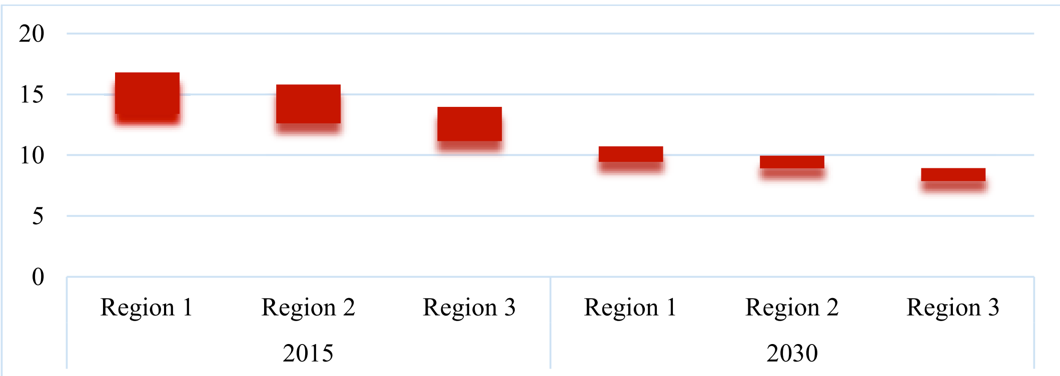

Fig. 9. LCOE of Small roof-mounted PV systems in different regions in ct/kWh, 2015 vs. 2030.

The LCOE decreases significantly in 2030. Thus, the LCOE of region one in 2030 is on average 5 €-ct lower than in 2015. The LCOE in 2030 is below 11 €-ct/kWh for all regions. Region three has the lowest LCOE values (7.9

- 8.9 €-ct/kWh), while region one has the highest ones (9.4 - 10.7 €-ct/kWh). In 2030, the LCOE in region three are, on average, 1.7 €-cents lower than in region one, and 1.0 €-cents lower than in region two.

4.4.2 Large roof-mounted PV-systems

Fig. 10 shows the LCOE for large roof-mounted PV systems in different regions in Germany for 2015 and 2030. For 2015, the highest values appear for region one with 11.4 - 16.2 €-ct/kWh, and the lowest in region three with 9.5 - 13.5 €-ct/kWh. The LCOE of region one in 2015 are on average 2.3 €-cents higher than in region three.

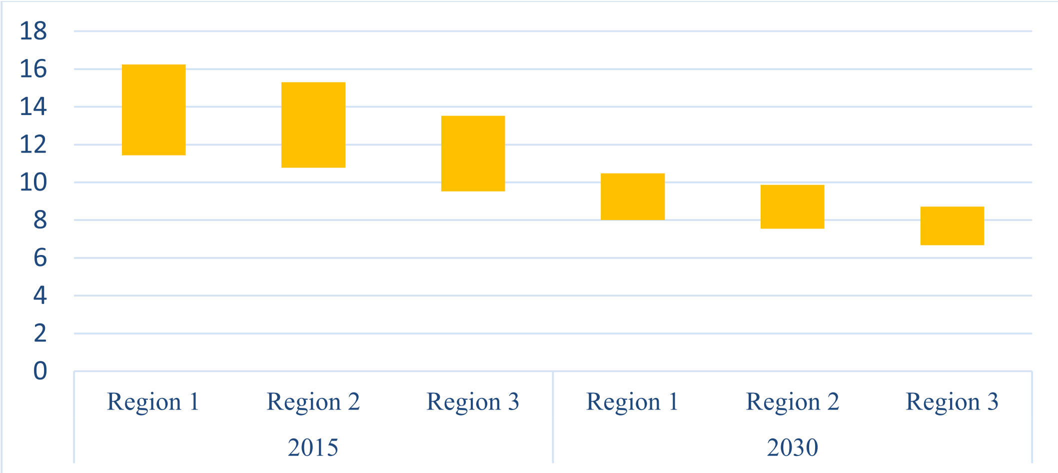

Fig. 10 LCOE of large roof-mounted PV systems in different regions in ct/kWh, 2015 vs. 2030.

The LCOE of large roof-mounted PV systems decreases significantly in 2030. The LCOE is below 11 €-ct/kWh in all regions. In 2030, the lowest LCOE are found for region three with 6.6 - 8.7 €-ct/kWh, and the highest in region one with 8.0 - 10.5 €-ct/kWh. The LCOE of region one in 2030 is, on average, 1.5 €-cents higher than in region three. The LCOE of region one in 2030 is on average 4.6 €-cents lower than in 2015.

4.4.3 Ground-mounted PV systems

Fig. 11 shows the LCOE for open-grounded PV systems in different regions in Germany for 2015 and 2030. For 2015, the highest values appear for region one with 11.4 - 14.2 ct/kWh, and the lowest in region three with 9.5 - 11.8 €-ct/kWh. The LCOE of region one in 2015 is, on average, 2.1 €-cents higher than for region three.

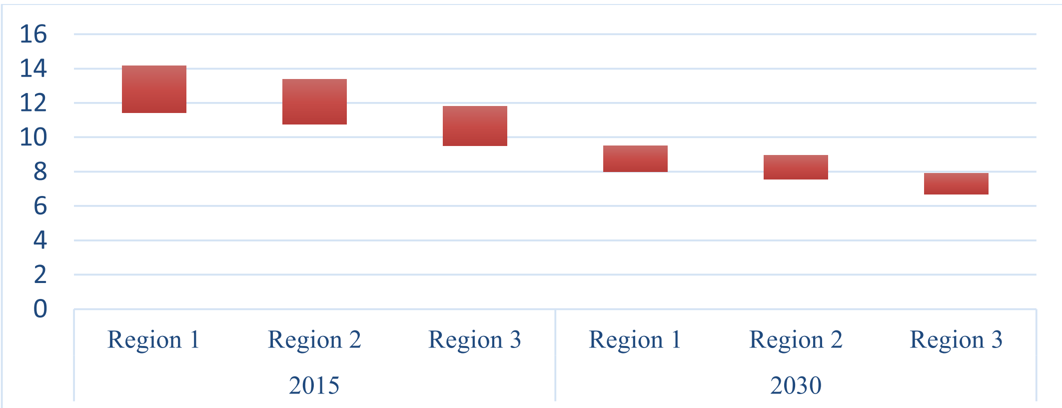

Fig.11 LCOE of Ground-Mounted PV-Systems in different regions in ct/kWh.

The LCOE of ground-mounted PV systems decreases significantly in 2030. Thus, the LCOE of region one is on average 4.1 €-cents lower than in 2015. Region three has the lowest LCOE in 2030 with 6.7 - 7.9 €-ct/kWh, while region one has the highest LCOE with 8.0 - 9.5 €-ct/kWh. Note that all values in 2030 are below by 10 €-ct/kWh. The LCOE in 2030 in region one is on average 1.5 €-ct higher than in region three.

4.4.4 Onshore wind power plants

Fig. 12 shows the LCOE of onshore wind in 2015 and 2030 for different regions in Germany. For 2015, LCOE of onshore wind is between 5.9 - 7.9 €-ct/kWh in region one and almost 7.1 - 18 €-ct/kWh in region three. The LCOE in region three are, on average, 7.8 €-cents higher than in region one. The LCOE of region two is on average 2.0 €-cents higher than in region one.

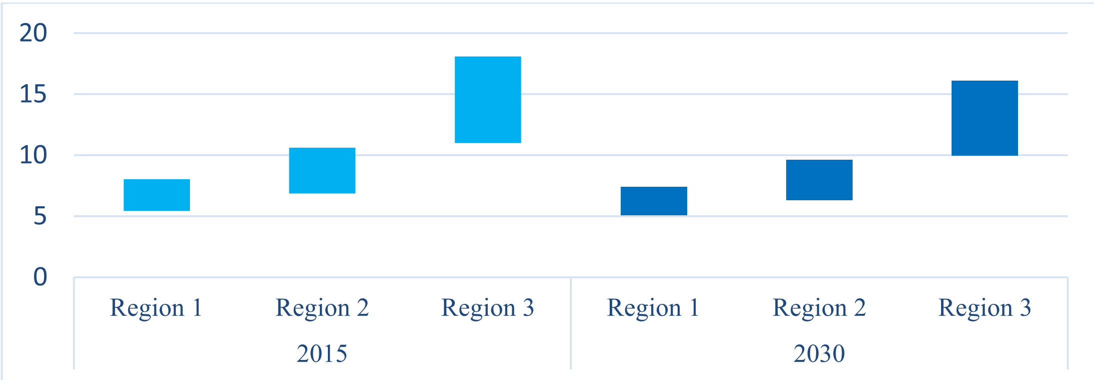

Fig. 12 LCOE of Onshore wind in different regions in ct/kWh, 2015 vs. 2030.

The LCOE of onshore wind energy in Germany decreases modestly in 2030. Thus, the LCOE of region one is on average 0.5 €-cents lower than in 2015. Region three has the highest LCOE in 2030 with 9.9 - 16.1 €-ct/kWh, while region one has the lowest with 5.1 - 7.4 €-ct/kWh. The values of regions one and two in 2030 are both below 10 €-ct/kWh. The LCOE in 2030 in region three is on average 6.8 €-cents higher than in region one, and 1.8 €-cents higher than for region two.

4.5 **GHG reduction costs (GRC)**

In this section, results for GHG reduction costs for RET in different regions for 2015 and 2030 are presented. Herein, the results are given in ranges, as explained in the methodology section. It represents the cost to avoid the emission of one ton of CO_2 emitted by the average German electricity production system.

4.5.1 Small roof-mounted PV systems

Fig. 13 shows the GHG reduction costs for small roof-mounted PV systems in different regions in Germany for 2015 and 2030. In 2015, GRC ranges between 222 -334 €/t CO_2 in region three and region one respectively. Region three has in average 50 €/t CO_2 lower GRC than region one. Region two has on average 33 €/t CO_2 lower GRC than region one.
The GHG reduction cost decrease significantly in 2030. The GRC in region three is on average 84 €/t CO_2 lower in 2030 than in 2015. The minimum is 156 €/t CO_2 and the maximum 214 €/t CO_2.

4.5.2 Large roof-mounted PV systems

Fig. 14 shows the GHG reduction costs for large PV roof-mounted systems in different regions in Germany for 2015 and 2030. In 2015, GRC range between 190-324 €/t CO_2 in region three and region one, respectively.
Region three has on average lower GRC of 46 €/t CO_2 than region one, and on average lower GRC of 30 €/t CO_2 than region two. The GHG reduction costs decrease significantly in 2030. The GRC in region three are on average 76 €/t CO_2 lower in 2030 than in 2015. The minimum value is 133 €/t CO_2 and the maximum 209 €/t CO_2.

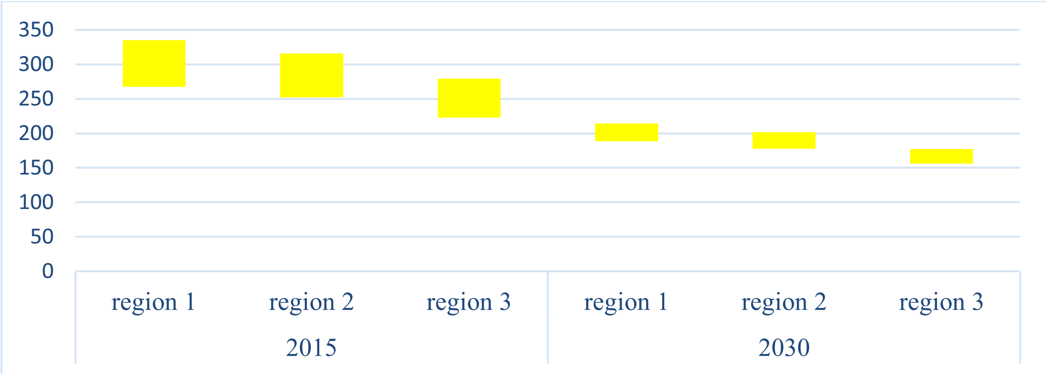

Fig. 13 Range of GRC for a small roof-mounted PV system in different regions, 2015 vs. 2030.

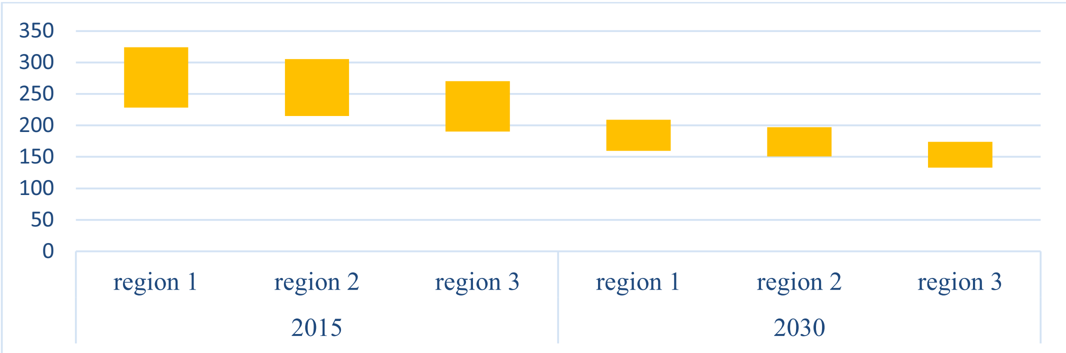

Fig.14 Range of GRC for Large, roof-mounted PV systems in different regions, 2015 vs. 2030.

4.5.3 Open-grounded PV-Systems

Fig. 15 shows the GHG reduction costs for open-grounded PV systems in different regions in Germany for 2015 and 2030. In 2015, the GRC range between 190-283 €/t CO_2 in region three and region one, respectively. Region three has on average 42 €/t CO_2 lower GRC than region one, and on average a lower GRC of 28 €/t CO_2 than region two. Note also that the GHG reduction costs decrease significantly in 2030. The GRC in region three are on average 67 €/t CO_2 lower in 2030 than in 2015; the minimum is 133 €/t CO_2 and the maximum 289 €/t CO_2.

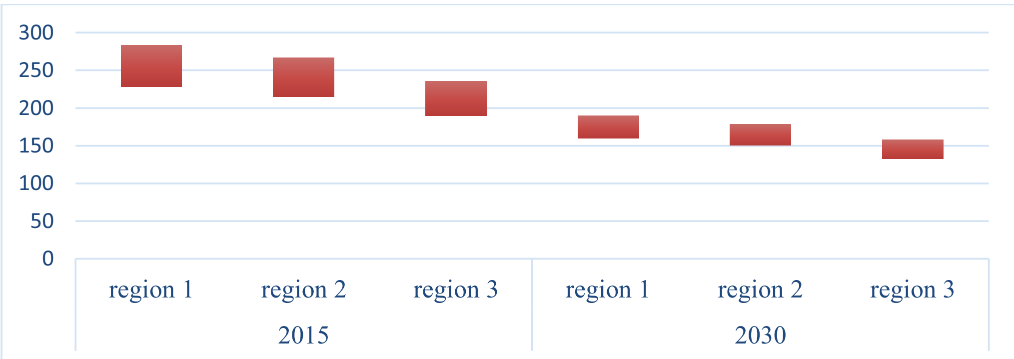

Fig.15 Range of GRC for Open-grounded PV systems in different regions, 2015 vs. 2030.

4.5.4 Onshore wind power plants

Fig. 16 shows the GHG reduction costs for onshore wind energy in different regions in Germany for 2015 and 2030. In 2015, the GRC ranges between 108 - 360 €/t CO_2 in region three and region one, respectively. Region one has, on average, a lower GRC of 156 €/t CO_2 than region three, and on average a lower GRC of 40 €/t CO_2 than region two.

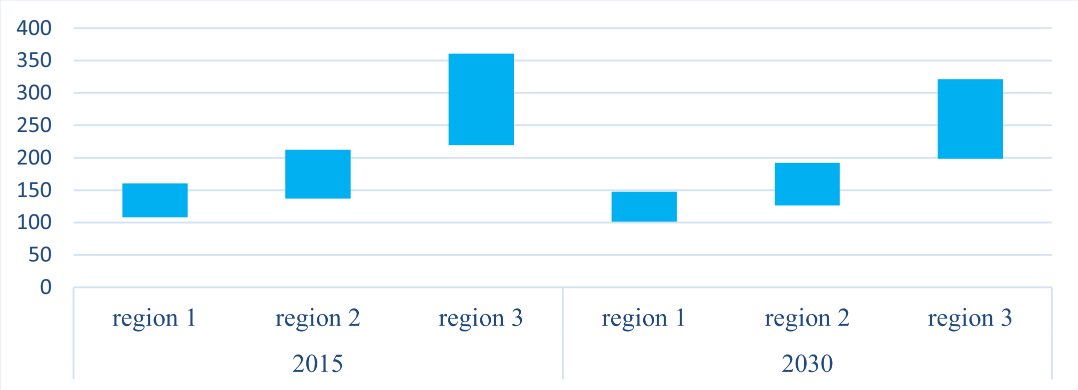

Fig.16 Range of GRC for Onshore Wind in different regions.

The GHG reduction costs slightly decrease in 2030 (in region three they are on average 10 €/t CO_2 lower in 2030 compared to the 2015 value; the minimum is 101 €/tCO_2 and the maximum 321 €/t CO_2).

4.6 Sensitivity analysis

This section describes the results of the sensitivity analysis. The parameters considered are initial and annual costs, debt ratio, discount rate, and debt interest rate.

4.6.1 PV system

Fig. 17 shows the impact of variations of the key parameter values on the LCOE. The sensitivity analysis is done for a small roof-mounted PV system. Heidelberg was chosen as location with a yearly average solar irradiation value of 1150 kWh/ (m^2a). Initial costs of 1500 €/kW_p were used. A deviation in initial costs causes a very large change in the LCOE, followed by the annual costs. In contrast, discount rate, debt rate, and debt ratio all have only a low impact on the LCOE.

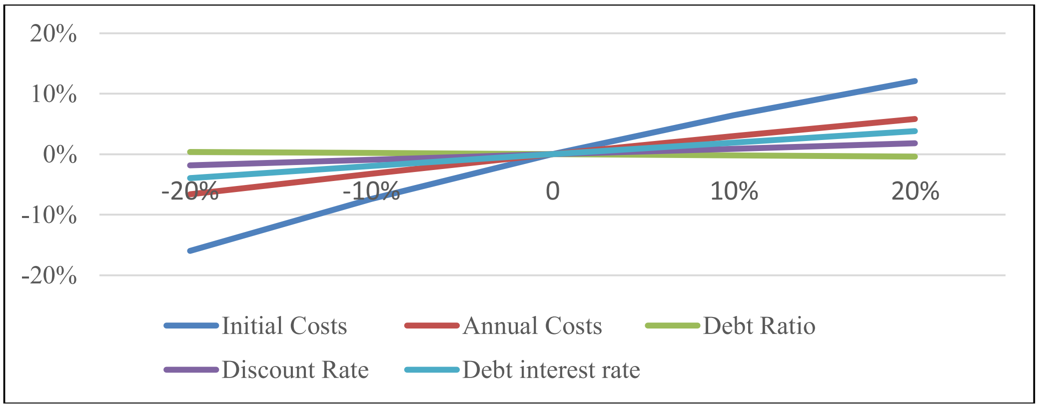

Fig.17 Sensitivity analysis for small roof-mounted PV systems (location: Heidelberg).

4.6.2 Onshore wind

Fig. 18 shows the impact of varying key parameter values on the LCOE of onshore wind energy. The sensitivity analysis shown was computed for the location of Chemnitz, assuming an average annual wind speed of 4.2 m/s and 1400 €/kW of up-front investment costs. The largest impact on the LCOE of onshore wind comes from the initial investment costs. In contrast, financial parameters are found to have a comparatively little effect on LCOE.

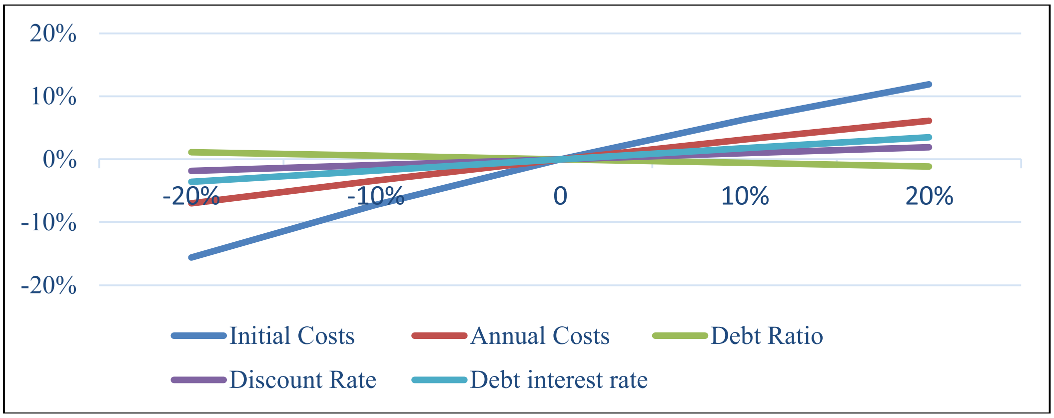

Fig.18 Sensitivity analysis for onshore wind (location: Chemnitz).

4.7 Analysis of results

The LCOE and GRC vary regarding the technology and the specific site conditions. They decrease from 2015 to 2030 due to the technology enhancements and a drop of their system prices. Generally, the site conditions for wind are more favorable in region one than in regions two and three. This leads to comparably higher wind yields and larger GHG reduction potentials in region one. The site conditions for PV systems are, contrary to onshore wind, most suitable in region three, followed by regions two and one. For that reason, the solar yield and GHG reduction potentials for PV systems are greatest in region three. Capacity and net electricity generation are increasing for both technologies from 2015 to 2030. This is due to higher efficiency of PV systems and larger hub heights of onshore wind power plants. Wind energy has a comparably higher yield than solar PV. Electricity generated by onshore wind power plants in region one is more than twice as large as the maximum of electricity generation by PV systems. The same applies to GHG emission reduction. Therefore, the site conditions for onshore wind in region one and two offer the best environment from the point of view of techno-economic feasibility and GHG reduction, followed by the site conditions for PV systems in regions two and three.

In 2015, onshore wind energy in region one possesses the lowest estimated LCOE with 5.4-8.0 €-ct/kWh, followed by PV systems in region three with LCOE of 9.5-14.0 €-ct/kWh. The highest LCOE is found for onshore wind energy in region three with 11.0-18.1 €-ct/kWh. Large open-grounded PV systems have the lowest LCOE, small roof-mounted PV systems the highest amongst the PV systems considered. The GRC vary, depending on technology and site conditions, between 108 and 360 €/t CO_2. Onshore wind energy in region one appears to have the lowest GRC with 108-160 €/t CO_2, while the highest occur in region three with 220-360 €/t CO_2. Open-grounded PV systems feature the lowest GRC of all PV systems investigated, with values ranging from 190 - 235 €/t CO_2 in region three.

In 2030, onshore wind energy in region one appears to have the lowest LCOE with 5.1-7.4 €-ct/kWh. Due to higher learning rates, PV systems are about to close the gap. In each region, the LCOE of PV systems are below 11 €-ct/kWh. The LCOE of region one is on average 5 €-cents lower in 2030 than in 2015. Large open-grounded PV systems have the lowest LCOE. Nevertheless, small roof-mounted PV systems are becoming increasingly competitive. Onshore wind energy has the lowest GHG reduction costs in region one. Small roof-mounted PV systems have the largest potential. The GRC in region three of small roof-mounted PV systems are on average 84 €/t CO_2 lower in 2030 than in 2015. This is a 9.5 % decrease compared to large roof-mounted PV systems and a 20% decrease compared to open-grounded PV systems.

The sensitivity analysis for small roof-mounted PV systems in Germany shows the strong dependence of the LCOE on the initial costs. This explains the sharp drop of LCOE during the last years due to the drop of module prices. The sensitivity analysis undertaken for onshore wind energy shows similar results. However, the learning rate of wind is comparatively low. Therefore, system prices do not show such a high drop as it is found for PV systems module prices.

The estimated values for LCOE of onshore wind energy in 2015 and 2030 matches with the presented results of other studies. The results of roof-mounted PV systems are on average 0.8 €-cent higher. The calculated values of open-grounded PV systems are 2.5 €-cents above the average results of the presented studies. The reasons for these differences are different assumptions made for the energy model, such as module efficiency, sun tracking systems, system size, and meteorological assumptions.

5 CONCLUSIONS

In general, our study shows that it is possible to achieve the ambitious goals of Germany's *Energiewende*. Decreasing electricity production costs of renewable energy technologies, as well as the rising costs of fossil-fueled power plants strengthen the competitiveness of RETs. In the long term, this will reduce the costs for Germany's electricity generation system and help to avoid large amounts of greenhouse gases emissions. In order to shed some new light on this transition process, the LCOE and GRC have been estimated for different regions in Germany for current and prospective technologies, also taking into account their system prices. The expected yield, capacity, and GHG mitigation potential for small- and large-scale roof-mounted and ground-mounted PV systems and for onshore wind power plants have been calculated for different locations. Furthermore, the levelized costs of electricity and the GHG reduction costs have been assessed, And the LCOE has been reviewed in terms of their sensitivity regarding to changes in the values of various key parameters.

The results show that electricity generation costs of wind turbines will decrease only slightly in the future. The capacity will increase through technical improvements and result in higher GHG reduction potentials. The future greenhouse gas emission reduction costs of the RETs studied are found to range from 101-321 €/kWh. The electricity generation costs of PV systems will fall significantly in the future. The decline in prices of PV systems will make them competitive against fossil-fuel-based power generation systems in the not-too-distant future, even in the absence of subsidies. Specifically, in 2030, the LCOE of PV falls below 11 €-ct/kWh. The future GHG emission reduction costs for PV range between 133 and 289 €/t CO_2. Roof-mounted systems are found to have the greatest cost reduction potential, with an average decrease of 84 €/t CO_2 lower in 2030 compared to 2015.

In the future, primarily the site conditions will determine whether or not wind power plants are more cost-effective than PV systems. In northern Germany, wind power has significantly higher yields and, therefore, lower GHG emission mitigation costs. Open-grounded PV systems have the lowest LCOE and GHG reduction costs among PV systems. However, roof-mounted systems become more important due to their high expansion and GHG reduction potentials. The yield of the PV systems considered does not vary much for the different regions compared to onshore wind. Based on the results from our study, we find that it is possible to restructure the German energy generation system both cost-effectively and environmentally efficient. Solar PV and wind energy are already or becoming cost-competitive vis-à-vis fossil electricity generation sources due to decreasing investment costs and increasing capacity. However, further research must be undertaken in order to optimize the integration of wind and solar PV into the electric grid. This includes the economic analysis of grid expansion, storage systems, as well as fossil-fueled power plants with enhanced flexibility.

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Real Option Model for Investment in Hydrogen Tri-generation in Wastewater Treatment Plants under Uncertainties

Kaveh Gharieh[1], Mohsen A.Jafari[2]

[1] *Rutgers University, 96 Frelinghuysen Road, Piscataway, New Jersey, U.S.A, kaveh.gharieh@gmail.com*

2 Rutgers University, 96 Frelinghuysen Road, Piscataway, New Jersey, U.S.A, jafari@rci.rutgers.edu

ABSTRACT

In this article, we present a compound real option model for optimal investment in hydrogen tri-generation and onsite hydrogen dispensing system for a wastewater treatment plant under price and market uncertainties. We formulate the problem as a two stage compound real option. The first option includes investment in hydrogen tri-generation under capital cost and natural gas price uncertainties. The expansion option considers addition of onsite hydrogen dispensing system to the facility which provides additional source of revenue. Investing in the expansion phase is under hydrogen price and expansion capital cost uncertainties. The objective is to find the optimal timing of initial and expansion investments such that savings are maximized. The model is also validated using a set of sensitivity experiments. The sensitivity analysis results are in line with general rule of the real option evaluation that delay in exercising the investment options become more significant as the volatility increases.

KEYWORDS: Investment, Real Option, Micro-grid, Tri-generation

1 INTRODUCTION

Wastewater treatment plants are necessarily located close to the waterfront to discharge the treated wastewater and also more efficient sludge handling. This waterfront dependency increases the likelihood of being affected and damaged during extreme weather conditions. It is no secret that during the super storm Sandy, many wastewater treatment plants were shut down for several days due to power failure, creating major safety problems for the surrounding communities [1]. Along with high risk of failure during extreme weather conditions other factors such as need for reliable power supply for continues operation and generation of considerable amount of energy through treatment processes especially anaerobic digestion are the main motivations to consider wastewater treatment plants for energy resiliency. Recently introduced

hydrogen tri-generation technology, which can be fed by a mixture of facility's waste products and natural gas and produces heat, power and hydrogen can significantly enhance the resiliency of wastewater treatment plants and provide additional sources of revenue [2]. Additional profit could be achieved through onsite hydrogen dispensing for local hydrogen vehicles use. Therefore, hydrogen tri-generation might also be the solution to overcome the challenge of the initial investment cost of the hydrogen early infrastructure deployment [3], [4], [5].
Given the aforementioned distributed energy generation asset, this article develops tools and models that can be used to optimally plan for investment to move towards energy resiliency and revenue generation in wastewater treatment facilities. The particular problem addressed in this paper is to define the optimal investment timing and thresholds to invest in hydrogen tri-generation system and onsite hydrogen dispensing system. The model enforces hedging mechanisms for risks against existing market and price uncertainties, under optimally planned operation of assets.

Currently, US Department of Energy (DOE) is carrying out several researches on financial benefits of deploying tri-generation in large scale facilities other than wastewater treatment plants such as hotels and university campuses. A released report of this study includes spread sheet software to deterministically calculate the Net Present Value of deploying tri-generation to supply heat and power demands of energy intensive sectors along with hydrogen demand of the local hydrogen vehicles [6]. Their model does not account for any type of short-term volatilities or long-term uncertainties. In this work, we decompose the similar investment problem and formulate it as a two stage risk based investment plan and solve for optimal timing of each investment stage using compound real option approach by which you can account for uncertainties. The first stage investment aims at self-sustainability and power resiliency of the wastewater treatment facility; however the objective of the subsequent expansion investment is to create additional revenue stream via onsite hydrogen dispensing for transportation or other applications. The first option includes investment in Molten Carbonate Fuel Cell (MCFC) which is the most common hydrogen tri-generation system without utilizing hydrogen by-product in a downstream operation. Once the initial investment option is exercised, the produced hydrogen will be transported to the demand point by truck and sold at a wholesale market price. Hydrogen delivery cost is the fuel and labor cost of driving to and from the station [7]. The second option (expansion option) includes investment on an onsite hydrogen refueling station, which uses hydrogen by-product of the plant to generate additional revenue. In this stage, compression, storage and dispensing hardware is added to the facility, by which the produced hydrogen will be sold onsite. Hydrogen is sold at retail price, which is much higher than wholesale price.

The initial and expansion options exercise date are dependent on the behavior of a number of stochastic variables and investment options are exercised once the stochastic variables are most favorable to the investor. Initial investment option exercise is assumed to be dependent on two stochastic variables:

(X1: Gas Price, X2: MCFC technology cost)

Expansion investment option exercise time depends on two stochastic variables:

(X1': Hydrogen Price, X2': Expansion capital cost)

Hydrogen price and natural gas price are factors which drive the operational dynamics. Formulating the problem as a compound real option, we are particularly interested in the perpetual American option with exchange a bundle of n stochastic costs against a bundle of m assets in both initial and expansion options. The right time to exercise the so called option is classified as an (n, m) exchange problem [8]. The (1,1) exchange model also referred as "the price and cost uncertainty" was initially developed by McDonald and Siegel [9]. Using the same notation, our initial investment problem is an extended (1,1) exchange problem, where we seek to determine the right time to exercise the investment option with one stochastic cost (i.e. MCFC capital cost in our case) and one stochastic project value (i.e. operational savings of micro-grid in our case). Note that the value of the project is driven by the price of natural gas, thus it is stochastic. The expansion problem is also an (1,1) exchange where we seek to determine the right time to exercise the expansion option with one stochastic cost (i.e. Expansion capital cost in our case) and one stochastic variable (i.e. Hydrogen price in our case) defining the project value. In the exchange (1,1) problem, the investment trigger is presented by a line in a 2-D space of stochastic variables. The right time to exercise the (1,1) exchange problems are the first time when one hits the trigger line. Details of our solution approach are presented in the following section.

2 SOLUTION APPROACH

For the proposed distributed energy generation asset, the investment payoff is directly linked to the operation of the hydrogen tri-generation system and the return of investment depends on the short-term optimization of the asset. A short term operation optimization framework is developed based on "Fuel Cell Power" spreadsheet model developed by National Renewable Energy Laboratory (NREL) with the objective of daily operational savings maximization. The "Fuel Cell Power" model simulations for tri-generation systems are created using a two-step process. In the first step, thermodynamically correct tri-generation system designs are developed using ASPEN Plus (i.e. optimization software for chemical processes). Then these models are used to develop simplified linear models of system performance. It has been demonstrated that under certain conditions, "Fuel Cell Power" results approximate the ASPEN Plus results [10]. Taking Monte Carlo simulation approach several sample path realizations of hydrogen price and natural gas price over the course of planning horizon are generated. The "Fuel Cell Power" based operation model is used to calculate annual operational savings for each simulated path of natural gas price and hydrogen price over the course of investment horizon for both cases of initial and expansion investments. The calculated initial and expansion operational savings paths along with simulated sample paths of initial and expansion capital costs are used in the long-term investment model which decides when to invest on the assets (Initial and expansion investments). Therefore, the optimal investment timing strategy is determined which maximizes the cumulative cash flow until the life time of the assets. Details of the investment timing model are presented in the following section.

2.1 Optimal Investment Timing Model

The strategy used to evaluate the investment is to decompose the investment problem into a two-staged investment plan. The main reason is existence of several sources of uncertainty and decomposition approach makes it easier to handle risk and uncertainty in investment. Since Net Present Value approach is not capable to handle uncertainty, real option approach adopted from option theory in finance is applied to our problem. Applying the real option paradigm, investment decisions can be treated as the exercising of an option. Formally speaking, "Real option" is the right (option) to undertake certain business initiatives such as contracting an investment, abandoning, expanding and deferring [11]. The main advantage of applying real option approach to investment problems is the opportunity to delay an investment under uncertainty. By postponing the investment more information for better decisions would be revealed [12], [13]. According to the composite structure of the proposed investment strategy, simple real option models are not applicable. The decomposed investment problem can be categorized as a compound real option problem. Compound real options are combination of real options, where an exercise of a real option opens another real option and are mostly used in research and development and also in industrial projects [14]. Real option valuation problems can be solved by both analytical and numerical solutions. Longstaff and Schwartz introduced Least Squares Monte Carlo (LSM) technique to solve the real option problems by simulation [15]. Using this method, at each exercise time, the option holder decides whether to keep the option alive or to immediately exercise the option. The exercise strategy is determined by comparing the immediate payoff from exercising the option and the conditional expectation of payoff from keeping the option alive. The conditional expectation is estimated from the cross sectional information in the simulated paths using least squares regression. To do so, the subsequent realized payoffs from continuation are regressed on the values of state variables. This function is then applied to determine the conditional expectation of continuation at each exercise time. The decision rule to find out the stopping time for a simple real option problem denoted ζ(w) at tn on the w-th simulated path is as follows.

$$If \quad \Theta(t_{n,},X_{t_n}(w)) \leq \Pi\ (t_{n,},X_{t_n}(w)) \quad then \quad \zeta(w) = t_n \qquad \textbf{(1)}$$

where Θ is the continuation value, X is state variable, Π is the payoff of the option and ζ is the stopping time for option. The payoff of the option at each date is calculated by discounting all savings up to the lifetime of the invested assets and netting out the investment cost. The value of the option is the present value of expected cash flow from exercising the option. Gamba [16] presents an extension to the Least Squares Monte Carlo (LSM) approach that enables the model to solve for compound real options. The approach is based on the concept that in the compound real option, the value of the initial claim also depends on the value of the subsequent one. Let there be given 2 compound real options. We assume that the path-wise stopping date for the subsequent option has been already calculated using the method described above. We then compute the stopping time ζ1(w) for initial investment option at tn on the w-th path is as follows.

$$If \quad \Theta_1(t_{n,},X_{t_n}(w)) \leq \Pi_1\ (t_{n,},X_{t_n}(w)) + F_2\ (t_{n,},X_{t_n}(w)) \quad then \quad \zeta_1(w) = t_n \qquad \textbf{(2)}$$

where Θ1 is the continuation value, Π1 is the payoff of the initial option and F2 is the value of the second option and ζ1 is the stopping time for the initial option.
Taking this approach, the expectation of continuation at each exercise time for initial investment in our problem is as follows.

$$E[Continuation_t|\ gp(t\text{-}1),\ MCFC\_Cost(t\text{-}1)] = \beta_{0,t-1} + \beta_{1,t-1}gp(t\text{-}1) + \beta_{2,t-1}\ MCFC\_Cost\ (t\text{-}1) + \beta_{3,t-1}gp(t\text{-}1)^2 + \beta_{4,t-1}\ MCFC\_Cost\ (t\text{-}1)^2 \qquad \textbf{(3)}$$

where *gp* and *MCFC_Cost* , are gas price and MCFC stack capital costs. In addition, the expectation of continuation at each exercise time for expansion investment is as follows.

$$E[Continuation_t|\ h2\_rp(t\text{-}1),\ Exp\_Cost(t\text{-}1)] = \alpha_{0,t-1} + \alpha_{1,t-1}\ h2\_rp\ (t\text{-}1) + \alpha_{2,t-1}\ Exp\_Cost\ (t\text{-}1) + \alpha_{3,t-1}\ h2\_rp\ (t\text{-}1)^2 + \alpha_{4,t-1}\ Exp\_Cost\ (t\text{-}1)^2 \qquad \textbf{(4)}$$

where *h2_rp* and *Exp_Cost* are hydrogen retail price and expansion investment costs respectively.

3 ILLUSTRATIVE EXAMPLE

We assume that natural gas prices follow a Geometric Brownian Motion (GBM). There is no specific stochastic process for hydrogen price, MCFC and expansion capital costs. Since there is no sufficient historical data to estimate a stochastic process for these variables over time, we assume GBM with positive drift for hydrogen prices and with negative drift for MCFC stack and expansion capital costs. Table 1 gives the initial value along with annual drift and volatility of stochastic processes.

Table 1 : Stochastic parameters of GBM processes

	Gas price	**Hydrogen price**	**MCFC stack cost**	**Expansion cost**
Initial value	7 ($/mmBtu)	365 ($/Mwh)	1450000 ($)	561616 ($)
Drift (μ)	0.045	0.045	-0.03	-0.03
Volatility (σ)	0.2	0.01	0.03	0.03

Using the results from the sample paths; probability of exercising the initial investment option in each year ($Pr_{initial}$) over the course of planning horizon (4 years) is calculated and presented in Table 2.

Table 2 : Probabilities of exercising the initial option

	Year 1	**Year 2**	**Year 3**	**Year 4**
$Pr_{initial}$	0.22	0.31	0.47	0

The probability of exercising the expansion option conditional on exercising the initial option in each year is presented in Table 3.

Table 3 : Probabilities of exercising the expansion option

	Year 2	**Year 3**	**Year 4**
Expansion|initial @ 1	0.04	0.19	0.75
Expansion|initial @ 2	0	0.12	0.79
Expansion|initial @ 3	0	0	0.98

In addition, expectations of optimal thresholds for initial option exercise are calculated from conditional distribution function presented in equation (5).

$$E(X^*) = \sum_{i=1}^{4} E(X^* \mid \zeta = 1)\, P(\zeta = i) \qquad \textbf{(5)}$$

where X^* is the threshold value for stochastic variable X in the initial and expansion investments. Table 4 presents the initial investments thresholds.

Table 4 : Initial option trigger thresholds

Investment Stage	Thresholds expectation		
Initial	E[gp*]	($/mmBtu)	7.25
	E[MCFC _Cost *]	($)	1377507.23

Fig. 1 shows the expected thresholds to exercise the expansion option conditional on exercising the initial option.

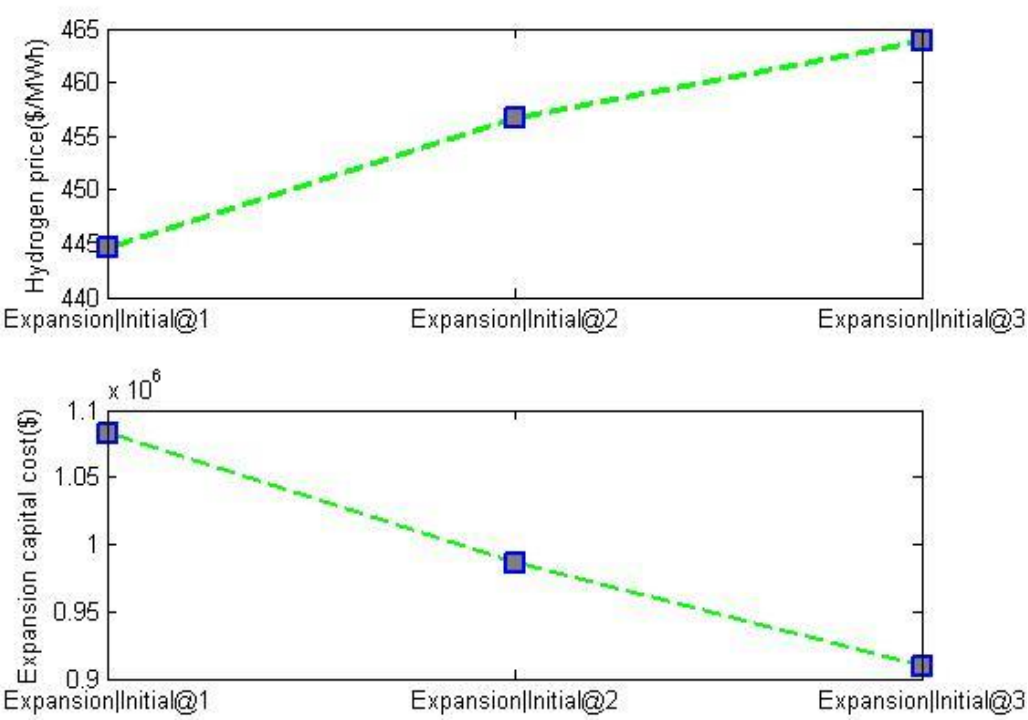


Fig. 1. Expected thresholds to exercise the expansion option

According to decreasing trend of expansion capital cost we can observe that the expansion investment is triggered in lower expansion capital costs in later years. In addition, the hydrogen price thresholds are higher in later years of expansion option exercise according to its increasing trend.

4 SENSITIVITY ANALYSIS

In order to validate our model, we examine the sensitivity of investment decisions to MCFC and expansion capital costs decline rate, MCFC cost volatility and hydrogen price volatility. A general result of the real option evaluation is that higher volatility and uncertainty results in higher value of waiting for more information about the uncertainty. Therefore, higher uncertainty increase the investment thresholds of stochastic variables with increasing trend and decreases the exercise thresholds of stochastic variables with decreasing trend [17].

We start our sensitivity analysis by investigating the effect of MCFC and expansion capital costs decline rate. Our conjecture is to observe delay in investments decisions by increasing the absolute value of the decline rates of both MCFC and expansion capital costs. Fig. 2 represents MCFC cost triggering thresholds for different levels of annual decline rate (i.e. -0.09, -0.07, -0.05 and -0.03).

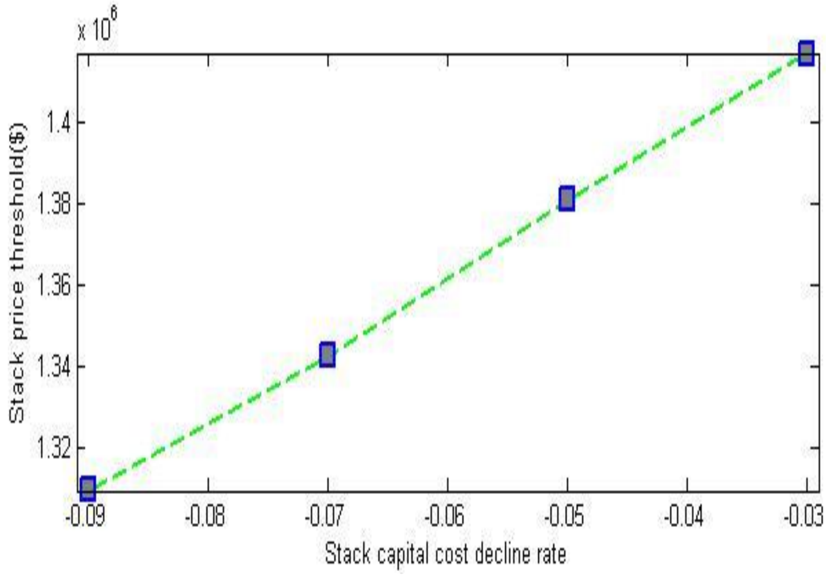


Fig. 2. MCFC cost threshold sensitivity to decline rate

In addition, Fig. 3 shows the expansion costs thresholds conditional on initial investment, for different levels of expansion cost decline rate.

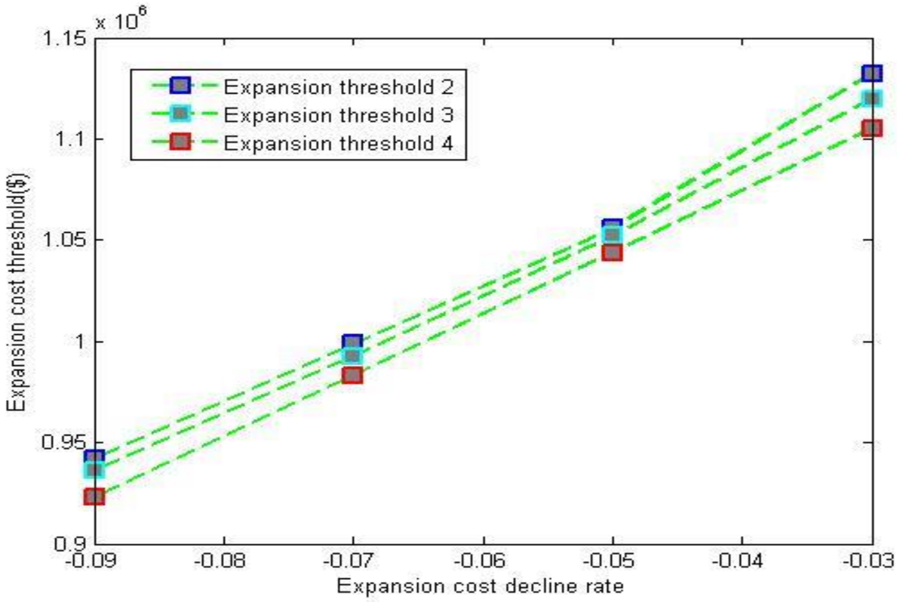


Fig. 3. Expansion cost threshold sensitivity to decline rate

Next, we examine the sensitivity of initial investment timing decision to MCFC cost volatility. Fig. 4 shows how the initial investment decisions are modified for three levels of MCFC stack cost volatility (i.e. 0.01, 0.05 and 0.1).

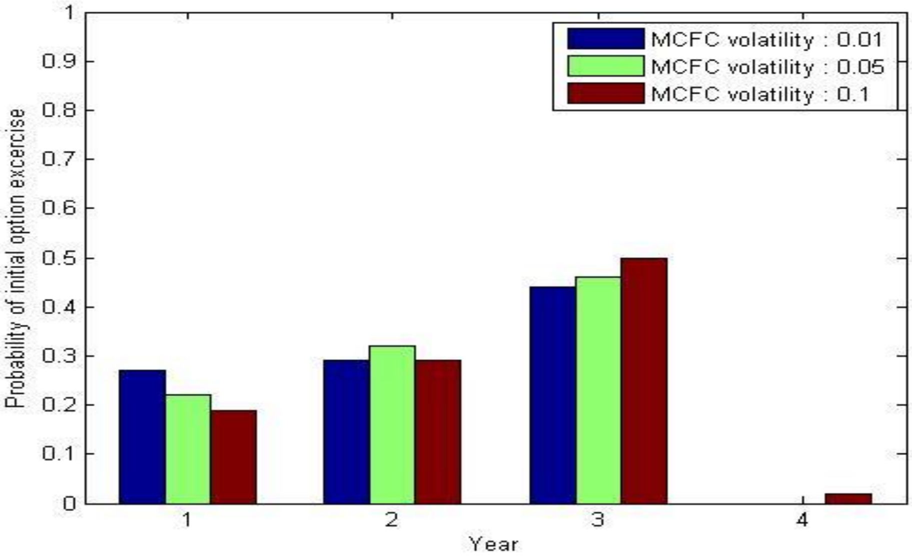
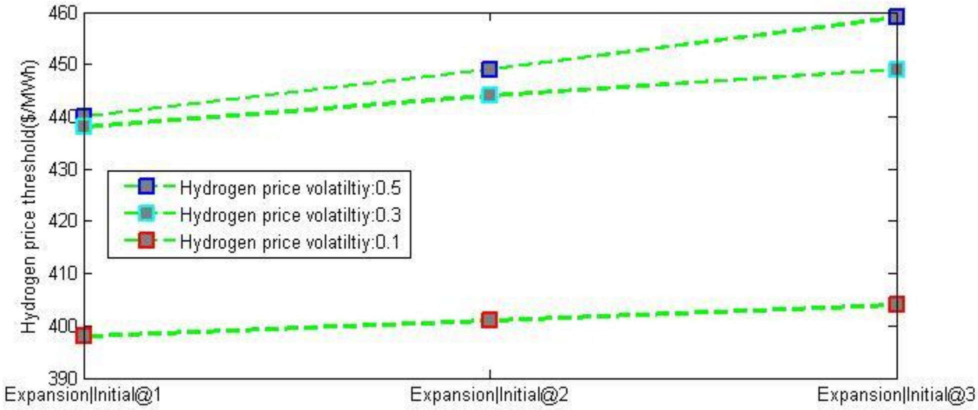


Fig. 4. Initial investment decision sensitivity to MCFC cost volatility

We observe delay in initial option exercise once the volatility of MCFC capital cost increases which is in line with general result of real option that delays the investment decisions in more uncertain environments. We also anticipate that increasing the hydrogen price volatility delays the expansion option exercise time. Delaying the expansion option exercise date, results in higher hydrogen price thresholds and lower expansion capital costs. Fig. 5 shows how hydrogen price volatility impacts the thresholds to exercise the expansion option.



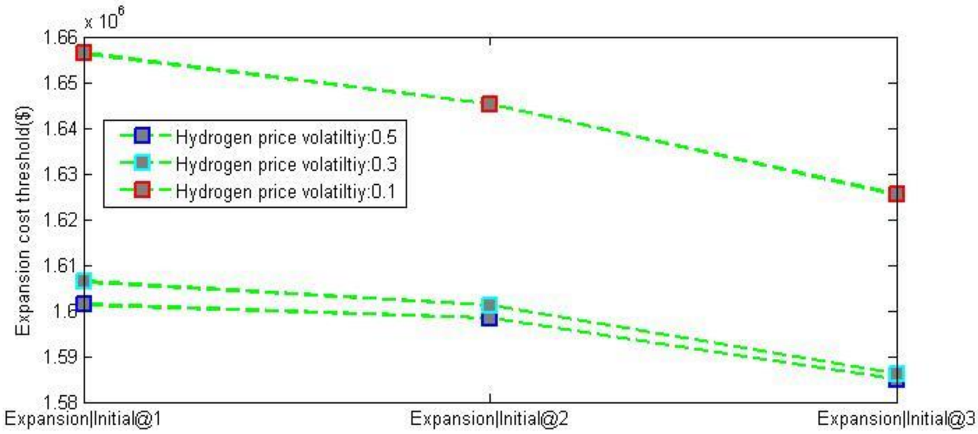


Fig. 5. Expansion investment thresholds sensitivity to hydrogen price volatility

4 CONCLUSION

The work presented in this article, tackles the problem of optimal investment in a two stage investment in hydrogen tri-generation in a wastewater treatment facility and addition of onsite hydrogen dispensing system under several sources of uncertainty. Solving the problem as a compound real option makes it possible to take into account market and price uncertainties. To handle multiple stochastic variables, a simulation based approach with least squares regression is applied. The impact of annual decline rate of capital costs along with volatility of hydrogen price and initial stage capital cost are investigated. The sensitivity analysis results are in line with general result of the real option evaluation that delay in exercising the investment options become more significant as the decline rate and volatility increase.

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The European energy challenge for 2050: Energy security, efficiency and sustainability

Fernando DeLlano-Paz[1], Paulino Martinez Fernández[1], Isabel Soares[2]

[1] Universidade da Coruña, Facultade de Economía e Empresa, Campus de Elviña s/n (15.071) A Coruña, España, fdellano@udc.es
[2] Universidade do Porto, Facultade de Economía, Rua Doutor Roberto Frias, Porto, Portugal, isoares@fep.up.pt

ABSTRACT

The resolution of the energy problem contemplates the conciliation of three key elements: energy security, sustainability and competitiveness. The high degree of energy dependence of the economies forces them to import energy resources from other countries or regions. Each State looks for mitigating its energies portfolio risks -in origin and destination- through the diversification of its Energy mix, avoiding an unwished energy supply disruption. The balance of four properties is in play: capacity, accessibility, affordability and acceptability. In this context the implementation of renewable energy sources (RES) permitted reducing energy dependence in the European Union due to its principal features: autochthonous and boundless -with some restrictions by type of energy-.

In this study we review the diversification definition and the different indexes proposed in the literature as well as we suggest an optimization model based on Modern Portfolio Theory. This methodology has had wide acceptance in energy planning. Through this approach we propose a complete model which considers together with: efficiency –IEA Efficiency index-, risk –portfolio theory approach-, diversification - Herfindahl-Hirschmann index- and sustainability -Pollutant emissions reduction goal-. We apply this model to the European Union, considering 2050 Horizon. We include different nuclear energy shutting down scenarios (50% and elimination) for this Horizon in order to assess its impact over European energy planning. In addition we study the effects over cost and risk of considering the 2050 European CO_2 Emissions reduction goal.

Results confirm that considering 2050 European Emissions target increases in 16% in terms of portfolio cost and risk and penalties in 10% in portfolio efficiency index. Carbon capture storage technologies would be necessary in order to achieve Emission reduction target, therefore they must be commercially available in 2050 and their shares would be 10%. Nuclear energy and on-shore wind would be the most important technologies in 2050 European Energy Portfolio adding 25% each one of these. However Nuclear energy would be dispensable: cost and risk would be increased about 30% as compensation.

KEYWORDS: Security of supply; diversification; risk management; energy dependence; portfolio theory.

1. INTRODUCTION

The European energy planning has been characterized by the research of a greater degree of energy security, and competitiveness and efficiency improvement (EC, 2010). Traditionally, the European Union has included in the design of its electricity generation technology mix the establishment of different aims: reaching a target of renewable technologies share in the portfolio, the pollutant emissions reduction goals, as well as an increase of the portfolio energy efficiency –including the improvement of the security of supply and the cost of the energy access by the society (Dincer, 2000; Omer, 2007; Victor, 2011). In fact, it could be concluded that the European target of a marked Renewable Energy Sources share in the portfolio could be classified into an environmental friendly policy and into a greater energy independence and security of supply levels –due to these sources are free, available and autochthonous-.

The results of the European Energy Policy in Renewable Energy Sources promotion are positive. The weight of the renewable energies in the generation mix has been increased from 14% to 23.5% between the years 2004 and 2012. Besides Renewable´s share in gross final energy consumption reached 14% in 2012 (8.3% in 2004), according data collected from EUROSTAT. However and in spite of this significant increase of the renewable energies in 2012, the European Union had to pay a bill of around 3.1% of its GDP due to the importation of natural gas and of oil -it supposed more than 400,000 EUR millions- (EC, 2014). These fossil fuels were employed in generating electricity –Natural gas share was about 18% and oil 2% in the European energy mix in 2012 (IEA, 2014).

The analysis of the energy planning can be proposed in terms of Modern Portfolio Theory (Markowitz, 1952). In this case it is possible to study the design of technologies portfolios and their level of economic efficiency from a perspective cost-risk. This methodology is based on the definition of each one of the technologies -and by extension of the combination of these in the portfolio- through the expected cost -cost mean- and the economic risk -standard deviation of the cost-. The objective function seeks the combination of technologies that minimizes the portfolio risk subject to some basic restrictions. Among them: a portfolio cost limitation, the shares could not be negative and the necessity to be equal to the unity the addition of the whole technology shares. The model offers portfolios that minimize the assumed economic risk for producing electricity and which present high diversification levels. In order to achieve a high level of diversification it is necessary that all available technologies would participate in the portfolio (De-Llano *et al.*, 2014). The reason is due to the different individual risks and correlations for each type of cost between each pair of technologies, which each Portfolio optimization model seeks to minimize they.

The research question is based on studying which is the impact in terms of cost and risk of assuming the 2050 European Emissions reduction as well as the achievement of the European efficient portfolio design for 2050. In order to reach it the model not only will include technological restrictions limits for each technology –considering the technological prospective for 2050 of the European Commission (EC, 2011)-, but also diversification index restrictions -through Herfindahl-Hirschmann, HH, thereafter-, as well as minimum efficiency limits -through the IEA-IETSAP 2010 index- and the CO_2 portfolio emissions factor limits –proposed by EC, 2011b-. The results obtained will present the different technology shares which form energy mix. Therefore, efficient portfolios will be efficient in terms of economic cost-risk, technological efficiency, environmental respect and of energy security and diversification. The assessed territory will be the European Union and the horizon, the year 2050, following the European Energy Roadmap 2050 (EC, 2011a,b).

This paper is proposed with the following structure: In the Second section the diversification concept and the different diversity indexes contained in the literature are proposed. In the next section Modern Portfolio Theory methodology applied to Energy planning is exposed. In the Fourth section the mathematical optimization model is presented, and finally the results, the discussion and conclusions and policy implications are presented in separated sections.

2. DIVERSIFICATION AND ENERGY SECURITY

Diversification is a mean to avoid or minimize those risks derived from a reduction in the power security (Awerbuch and Yang, 2007). Thus, diversification is able to reduce the impact of the power generation costs variations and tries to optimize these costs, with two important outcomes: create more robust power mix solutions and increase the power supply security. States Governments consider a diversified power system a key factor. In energy policy terms, it is essential to find ways of diversifying power assets portfolios and set up a known level of risk that includes every management variable (Muñoz *et al.* 2009).

2.1. Diversification: definition

According to Stirling (2007), the diversification concept belongs to multiple fields: ecology, physics, engineering, human life, social science, information science, economics, politics… The most relevant and numerous is that of the technology science and politics. Combustible and technologies diversification is an important matter of debate in energy politics (Stirling, 1994; Grubb *et al.*2006).

Stirling (2007) defines diversification as an “irreducible property of a system” or as “a system attribute that can be divided into categories”. That author stablishes three properties to characterize the diversification of a system: variety –the number of different categories that the system being analysed divides in–, balance –the number of different elements in each one of those categories– and disparity *–the* *number of differentiated elements*–. Each one of these categories is necessary but not sufficient (Stirling, 1994) and they are interrelated.

Hickey *et al*. (2010) gather the diversification pillars proposed by Stirling (1998): diversification drives to innovations and growth benefits, it hedges against uncertainty and decision making ignorance, it makes possible the reduction of the impact of unexpected adverse events and economic blockades and, finally, it favours the incorporation of the diverse interests in a Society.

From an economic point of view, Baugärtner (2006) points out that diversification directly relates with the number of different characteristics or types that a particular category or element has –the different alternatives to choose among– and the number of individuals in every category. In this regard, Jansen *et al*. (2004) and Gupta (2008) differentiate between fossil fuels –with the characteristic of being limited– and renewable energies –autochthonous and inexhaustible[1]–.

For their part, Bazilian and Roques (2008) opt for bind together diversification and the supply of certain type of imported energy source –geopolitical tensions can negatively affect that supply–. These authors link diversification with the existence of a wide number of combustibles in the generation portfolio, or with the availability of a wide number of generation plants for one technology, or even with the availability of a wide number of suppliers or operators.

2.2. Diversification Indexes

Stirling (2007) makes a deep study on the different indexes applicable to diversification (Table 1). In the table, N symbolize the number of elements categories; ln is the natural logarithm; p_i the proportion of the category i in the system; n the number of attributes shown as elements; $f(d_{ij})$ the distance function to measure the disparity between the categories i and j; $D_W(S)$ the system aggregated disparity; $d_W(i, S\backslash i)$ the disparity distance between the category i and the nearest element in S, excluding i.

PROPERTY	AUTHOR	SUGGESTED FORMULAE
VARIETY	Númber of categoríes (MacArthur)	N
BALANCE	Shannon Equality (Pielou)	$(-\sum_i p_i ln p_i)/\ln N$
DISPARITY	Weitzman Solow & Polasky	$max_{i\in S}\{D_W(S\backslash i) + d_W(i, S\backslash i\}$ $f(d_{ij})$
VARIETY AND BALANCE	Shannon & Wiener	$-\sum_i p_i ln p_i$
	Simpson	$\sum_i {p_i}^2$
	Gini	$1 - \sum_i {p_i}^2$
VARIETY-BALANCE-DISPARITY	Junge	$\left(\frac{\sigma}{\mu * \sqrt{n-1}}\right) * \left(\frac{1}{\sqrt{N}}\right) * (\sqrt{N-1} - \sqrt{N \sum_i {p_i}^2 - 1}$

Table 1: Suggested Formulae for diversity index. Source: Stirling (2007).

These indexes try to measure the aforementioned diversification properties –variety, balance and disparity–. In addition, the existence of simple measure elements or factors in the field of study –for instance, the financial assets historical covariance in the portfolio theory methodology– can help to define the model parameters. The model itself must incorporate the different diversification views existing in the studied matter (adaptation).

Hickey *et al*. (2010) focus on the Herfindhal-Hirschman and Shannon-Wiener indexes to define the diversification level. In terms of preferring one index or the other, the authors opt for the Herfindhal-Hirschman index because it makes possible a wider analysis by defining different weights for variety and balance.

[1] Together with the offering of an intermittent availability in the case of the eolic, solar or hydraulic sources, for example.

3. MODERN PORTFOLIO THEORY APPLIED TO THE PROBLEM OF DESIGNING POWER ENERGY MIX

The application of the Markowitz (1952) portfolio theory methodology to energy planning starts with the identification of the problem as a long-term investment selection problem. Awerbuch and Berger (2003) base their study on the non-strict assumption of the efficiency hypotheses of the financial markets efficient portfolio theory when applying the financial assets portfolio theory to the generation real assets portfolios[2].

The technology generation cost (C_t) is calculated as the sum of several production costs –investment costs, operation and maintenance costs, fuel, CO2 emissions, …– and a complementary production cost. This complementary production cost includes plant dismantling and waste management cost for nuclear generation technology; intermittence costs for renewable sources generation technologies –Eolic and PV solar–; and CO2 transport and storage costs for carbon capture and storage (CCS) technologies.

$$C_t = Investment_t + O\&M_t + Fuel_t + CO2\ Emission_t + Complementary_t$$

Portfolio theory calculates the expected portfolio cost as the sum of the total expected costs for every technology –$E(C_t)$– weighted by their shares in the portfolio. Being x_t the share of the technology t in the portfolio, the portfolio expected cost –$E(C_P)$– is:

$$E(C_P) = x_1 E(C_1) + x_2 E(C_2) + \ldots + x_n E(C_n) = \sum_{t=1}^{n} x_t E(C_t)$$

The total expected costs for each technology –$E(C_t)$– are obtained from the sum of the different generation costs.

Regarding the portfolio risk, Markowitz's portfolio theory assume the past variability as an indication of how the things will be in the future. We estimate the portfolio risk as the technology cost standard deviation calculated as the squared root of the sum of the different generation costs variances and the covariance between the fuel and the CO2 emissions costs. The covariance is zero between any other costs pair.

$$\sigma_t = \left(\sigma_{Inv_t}^2 + \sigma_{O\&M_t}^2 + \sigma_{Fuel_t}^2 + \sigma_{Compl_t}^2 + \sigma_{CO2_t}^2 + 2\sigma_{Fuel_t}\sigma_{CO_{2_t}}\rho_{Fuel_t, CO_{2_t}}\right)^{\frac{1}{2}}$$

The expected portfolio risk (σ_P), measured by the cost standard deviation for the whole set of technologies available, is a function of every technology individual costs and the risk arising from the correlation between the O&M cost of every two technologies and the correlation between the fuel costs of every two technologies.

$$\sigma_P = \left\{ \begin{array}{l} \displaystyle\sum_{t=1}^{n} x_t^2 \left(\sigma_{Inv_t}^2 + \sigma_{O\&M_t}^2 + \sigma_{Fuel_t}^2 + \sigma_{CO_{2_t}}^2 + \sigma_{Compl_t}^2 + 2\sigma_{Fuel_t}\sigma_{CO_{2_t}}\rho_{Fuel_t, CO_{2_t}}\right) + \\ \displaystyle + \sum_{t_1=1}^{n} \sum_{\substack{t_2=1 \\ t_2 \neq t_1}}^{n} x_{t_1} x_{t_2} \left(\sigma_{O\&M_{t_1}}\sigma_{O\&M_{t_2}}\rho_{O\&M_{t_1}, O\&M_{t_2}} + \sigma_{Fuel_{t_1}}\sigma_{Fuel_{t_2}}\rho_{Fuel_{t_1}, Fuel_{t_2}}\right) \end{array} \right\}^{1/2}$$

Again, x_t is the portfolio share of the technology t. For its part, σ_c is the risk of every type of cost –investment, O&M, fuel, CO2 emissions and complementary costs–.

The optimization model proposed has the aim of minimizing the portfolio cost risk –the objective function will be precisely the portfolio cost risk– and it includes a set of restrictions. After an iterative process, we obtain different cost-risk pairs for every one of the solution portfolios in the portfolios frontier. We are interested in the part of the portfolios frontier known as the efficient frontier. The efficient frontier is the set of those portfolios that have the lowest possible risk for each cost level. We highlight the social and utility perspectives of this approach, based on the idea that the design of efficient

[2] Among others, we find the short-term illiquidity of the energy investments in front of the capital assets investments; or an eventual discontinuity in the power generation markets (Awerbuch and Berger, 2003; Jansen *et al.* 2006).

portfolios will minimize the society risk level needed to reach the generation objectives with the given costs (Awerbuch and Berger, 2003; Jansen *et al*, 2006). Other studies which are based in the costs of the different technologies: Doherty *et al. (*2006), Doherty *et al.* (2008), White *et al.* (2007), Awerbuch and Yang (2007); Awerbuch *et al.* (2008), Rodoulis (2010); Allan *et al. (*2010), Zhu and Fan (2010) or Bhattacharya and Kojima (2012).

4. MATHEMATICAL MODEL

Our model mathematical formulation is as follows:

$$Min\{\sigma_p\} = Min \left\{ \sum_{t=1}^{T} x_t^2\, \sigma_t^2 + \sum_{t_1=1}^{T} \sum_{t_2=1, t_1 \neq t_2}^{T} \left(\sum_{\forall C_1} \sum_{\forall C_2} \sigma_{C_1 t_1} \sigma_{C_2 t_2} \rho_{C_1 t_1, C_2 t_2} \right) x_{t_1} x_{t_2} \right\}^{\frac{1}{2}}$$

$$= \left\{ \sum_{t=1}^{T} x_t^2 \left(\sigma_{Inv_t}^2 + \sigma_{O\&M_t}^2 + \sigma_{Fuel_t}^2 + \sigma_{Compl_t}^2 + \sigma_{CO2_t}^2 + 2\sigma_{Fuel_t}\sigma_{CO2_t}\rho_{Fuel_t, CO2_t} \right) \right.$$

$$+ \sum_{t_1=1}^{T} \sum_{t_2=1, t_1 \neq t_2}^{T} \left(\sigma_{O\&M_{t_1}} \sigma_{O\&M_{t_2}} \rho_{O\&M_{t_1}, O\&M_{t_2}}\, x_{t_1} x_{t_2} \right.$$

$$\left. \left. + \sigma_{Fuel_{t_1}} \sigma_{Fuel_{t_2}} \rho_{Fuel_{t_1}, Fuel_{t2}}\, x_{t_1} x_{t_2} \right) \right\}^{\frac{1}{2}}$$

$Subject\ to$:

$$E(C_p) = \sum_t x_t E(TC_t) = C_{European\ Union\ Portfolio}$$

$$\sum_t x_t = 1$$

$$\forall t, x_t \geq 0$$

$$x_t \leq Maximum\ percentage\ of\ participation\ of\ technology\ "t"$$

$$Portfolio\ Emission\ Factor_{CO2} \leq 2050\ EU\ Emissions\ Limit_{CO2}$$

$$Portfolio\ Efficiency\ Index \geq 2050\ EU\ Portfolio\ Efficency\ mean\ Index$$

$$Portfolio\ Diversification\ Index \geq 2050\ EU\ Portfolio\ Diversification\ mean\ index$$

Being:

t ={coal, coal with CCS, Natural Gas, Natural Gas with CCS, Oil, Nuclear, on-shore Wind, off-shore Wind, Solar Photovoltaic, Large Hydro, Small Hydro, Biomass},

$T = 12$,

x_t = Unknown model variables, meaning the participation of technology t in the portfolio (the sum of every x_t must add up to 100%).

The model includes one technological constraint for each technology considering the maximum share in 2050 energy mix. We calculate the 2050 technology maximum participation percentage (Table 2) through data contained in EC (2011a).

Technologies	Limits (%)
Coal and Coal with CCS	15.20%
CCS technologies (Coal and Natural Gas)	21.50%
Natural Gas	29.50%

Oil	2.20%
Nuclear	26.40%
Large Hydro	8.10%
Small Hydro	1.10%
Biomass	10.90%
Solar Photovoltaic	16.40%
On-shore Wind	44.30%
Off-shore Wind	4.40%

Table 2. Maximum portfolio share limits for each technology in the 2050 European Union power generation mix. Source: personal compilation from data collected from EC (2011a).

We obtain the portfolio emission factor by adding every CO_2 emission factor for each emitter technology –coal, coal with CCS, natural gas, natural gas with CCS, oil and biomass– weighted by its participation in the portfolio. The 2050 portfolio CO_2 emissions limit is established following EC (2011b), which proposes a CO_2 emissions reduction goal of 93% for electricity sector. This data equals in terms of portfolio to a maximum emission limit of 23.95 kg of CO_2 per MWh. We consider this limit into the model. Its expression is: $Portfolio\ Emission\ Factor_{CO2} = \sum_{t=1}^{6} CO2\ Emission\ Factor_t \times x_t \leq 2050\ EU\ Emissions\ Limit_{CO2}$

The portfolio efficiency index is calculated through the sum of each technology efficiency index –from data collected in IEA-ETSAP (2010)- weighted by its portfolio share. In order to establish the minimum limit for this index we calculate the mean for the efficient frontier portfolio in a base model which includes only technical and technological restrictions. And the portfolio diversification index is obtained through the expression of the HH Index for the portfolio: $\sum_i {x_i}^2$. In order to establish the minimum limit for this index we calculate the mean for the efficient frontier portfolio in a base model which includes only technical and technological restrictions.

In this study we propose different models to make a complete assessment of the results:

- "Base Model + Efficiency constraint" and "Base Model + HH Diversificatoin Index". In these cases the Base Model which contains technical and technological constraints includes the Efficiency constraint or the Diversification Index restriction. Both models not include CO2 Emissions target. Therefore they are pollutant models.
- "Emissions Model (Base Model with CO_2 Emissions constraint". This model includes technical, technological and CO_2 emissions reduction goal constraints. Through this model we can study the impact of considering the 2050 CO_2 Emission reduction goal for the European Union in terms of cost and risk.
- "Emissions Model + Efficiency and HH Diversification constraints". This model considers these two additional restrictions over "Emissions Model". This would be the most complete model due to it includes technological efficiency, environmental respect, economical efficiency and diversification-risk index.
- "Emissions Model with 50% and 100% Nuclear energy shutting down". With these models we expose the impact over the portfolio participations of a nuclear energy depletion in 2050.

5. RESULTS

In the next subsections we expose the obtained results for each one of the mathematical models proposed.

5.1. Efficient Frontiers: Average Cost and Economic Risk Portfolio

In the following Figure 1 it can be observed the results through the representations of the efficient frontiers: one for each one of the distinct models studied. Each efficient frontier is formed by the succession of solution portfolios for each model. The efficient frontier represents each pair of cost and risk values, represented in a Cartesian axis. The allocation of the different efficient frontiers confirms the existence of cost-risk impacts from each type of model considered.

The efficient frontiers with lower costs and risks are the "Base Model +Efficiency constraint" and "Base Model + HH Diversification constraint". These models do not include emissions reduction target[3]. If we consider emission reduction target ("Emissions Model"), portfolios cost and risk are increased on average by 16 %, as shown in the shift rightwards and upwards of the frontiers (Table 3). If the model also includes the portfolio diversification minimum target "Emissions Model + HH Diversification constraint) and the portfolio efficiency minimum level ("Emissions Model + Efficiency index constraint"), the average risk levels would rise 6% -additional- and the cost would be reduced 8% (Table 3). For this last case the efficient frontier become shorter by the left side, which implies lower values of cost and eliminates the lower values of portfolio risk (Figure 1).

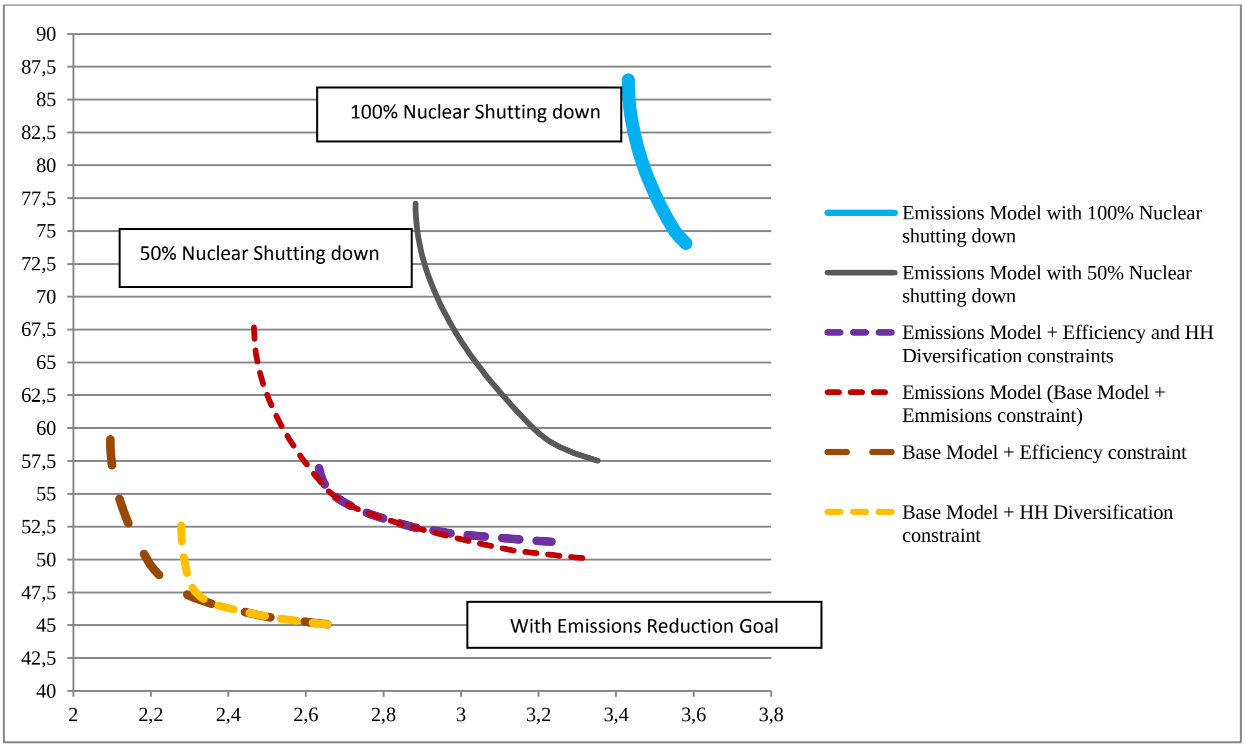

Figure 1.- Efficient Frontiers of the different Models. Source: Own author´s calculation.

If it is considered a nuclear energy share depletion in 2050, the average cost and risk values would be increased by 14% from data collected of "Emissions Model" -50% nuclear Energy shutting down-, or by 31-36% -100% Nuclear energy shutting down- (Table 3).

MODEL	AVERAGE RISK (€/MWh)	AVERAGE COST (€/MWh)
Base Model + Efficiency constraint	2.21	51.90
Base Model + HH Diversification constraint	2.36	48.61
Emissions Model (Base Model + Emmisions constraint)	2.66	58.69
Emissions Model + Eficiency and HH Diversification Constraints	2.81	53.95
Emissions Model + 50% Mininum RES constraint	2.66	58.76
Emissions Model with 50% Nuclear shutting down	3.03	67.09
Emissions Model with 50% Nuclear shutting down + Minimum RES constraint (≥50%)		
Emissions Model with 100% Nuclear shutting down	3.48	80.24
Emissions Model with 100% Nuclear shutting down + Minimum RES constraint (≥50%)		

Table 3.- Portfolio Cost and Risk mean for each model. Source: Own author´s calculation.

[3] In fact, the efficient portfolios of these models have emissions factors around 150-180 kg of CO_2 per MWh, above the limit of 23.95 kg of CO_2 per MWh of the Emissions Reduction Target for European Union 2050.

5.2. Impact over Technology efficient portfolio shares

In order to analyze the participation of various technologies, we propose assessing the efficient portfolios composition of absolute minimum cost and absolute minimum risk of the different models.

In case of absolute mínimum risk portfolios which respect the 2050 Emissions Reduction Target, It is noted that all less-pollutant technologies take part –except technology-based oil and coal-(Table 4). Both the latter as natural gas are replaced by CCS technologies. Nuclear Energy is a preferred technology because in all cases reaches the limit defined, as are the large and small hydro and off-shore technologies. The on-shore wind technology stands out as important technology because it exceeds for all portfolios a 20% share (Table 4).

<table>
<tr><th>Model</th><th>Nuclear</th><th>Coal</th><th>Coal With CCS</th><th>Natural Gas</th><th>Natural Gas with CCS</th><th>Oil</th><th>On-shore Wind</th><th>Large Hydro</th><th>Small Hydro</th><th>Off-shore Wind</th><th>Biomass</th><th>Solar PV</th><th>HH</th><th>Efficiency</th></tr>
<tr><td>Base Model + Efficiency</td><td rowspan="4">26.40%</td><td>9.87%</td><td>5.33%</td><td>17.75%</td><td>1.75%</td><td>1.65%</td><td>13.71%</td><td>5.44%</td><td rowspan="7">1.10%</td><td rowspan="7">4.40%</td><td>7.38%</td><td>5,21%</td><td>14,64%</td><td>39,20%</td></tr>
<tr><td>Base Model + HH Diversific</td><td>15.20%</td><td>0.00%</td><td>19.50%</td><td>0.00%</td><td rowspan="5">0.00%</td><td>23.13%</td><td>2.59%</td><td>5.11%</td><td>2,57%</td><td>19,03%</td><td>38,01%</td></tr>
<tr><td>Emissions Model</td><td rowspan="4">0.00%</td><td>10.76%</td><td>2.17%</td><td>10.74%</td><td>20.53%</td><td>8.10%</td><td>7.95%</td><td>7,85%</td><td>15,65%</td><td>34,65%</td></tr>
<tr><td>Emissions Model + Eficiency & HH</td><td>9.04%</td><td>2.43%</td><td>12.46%</td><td>29.07%</td><td>8.08%</td><td>5.49%</td><td>1,53%</td><td>19,03%</td><td>35,30%</td></tr>
<tr><td>Emissions Model (50% Nuclear shutting down)</td><td>13.20%</td><td>10.52%</td><td>2.19%</td><td>10.98%</td><td>28.91%</td><td rowspan="3">8.10%</td><td>9.56%</td><td>11,04%</td><td>15,46%</td><td>32,18%</td></tr>
<tr><td>Emissions Model (100% Nuclear shutting down)</td><td>0.00%</td><td>10.22%</td><td>2.23%</td><td>11.28%</td><td>37.48%</td><td>10.90%</td><td>14,30%</td><td>20,50%</td><td>29,66%</td></tr>
<tr><td>2050 Technological Limits</td><td>26.40%</td><td colspan="2">15.20%</td><td colspan="2">19.50%</td><td>2.20%</td><td>44.30%</td><td>10.90%</td><td>16.40%</td><td colspan="2">n.a.</td></tr>
</table>

Table 4.- Technology shares in Absolute Minimum Risk Portfolios. Source: Own author´s calculation.

The reduction of the Nuclear energy availability mainly lead to an increase in the share of on-shore wind technology, which reaches 29% -50% shutting down- or 37% -Nuclear energy elimination-, followed by slight increases in biomass and solar photovoltaic (Table 4).

Including Emissions Reduction Target would lead to some reduction in average portfolio efficiency, which would rise from 39% to values around 35% (Table 4). This would be caused by the abandonment of pollutant technologies plants (coal, oil and natural gas). The average portfolio efficiency would fall even more in case of reduction or elimination of nuclear energy technology.

If the absolute minimum cost portfolio is seek (Figure 2), portfolios will be composed by on-shore wind (44 %), nuclear energy (26%), Natural Gas (15 %) and Large Hydro (9%). They are less diversified portfolios with HH index values between 22% and 30% -larger than absolute minimum risk portfolios HH values- and with Efficiency index levels around 35% -minor than the best result of 40%-. Biomass and solar pv would only participate with a share larger than 6% if it were a nuclear energy depletion case (Figure 2).

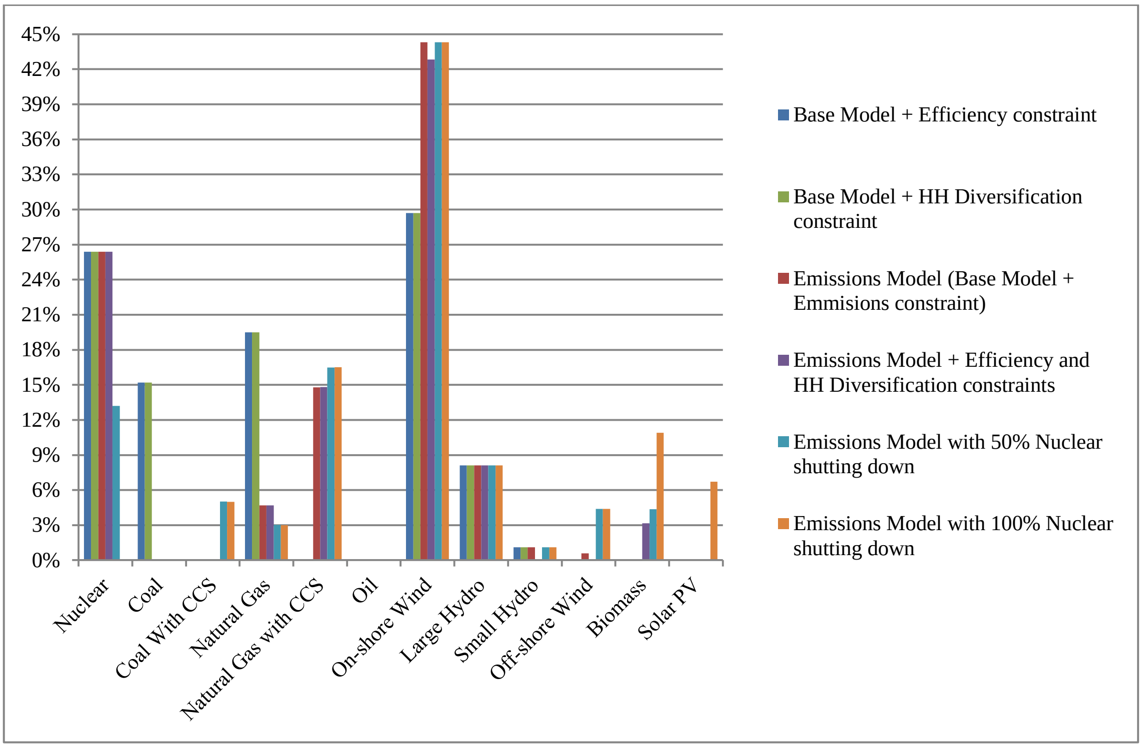

Figure 2.- Technology shares in Absolute Minimum Risk Portfolios. Source: Own author´s calculation

In both cases renewable share reaches 50%, rising to 62% (50% nuclear energy shutting down) or 75% (100% nuclear energy depletion) (Figure 2). In all Emissions Model cases 2050 the Emissions Reduction Target would be achieved.

5.3. Variation of Efficiency and Diversification-HH Indexes

The assessment of Portfolio HH Diversification Index and Portfolio Efficiency Index values permits deducing some conclusions (Figure 3). Including the compliance of the EU 2050 Emissions Reduction Target leads to less diversified portfolios (bigger values for HH Index) and to less efficient portfolios. Considering the 50% nuclear energy shutting down would have only negative effect on the efficiency Index, and the complete depletion of nuclear energy in 2050 would reduce the portfolio efficiency from 35% to 30% and the portfolio diversification index would get worse –increasing from 18% to 20%- (Figure 3).

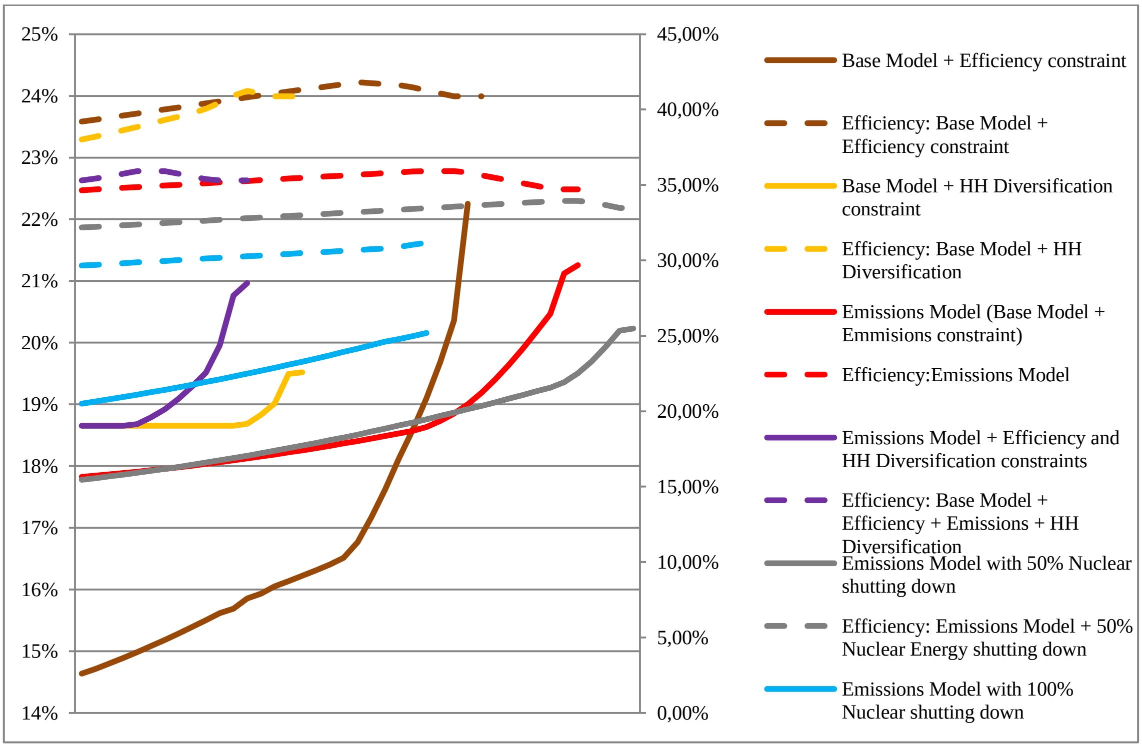

Figure 3.- Results of Portfolio Efficiency and Diversification-HH Indexes. Source: Own author´s elaboration.

6. DISCUSSION

Including the 2050 emission reduction policies will cause a negative impact both on the portfolio cost and on the portfolio risk of around 16%. In addition, the average portfolio efficiency will fall from 40% to 35%.

A reduction of 50% in nuclear generation will cause an increment of around 14% in the portfolio cost and risk. A reduction of 100% in nuclear generation in 2050 will increase the portfolio cost and risk in a 31-36%.

Regarding to generation technologies, carbon and gas with CCS will substitute the traditional carbon and gas technologies. Their shares will be at around 10%. Nuclear, large hydro and small hydro will participate at their maximum, both when we seek the minimum portfolio cost and when we seek the minimum portfolio risk. The onshore eolic technology stands out as the main technology in the portfolio, exceeding a 20% share and reaching its maximum limit of 44% if we want to reduce emissions at the minimum cost.

A reduction in the participation of nuclear generation will force the biomass and offshore eolic technologies to participate at their maximum. PV solar generation will only participate within the range of 6 to 14% in a no-nuclear generation scenario. In any case, Europe will be in a position to fulfil the emission reduction objectives –even in a no-nuclear generation scenario–.

The lowest Herfindhal-Hirschman index values are reached in those portfolios with the lowest risk. These portfolios are highly diversified. We conclude that seeking the minimum risk drives to a higher diversification and vice versa. These Herfindhal-Hirschman index values are accompanied by a high portfolio average efficiency –at around 35%–. A reduction in the participation of nuclear generation will reduce the portfolio average efficiency –down to 30% in a 50% reduction scenario and to 32% in a 100% reduction scenario–.

7. CONCLUSIONS AND POLICY IMPLICATIONS

According to the previous discussion, we can extract the following conclusions:

- Europe must assume higher levels of portfolio cost and risk –16%– if the aim is to reduce emissions.

- In the same line, that decision will reduce portfolio average efficiency at around 10%.
- The lower the economic risk to assume, the lower the portfolio diversification level.
- CCS technologies will be fundamental as substitutes of the traditional carbon and gas technologies. They must be commercially available in 2050 –and will participate at around 10% each–.
- The main technologies will be the nuclear generation technology and the onshore eolic generation technology. Hence, we understand that Europe must go on with the implementation of onshore eolic generation, reducing its technical difficulties and the costs of its incorporation to the system.
- Other generation technologies –biomass, large hydro, small hydro or offshore eolic– must be strengthened and a reduction of their costs must be seek to make minimum risk portfolios possible or to get the nuclear technology out of the portfolio.
- Nuclear generation technology would be dispensable in terms of reaching the emission reduction objectives. In this case, Europe must assume an increase in the portfolio cost and risk of around 30% on average.

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Community Renewable Energy
- Research Perspectives -

Nikola Šahović[1], Patricia Pereira da Silva[1, 2, 3]

[1] *EfS Initiative, University of Coimbra, Sustainable Energy Systems – MIT-P, Coimbra, Portugal, nikola.sahovic@gmail.com*

[2] *INESCC, Coimbra, Portugal, patsilva@fe.uc.pt*

[3] *Faculty of Economics, University of Coimbra, Coimbra, Portugal*

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ABSTRACT

The threat posed by climate change, the consequent risks for ecosystems and human health and wellbeing, has mobilized global consensus building among policy-makers around the world (Paris COP 21 agreement) to develop goals for a rapid transition to a low carbon economy fueled by sustainable energy systems. To achieve this transformation, a number of questions need to be addressed in terms of renewable energy systems (RES) deployment, including whom to involve, how to distribute costs and benefits in a fair way and on what scale energy provision systems should be designed. A growing body of literature is addressing the emergence of community renewable energy (CRE) schemes in Europe through focusing analysis on typology distinctions, governance models, financial characteristics and membership structures. This existing research has almost exclusively studied the emergence of CRE through the prism of economic and sociological theoretical models, with very few case studies, also of limited scope. The aim of this paper is to provide an overview of literature studying CRE schemes, in particular renewable energy cooperatives, to identify research gaps and to derive a research agenda for examining the developing sub-sector.

KEYWORDS: Social economy, Energy transition, Community renewable energy schemes, Renewable energy cooperatives,

1. INTRODUCTION

Rising concerns over climate change impacts, environmental sustainability and security of supply have exerted pressure towards initiating reform in the energy sector during the past two decades. Global efforts aim at a transition towards sustainable energy provision and use, in the industrial, transport, commercial and household sectors. This transition has resulted in application of new and reemergence of existing, during the past five decades to a certain extent sidelined (Mazzarol, 2009; Wirth, 2014; Yildiz et al., 2015), business models for production, distribution and trade of energy products. Namely, at the grassroots level it has included the establishment of community renewable energy (CRE) schemes, including renewable energy cooperatives and other forms of local or community based ownership/governance of renewable energy technologies. The European Union, in its Energy Union Package (EC, 2015), encourages this path through outlining a vision of an Energy Union with citizens at its core, where citizens take ownership of energy transition, benefit from new technologies, and participate actively in the market.

But what is it that is distinctive about community projects and technology installations that distinguishes them from other renewable energy (RE) projects? In broader terms, as enterprises they belong to the Social Economy. This is a middle-path, or third sector that lies between the private sector dominated by investor owned firms, and the public sector dominated by state owned enterprise. Within it they can be defined as a set of:

> *"...private, formally organized enterprises, with autonomy of decision making and freedom of membership, created to meet their members' needs through the market by producing goods and providing services, insurance and finance, where decision-making and any distribution of profits or surpluses among the members are not directly linked to the capital fees contributed by each member, each of whom has one vote..."* (EESC, 2012).

Furthermore, community energy projects have introduced new forms of socio-economic organization to the system of energy provision. While the classical regime of energy provision usually involves highly centralized energy infrastructures with „end-of-wire captive consumers" (Schreuer & Weismeier-Sammer, 2010), locally and cooperatively owned facilities for energy production can constitute a substantially different model of energy provision and distribution.

Although there is no universally accepted consensus in literature, policy makers, academics and practitioners infer varying degrees of community involvement in the CRE term (Seyfang et al. 2013). Based on their survey carried out in the UK, Walker and Devine-Wright (2008) identify the particularities of the 'process' and 'outcome' dimensions of renewable energy projects as indicative whether schemes deserve the 'community' prefix. From the first point of view, community projects are considered as those with a high degree of direct involvement and decision-making influence of local people in the planning, installation and operation of a project. The second perspective is concerned with where the benefits of a project are distributed, and is exemplified in community projects through local job creation, contribution to local infrastructure regeneration, providing local education resources and sensitizing the local population to sustainable energy provision topics (in addition to the wider global contribution towards further renewable capacities accumulation).

Within this defined scope, community renewable energy initiatives analyzed in literature still remain quite multifaceted, and a diversity of ownership models exists. Projects can be either completely owned by the community or developed in partnership with private or public sectors. Such ventures include many legal and financial models, such as cooperatives, community charities, development trusts representing communities' interests, and shares owned by community based organizations (Okkonen & Lehtonen, 2016). Patterns of ownership are determined by project initiators and managers, who themselves operate within the boundaries set by locally applicable legal forms, available financing schemes, and equity capital. The relevance of the emerging sector is embodied in the fact that such alternative ownership schemes are responsible for significant renewables' capacities in a number of European countries, most prominently in Germany where they constitute nearly 50% of installed RES capacities, 70% of which is owned by individuals, communities and cooperatives (Hall et al. 2016).

Renewable energy cooperatives constitute the single most common business model in continental Europe and are most scalable in terms of member participation and scope of technology application among the variety of institutional, legal and financial models utilized for setting up CRE schemes. They are the prevailing institutional framework for involving citizens with political, social and financial aspects of renewable energy deployment, thus "democratizing" the energy sector (Yildiz et al., 2015).

Consequently, the aim of this study is to develop a preliminary overview of directions taken by researchers investigating the field of RE cooperatives, to identify perspectives, methodologies and tools used to explore the roles and impacts of cooperatives in the energy sector and the endogenous and exogenous factors that impact their work and affect realization of set goals. The purpose the review is to summarize the existing research, their results and insights gained, and to derive a set of topics and specific questions that can serve as a roadmap for future studies addressing the subject of RE cooperatives.

The remaining sections of this paper are structured as follows. Section 2 revisits the concept of cooperative enterprise, provides a brief background of the conditions of its historical development in terms of the market induced challenges it was conceived to tackle, and describes its main features, internal organizational structure, underlying social values and ethical principles that guide operations. Section 3 contains the review of existing literature, grouped according to the main aspects of RE cooperatives that it addresses, and presents the frameworks and methodologies applied and, conclusions obtained within its scope. Section 4 concludes this paper with a summary of future research tracks proposed within the identified literature, and develops specific research questions that we think can lead to enhancing knowledge of the inner-workings, role and socio-economic impacts of cooperatives as actors in the energy sector.

2. REVISITING THE CONCEPT OF COOPERATIVE ENTERPRISE

The cooperative enterprise is active across virtually all industries, including agricultural producer supply chains, consumer retail buying groups, financial credit societies and mutual funds, housing and building societies, workers cooperatives, cooperatives focusing on health and social care, and energy producers (which are subject of this overview), distributers and traders.

According to Henrÿ (2012), who summarizes the main features of cooperatives identified in relevant literature, cooperatives are autonomous self-help and member-controlled enterprises, which members join voluntarily and in which they enjoy equal rights, responsibilities and obligations. As social economy enterprises, cooperatives must also be democratic (e.g. one-member-one-vote), and members must own a part of the assets. The universally accepted definition of cooperatives states that they "…are autonomous association of persons united voluntarily to meet their common economic, social and cultural needs and aspirations through a jointly owned and democratically controlled enterprise"[1]. They should be designed to provide services for the exclusive benefit of their members and be member – not investment – focused (Henrÿ, 2012). The creation of employment and the enhancement of member welfare and education are also features that define these organizations.

Cooperatives carry with them underlying social values and ethical principles. Around the world cooperatives operate according to the same seven core principles and values adopted by the International Co-operative Alliance (ICA). Those principles are: voluntary and open membership; democratic member control, economic participation by members; autonomy and independence; education, training and information; cooperation among cooperatives; and concern for the community[2].

According to Miller (1937), the economic fundamentals of cooperatives are its focus on the enhancement of benefits of all its member patrons rather than a relatively small number of people who share the capital of the enterprise. The cooperative seeks to remove monopoly control within markets and in doing so promote economic equality and prevent economic privilege. The history of the cooperative movement demonstrates that the cooperative is formed in circumstances where the conventional investor owned firm or the government sector solution is not viable (Mazzarol, 2009). Due to its focus on member benefits, local supply or service, and the founding principles of democratic governance that have guided Cooperatives since the 1840s, it is often an effective business model for enhancing disadvantaged communities or regions. As such, of all the areas where the cooperative enterprise has the potential to make its greatest contribution is that of regional economic development. The cooperative was born in an environment of social and economic disadvantage, as a mechanism for self-development. Its utility within rural and regional communities as a vehicle for filling market failures highlights this capability.

There are a number of cooperative business models, and they are constantly evolving in terms of internal governance and external practices (Nilsson, 1999). Traditional cooperatives are democratically controlled, with all members having an equal voice regardless of their equity share and the board of directors is made up of elected co-op members who are involved in day-to-day business operations and receives services for their contribution. In practice, a General Meeting composed of all cooperative members (or designated representatives in large cooperatives) elects the executive arm of the cooperative, the Board of Directors. In addition, cooperatives have a Supervisory Committee, tasked with overseeing the Board of Directors and reporting their findings to the General Meeting. Other cooperative models, such as the Participative, Subsidiary and the New Generation cooperative (the detailed discussion of which is outside the scope of this article) are also quite distinct in comparison to corporate entities controlled by shareholders according to their investment share and where corporate directors make business

[1] International Labour Organization - Recommendation 193 concerning the promotion of cooperatives.
See: http://www.ilo.org/dyn/normlex/en/f?p=NORMLEXPUB:12100:0::NO::P12100_ILO_CODE:R193

[2] Source: International Cooperative Alliance – www.ica.coop

decisions. They are also unlike nonprofit organizations, which are usually controlled by a board of directors who are not receiving compensation and are performing on a voluntary basis (Viardot, 2013).

3. AVENUES OF RESEARCH IN THE ENERGY COOPERATIVES FIELD

And according to the literature (Müller & Rommel, 2010; Sagebiel et al., 2014; Yildiz et al., 2015), as social and economic enterprises, renewable energy cooperatives strive for economic, social and cultural advancement of its members by following goals other than profit maximization. The one-member-one vote principle distinguishes them from enterprises with control rights that are proportionate to equity. Both the system of voluntary and open membership makes cooperatives particularly compatible with the societal expectations of multi-dimensional sustainability goals of renewable energy projects. Existing research has addressed energy cooperatives from various perspectives, most commonly through application of theoretical models, while to a lesser extent via empirical studies on the subject matter.

3.1 History, technology and energy industry value chain profiles

From the technology perspective, solar PV and wind energy technologies have in the literature clearly been documented as the most extensively applied systems in RE cooperatives. Photovoltaics are particularly attractive because of their modularity, simplicity, high reliability, low maintenance requirements and short lead times. These attributes qualify solar PV for a variety of applications such as decentralized energy supply for rural communities, solar home systems, solar parks, etc. Those favorable characteristics can also be attributed to the case of on-shore wind energy, where the simplicity of the power generation process, the high reliability of the technology and the availability of service providers (in countries where many RE cooperatives are found today) facilitate its application. In addition, an increasing number of rural biomass farmers' cooperatives are documented in Austria and the South Tyrol province of Northern Italy (Müller & Rommel, 2010; Sagebiel et al., 2014; Schreuer & Weismeier-Sammer, 2010; Viardot, 2013; Yildiz, 2014; Yildiz et al., 2015).

Numerous research papers and articles review the historical development of energy cooperatives, mostly focused on USA, Canada and Northern European countries (in particular Denmark and Germany), where a strong cooperative tradition was established since the middle of the 19th century, and where energy cooperatives played key roles in rural electrification during the first decades of the 20th century until WWII (Müller & Rommel, 2010; Sagebiel et al., 2014; Schreuer & Weismeier-Sammer, 2010; Viardot, 2013; Yildiz, 2014), culminating with the emergence of modern RE cooperatives in the 21st century. It is in these countries where modern-day energy cooperatives have grown since renewable energy technologies for distributed generation have matured. For instance, Yildiz et al. (2015) identify four phases of cooperative development in Germany: a boom in the first half of the 20th century, an interim phase until the late 1980s, a pioneering renewable energy phase in the 1990s, and a contemporary revival of the cooperative model in the energy sector in the 21st century.

The same authors catalogue RE cooperatives using the value chain approach according to their primary activities, distinguishing generation/production, distribution/transmission and trading cooperatives. They proceeded to carry out an evaluation of generation cooperatives by analyzing their financial statements from the 2010-2012 period, finding that in 2012 65% of the cooperatives had up to one million Euros in equity, 20% had more than two million Euros, while very large cooperatives with a capital of over five million Euros were an exception. In terms of membership, in the same year, 50% of cooperatives had up to 100 members, 30% between 100 and 200 members, while 19% had more than 200 members. In line with fundamental cooperative principles 60% of the surveyed energy cooperatives had relatively high equity ratios, between 31% and 100% (Yildiz et al., 2015).

3.2 Institutional analysis and cooperative governance

Apart from the overviews of historical roots, applied technologies and cooperative profiles in the industry value chain, institutional conditions, organizational analysis and transaction cost economics are the most prominent topics within cooperative literature. Transaction costs are costs associated with gathering and sharing information, as well as reaching and monitoring agreements, and are contingent on characteristics that underlie the exchange of goods and services and collective-choice activities (Villamayor-Tomas et al., 2015). As Menard (2007) explains, transaction cost economics distinguishes markets, hierarchies and hybrids as organizational forms. Investor-owned firms are classified as markets, public companies as hierarchies, whereas cooperatives are classified as hybrids, because they entail properties of markets and hierarchies. The central characteristic of hybrids is that they maintain distinct and autonomous property rights and their associated decision rights on most assets, which makes them different from integrated firms; however, they simultaneously involve sharing some strategic resources, which requires a tight coordination that goes far beyond what the price system can provide and thus makes them distinct from pure market arrangements. Distinct features of hybrids are the pooling of assets, the significance of a contract that coordinates their members, and the avoidance of ruinous competition.

In analyzing the cooperative business model, Mazzarol (2009) provides a very detailed overview, focusing on six units key to its competitive market performance:

a) Validity of the business model;
b) Member value creation and recognition within the cooperative;
c) Financial structure and funding of the cooperative business model;
d) Cooperative leadership and governance;
e) Supply chain management and strategic networking within cooperatives, and
f) Cooperative enterprise as a mechanism for regional economic development.

The author underlines strengths and weaknesses of the cooperative model across the six categories, as compared to investor owned firms (IOF) and public enterprise, concluding that cooperatives have strengths particularly in their ability to enter and service areas of market failure, where their strategic objectives are likely to focus on areas other than maximization of shareholder returns.

Researchers have also focused on institutional framework conditions (including financial support measures) in a particular country, or the comparison of such conditions in different countries, which may have incentivized the increasing emergence of energy cooperatives. A number of authors point to feed-in regulation, standardized rules for grid-connection and tax advantages as factors that have been conducive to the development of community wind projects in countries such as Denmark, Germany and Sweden (Bolinger, 2001, 2005; Breukers & Wolsink, 2007, Olesen et al., 2004).

The mobilization of sufficient capital is identified as an important precondition for the development of RE cooperatives. Contributions towards this goal can come from preferential conditions for the availability of loans and insurances (Olesen et al., 2004, Enzensberger et al., 2003) as well as by specific forms of co-ownership between commercial actors and local private investors (Bolinger, 2005). Furthermore, Enzensberger et al. (2003) also refer to socio-demographic factors such as the presence of sufficient people with sufficient financial possibilities to invest.

Hall et al., (2016) study the impact of financial institutions on renewable energy ownership models in the UK and Germany. Their conclusions suggest that if the UK and other market based economies want to encourage the development of a community energy sector that can achieve results like the one Germany, they would need to do more to develop appropriate financial institutions, such as more locally oriented banks, to support this. The authors underline that such an outcome is important in terms of realizing the potential of the civic energy sector to contribute to the energy transition in these countries, and also in terms of the extent to which benefits from these investments can be retained within local communities.

From a governance perspective and taking into account the institutional features within communities and their role in shaping decisions of community actors, literature also addresses micro-level processes of negotiation, conflict and the build-up of trust in cooperatives. This framework is utilized in the study (Wirth, 2014) to contextualize the emergence of biogas cooperatives in South Tyrol. Wirth (2014) applies a qualitative methodology composed of semi-structured interviews with South Tyrolean experts from the field of biogas, innovation, energy and agriculture, and with chairmen of seven regional biogas cooperatives. The analysis of responses showed that, apart from public support schemes for renewables, such as investment grants and financial compensation for electricity fed into the grid, four institutional features of community in particular have shaped the emergence and constitution of cooperative biogas plants. Those are: community spirit; a culturally established tradition of cooperatives; the high regard for value of local energy; and farmers' common sense of responsibility in terms of protecting the local environment, the local population, and tourism from negative effects (pollution and odor nuisance). In this article energy cooperatives are discussed as a strategy towards making energy generation and consumption more local and as a promising way of governing projects that implement renewable energy technologies. In terms of energy regions and energy self-sufficiency, community energy is expected to help transform a dominantly centralized energy supply into a more decentralized one (Späth & Rohracher, 2010).

3.3 Drivers and barriers for renewable energy cooperative enterprises

In addressing the role of urban electricity cooperatives in Germany, Muller and Rommel (2010) argue that exogenous factors in the political, economic, social and technological spheres lead to the observed growth in the number of such cooperatives, and propose a typology to describe the impact of the identified factors with regard to the governance of the electricity enterprise and the cost of ownership (table 2).

Table 2. A typology of factors with an impact on ownership costs of electricity cooperatives

Factors	Collective decision cost	Agency cost	Cost of risk
Political	1. Revised coop law;		4. Renewable Energy Act; 5. Regulation and unbundling;
Economic	2. Need for local investments and jobs;	6. Differentiation of energy; 7. Interaction producer and customer;	8. Externalities of renewables;
Social	3. Entrepreneurial civil society;	9. Change in ownership tenant relationship;	
Technical	10. Small scale generation		

Adapted from: Muller & Rommel (2010)

Based on these assumptions, the authors developed a questionnaire and interviewed two management level officials of a large electricity cooperative in Germany, in order to determine which of the identified factors were key drivers in decreasing ownership costs and facilitating the emergence of electricity cooperatives. They used a subjective scale of 1-7 for assigning weight to the factors. The results were limited as the interviews were conducted in just one cooperative, and inconclusive as the two interviewed officials did not concur as to which factors were key drivers.

In a second example, to identify barriers towards community energy projects and the role of energy cooperatives in overcoming barriers to adoption of renewable energy Viardot (2013) conducts a literature review and applies the Technology Acceptance Model (TAM[3]) to the findings. The author identifies ten barriers that cooperatives are facing in adopting RE, including the perceived ease-of-use (PEOU); potentially low usefulness due to low reliability (intermittence); free-riding individual behavior; a lack of participation in community groups and lack of familiarity with RE technology.

Based on findings, the author designed a semi-structured questionnaire and interviewed 9 cooperatives (seven in Canada and one each in Denmark and the UK) in order to determine which technological, ontological and social, financial and legal, and physical hindrances represent barriers to adoption of RE in cooperatives and how those cooperatives address them. The study concludes that cooperatives undertake the following marketing initiatives to mitigate RE identified barriers:

- Information dissemination through websites, some very in-depth on the physics of RE technologies;
- Free seminars, workshops and public lectures;
- Educational tours to RE facilities or co-ops;
- Visits to energy expos.

[3] Originally an information systems theory that models user technology acceptance, the TAM suggests that when users are presented with an innovation, numerous factors influence their willingness to use it. The idea of the model is to describe external factors affecting internal attitudes and usage intentions of the users, and through those, to predict the acceptance and use of the system (Viardot, 2013).

3.4 Socio-economic impacts of CRE schemes

Several studies argue that small-scale community-based wind power projects receive strong levels of support from local people (Barry & Chapman, 2009; Rogers et al., 2008; Warren & McFadyen, 2010), while other authors indicate that local opposition towards wind energy projects, the so called NIMBY[4] attitude, has been reduced through local participation, participatory decision-making processes, and (equal or fair) distribution of economic benefits (Agterbosch et al., 2004; Breukers & Wolsink, 2007; Musall & Kuik, 2011; Toke et al, 2008).

However, although superior regional socio-economic impacts, as compared to those of the traditional enterprise, are commonly underlined as benefits of the cooperative model, we did not encounter studies that strive to evaluate the validity of such statements in the context of a specific RE cooperative. Nevertheless, two independent studies addressing CRE projects in the northern Scottish islands do endeavor to compute the contrasting local socio-economic impact of wind energy developments, on the one hand the impact they induce as a CRE scheme, while on the other hand their contribution to the local economy and society achieved through operating as a traditional investor owned firm.

Okkonen and Lehtonen (2016) develop a regional-level input-output model for analyzing the CRE role in generating place-based income and employment effects of community wind power in three groups of Scottish islands. The results show that employment impacts of reinvestments can be eight times higher compared with pure traditional investor owned wind-power production impacts, building an opportunity for the maintenance and regeneration of the local economy. The social enterprise can, according to its results, be seen as an important tool for regional policy as the investments to the social enterprise in renewable energy offer development opportunities for such distant and sparsely populated rural areas. In the study region, the reinvestment of revenues offered an opportunity for organizing local services, developing community businesses and investing in infrastructure and communications. Similarly, revenues can be used to secure basic services such as health and education, the lack of which might limit future economic activities in peripheral rural areas. The authors suggest that social enterprise could be combined with appropriate place-based policy to integrate energy and regional policy aims at the community level. This would have positive impacts on economic regeneration, achieving the goal of low carbon economies, social cohesion and social acceptance of renewable energy.

The potential local economic and employment impacts of a proposed large scale on-shore wind energy project in the Shetland islands (Scotland) were assessed a study developed by Allan et al. (2011). The researches applied a Social Accounting Matrix (SAM), which they described as more appropriate tool than traditional input-output analysis for capturing the economic impacts in the particular case. Upon sensitivity analysis of various ownership models and alternative benefits compensation mechanisms to the local community, the study found that local ownership confers the greatest economic benefits to the local community by a substantial margin.

4. FINAL REMARKS

Energy production, distribution and consumption have all both technical and human components, and involve human causes and consequences of energy-related activities and processes as well as social structures that shape how people engage with energy systems. To do so, it is necessary to undertake a more specific research. Therefore, it would be interesting to look beyond the dimensions of technology and economics to include these social and human elements in energy cooperative research. Only a few of the identified studies utilize field research, surveys, interviews or focus groups, and those that do are quite limited in terms of their scope, cross-national or other benchmarking aspects. Such methods are essential to capturing the human dimensions to energy production/use in cooperatives. Human centered methods are also necessary to uncover the multidimensional role of attitudes, habits and experience (Sovacool, 2014) in shaping cooperative actions.

In addition, literature suggests that further investigation of the role of energy cooperatives in the energy transition can include:

- Development of a specific methodology to evaluate whether the specific attributes of cooperatives put them in a better position than other businesses to undertake RE projects (Viardot, 2013).

[4] Not in my back yard

- Comparative cross-country analysis on drivers and barriers that could yield new insights on cultural and institutional characteristics that foster the deployment of cooperatives (Yildiz et al., 2015). The analysis and cross country comparison of citizens participation schemes can provide valuable findings, and can include appraisal of business models, research on interaction on the different political and institutional frameworks within the diffusion of citizens participation schemes as well as research on transferability of existing business models to countries where citizens are not active in the field of renewables, or where deployment is progressing slowly, so that the transition towards clean energy can be further streamlined.
- Analysis of the effects of policy measures and the legal framework on citizens participation in such schemes, including how business models can they be modified to encourage stronger cooperative development in areas where they are comparatively less present (Yildiz, 2014).
- International comparative examination of how the transition of ownership and control structures from the traditional to the newer form of cooperative (i.e. "New Generation Cooperative") has impacted governance and management of cooperatives that have gone through the transformation process (Mazzarol, 2009).

Based on these and further insights from literature, a number of specific research questions can be formulated to enhance the following perspectives (along with proposed tools and methods):

- Institutional framework conditions:
    a) How do country specific policy circumstances (including cooperative law and renewables deployment) impact the foundation of cooperatives in the renewable energy sector?
    b) The role of cooperative banks in financing cooperative enterprise in the energy industry, and their existing relationships if applicable.
- Financial performance: How do energy cooperatives perform compare to investor-owned firms, taking into account also non-conventional community benefit performance aspects? (Kaplan and Norton "Balanced Scorecard"; Financial and non-financial performance indicators).
- Resources: How does location specific social capital support the development of cooperatives in the renewable energy sector?
- Actor roles: What are the characteristics of actors involved in RE cooperatives and how do they differ across nations and rural/urban environment? How might they be attracted to join projects?
- Objectives: What are the specific objectives of RE cooperatives as defined by their founding members? Which objectives seem to be fruitful in order to push a wider diffusion of renewable energy projects, across cultural and economic settings in Europe?
- Cooperative governance:
    a) How can cooperative governance structures support the organization of projects for renewable energy production and consumption? (Institutional Analysis and Development Framework – Cooperatives as managers of Common-pool Resources (Wolsink 2012);
    b) Which problematic areas arise regarding the legal form of cooperatives, and how adjustments have been made to improve competitiveness? (This question has been extensively addressed in literature, however in a speculative nature, without specific empirical observations)
- Regional development and poverty alleviation: Do RE cooperatives contribute to regional development (economy/welfare/quality of life), and can the cooperative model be applied in poverty stricken regions for provision of energy (examples from developing countries not found in literature thus far) – and in turn stimulate other economic activities among such populations?

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Solar PV in Africa - Realities to Confront!

David A Quansah[1, 2], Muyiwa S Adaramola[1], Lena D Mensah[2]

[1] *Department of Ecology and Natural Resource,*
Norwegian University of Life Sciences (NMBU), Ås, Norway

[2] *The Energy Center, Kwame Nkrumah University of Science and Technology (KNUST),*
Kumasi, Ghana

DA Quansah: david.ato.quansah@nmbu.no
MS Adaramola: Muyiwa.adaramola@nmbu.no
LD Mensah: ldmensah.coe@knust.edu.gh

ABSTRACT

Africa is certainly endowed with significant amounts of renewable energy (RE) resources, including solar energy. It receives some of the highest levels of annual radiation globally. Yet Africa remains the poorest region of the world, in terms of energy access – in contrast with its endowment. This reality, of abundant sunlight, leads some to have an almost fairy-tale idea about solar photovoltaic (PV) and its current role in enhancing access to energy in Africa.

The institution of regulatory frameworks, which among others establish feed-in tariffs (FiTs), priority dispatch rules and RE purchase obligations has typically promoted centralized and utility-scale PV systems. In the implementation of FiTs, financial integrity of utilities and their ability to honor long-term contracts has been questioned by financing institutions, leading some Independent Power Producers (IPPs) to request government sovereign guarantees. Also, the ability of African power grids to accommodate large amounts of variable renewables (VRs) such as solar PV is a major issue that significantly constraints utility-scale PV.

Small-to-medium scale grid-connected PV systems have significantly contributed to installations recounted in many countries around the world. Such systems have also enabled home owners to off-set some of their consumption from the grid, and in some instances to attract revenues. The grid, therefore, serves as a battery for owners of these systems. In most Africa countries, however, power outages are common-place, and the grid is unreliable. The output of grid-connected systems is, therefore, reduced as a result of the instability of the grid. The grid no more serves as a reliable battery and system owners who wish to have stable power, therefore, need to make additional investments in battery storage.

Additionally, financing still presents a major obstacle. High bank interest rates and short loan tenors make it difficult to deploy these systems with long-term financing. At the lower end of the PV user chain is the category of Solar Home Systems and other smaller applications for lighting, phone charging, etc., where requirements of upfront payment for installations still persist.

For solar PV and other modern renewables to play a significant role in Africa's development, massive investment is needed in the basic infrastructure that makes RE integration possible - robust transmission and distribution system built on reliable dispatchable baseload and mid-merit plants (both conventional and non-conventional) with adequate reserve margins. Financially sound utilities are a requirement for operationalizing RE instruments such as feed-in tariffs.

Against this backdrop, this paper, examines some technical, regulatory and economic issues surrounding large utility-scale, small-to-medium scale roof-top systems and smaller home applications with battery storage in Africa.

Keywords: *Utility-scale PV systems, Levelized Cost of Electricity, reserve margins, Solar Home Systems, Feed-in-tariff*

1 INTRODUCTION

The International Energy Agency (IEA) estimates that about 620 million people in Africa, representing two-thirds of the continent's population of approximately 1 billion, do have access to electricity (IEA, 2014). In several countries, (Mauritania, Guinea, Burkina Faso, Niger, Chad, Central African Republic, D. R. Congo, etc.) more than three-quarters (75%) of the population has no electricity. With 15% of global population, Africa remains the most energy poor region in the world, contributing just about 2.4% of global GDP. As shown in Table 1, countries in the OECD region have average annual per capita electricity consumption of over 8000 kWh, however, the average for Africa is just around 590 kWh, 20% of the global average and 7% of what pertains in OECD economies.

Table 1: Key World Energy and Economic Indicators

Region/Country/Economy	Population (Million)	% World Pop.	GDP (Bn 2005$)	Share of Global GDP (%)	Electricity Cons. Per Capita (kWh)	Cons per capita against global avg.(%)
World	7036	100	54588	100	2,972.57	100
OECD	1254	18	39490	72.3	8,090.11	272
Middle East	213	3	1430	2.6	3,708.92	125
Non-OECD Europe and Eurasia	341	5	1644	3.0	4,551.32	153
China	1358	19	4756	8.7	3,488.22	117
Asia	2320	33	3568	6.5	892.67	30
Non-OECD Americas	467	7	2369	4.3	2,096.36	71
Africa	1083	15	1331	2.4	591.87	20

Data source - (IEA, 2014b)

The picture becomes gloomier when the data is analysed to exclude the Maghreb Regions (Algeria, Egypt, Libya, Morocco, and Tunisia) and South Africa. These countries together constitute about 20% of Africa's population, but generate and consume more than 75% of electricity on the continent, and have a per capita consumption of over 2000 kWh/year. This leaves the rest of Africa (predominantly SSA) with annual per capita consumption of around 170 kWh (US EIA, 2014). This energy situation stands in contrast with the vast energy resources that Africa is blessed with, both conventional and non-conventional.

Most parts of Africa receive in excess of 2000 kWh of solar energy annually. In view of this remarkable resource endowment, many have questioned why solar energy is not leading the way in Africa's electrification, particularly, in the face of rapid uptake of the technology at the global level – averaging 50% p.a. over the period 2004 to 2014 from 2.6 GW to almost 180 GW (REN21, 2015).

In this paper, we examine some of the factors that hold back the deployment of Solar PV technologies by considering applications at three different levels - off-grid, decentralized grid-connected and large-scale utility – and propose some measures to address them.

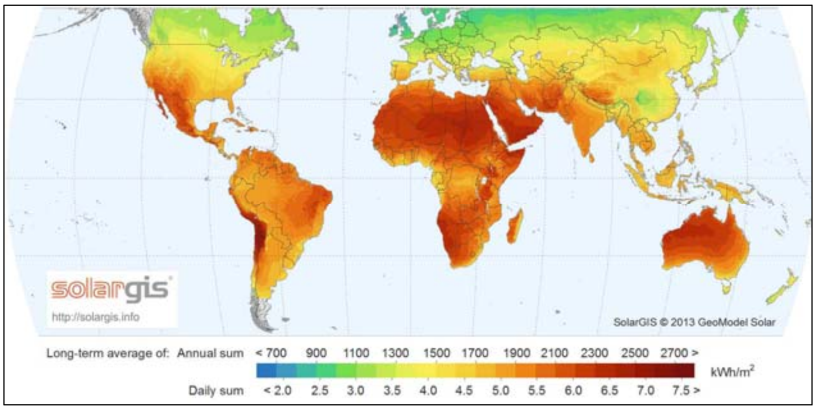

Fig 1: Global Solar Radiation Map (GeoSun Africa, 2013)

2 SOLAR PV IN AFRICA - THE ISSUES

2.1 Off-grid systems

2.1.1 Background

With average electricity access rate of just over 30% in Africa, a large population are without the electricity grid, and can currently only benefit from solar through off-grid applications. Such applications (shown in Fig 2) include solar home systems (SHS), solar lanterns, mobile phone charging systems, etc. While these systems often replace inferior and health-threatening options such as kerosene lamps, dry cells, candles and sometimes outright darkness, they represent the highest-cost end of solar PV applications.

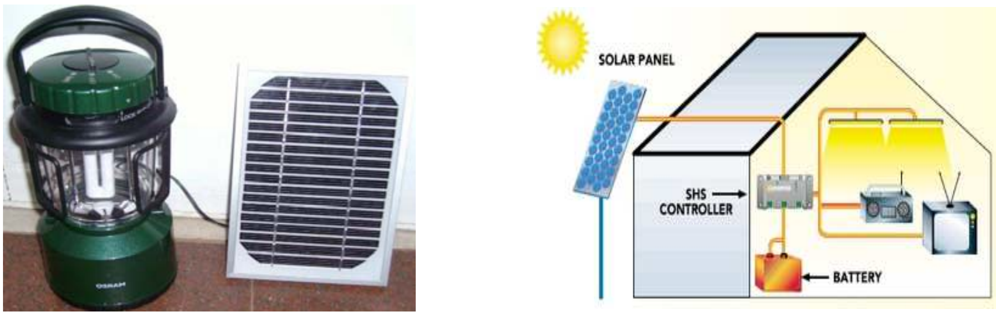

Fig 2: Off-Grid Solar PV Systems (left – Solar lantern[1], Right – Solar Home System [2](Schematic))

The IEA reports in its publication - *Pico Solar PV Systems for Remote Homes* (IEA, 2013), - that these Pico systems could cost as much as $20/W ($20,000/kW). In Kenya, the cost of energy from solar home systems was reported as between $1 - $7.6/kWh, depending on the battery type used (Pode, 2013). Some reasons for the generally high cost of these systems include the fact that they must always come with battery storage (which significantly increases the cost), underdeveloped markets and supply chains (NORPLAN/NORAD, 2012) (GIZ, 2013). The cost of PV with battery storage remains very high, and even in relatively developed markets such as Germany and US, such systems are hardly cost-competitive with grid-tied PV-inverter option (since cost of battery is avoided) and the cost of electricity from the utility grid. Projections from charts made available by IRENA (International Renewable Energy Agency) in Fig 3 indicate that, while grid-parity was reached for private households in Germany in 2011, parity for systems that include battery storage will have to wait until sometime in 2016 to be competitive.

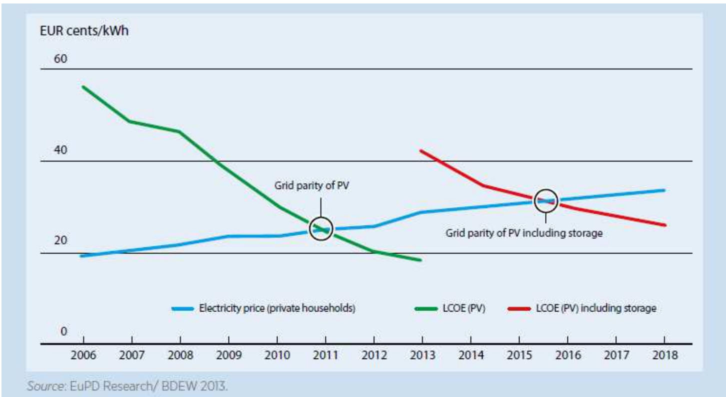

Fig3: Grid parity of PV-storage in Germany (IRENA, 2014)

[1] http://www.solagenpower.com/SolarLanterns.html
[2] http://www.zimsolar.co.uk/L1_rural_solar_systems.htm

A similar study by the Rocky Mountain Institute (RMI), (RMI, 2014) shows that a significant segment of American electricity consumers will have to wait for up to 30 years for PV with storage to become competitive with grid-based electricity (see Fig 4).

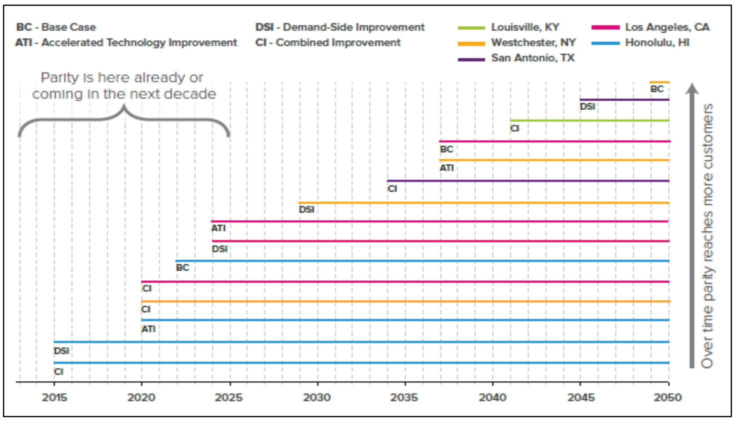

Fig 4: Grid Parity Timeline for Residential Customers (RMI, 2014)

An energy cost profile for solar PV applications is shown in Fig 5, and it depicts how the nature of application influences the cost of electricity. In general, the investment cost and cost of energy decreases as the scale of PV systems increases.

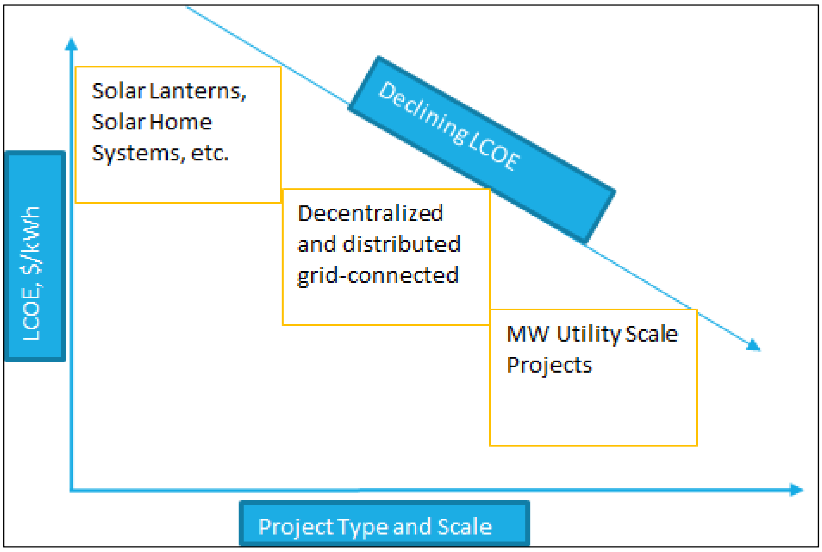

Fig 5: Solar PV application and cost of electricity (Authors' Construct)

2.1.2 Key issues

Although, recent years have seen the development of several innovative micro-financing schemes in support of the delivery of off-grid PV solutions to many rural communities in Africa, these micro-credit schemes, nonetheless, only make it easier to pay for systems whose energy delivery cost remain the highest. Since some of the off-gird packages come in low wattage units and are designed to go for as low as $36 or less (IEA, 2013), the extremely high cost of energy that these end-users are paying tends to be obscured. Solar PV with battery storage currently occupies niche spaces such as remote telecoms repeater stations and off-grid vacation homes for the generally well-to-do (IEA, 2013b).

2.2 Distributed and decentralized systems

2.2.1 Background

Grid-Connected systems typically comprise solar modules and grid-type inverters, thus avoiding the cost of batteries. They are usually installed utilizing roof-top spaces and (and car parks), and are designed to feed into the distribution utility grid (with configurations that allow self-consumption). Fig 6 shows the schematic of a grid-connected solar PV system.

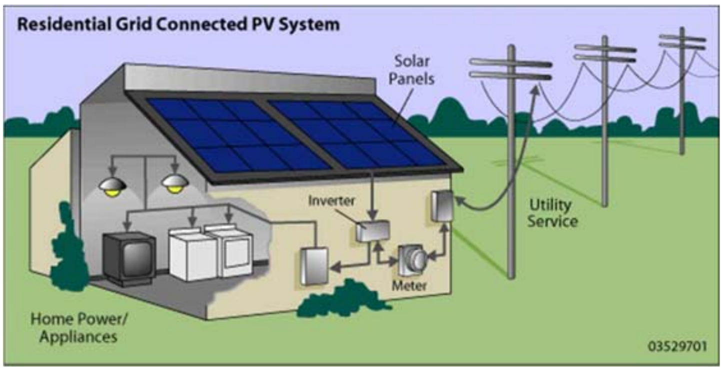

Fig 6: Schematic of a Residential Grid-Connected PV System (http://www.mathworks.com/)

Because they avoid the cost of batteries, they significantly reduce system cost (installation cost), and, therefore, the cost of energy generated is lower than systems with battery storage. Small grid-connected systems mounted on roof tops have been responsible for powering the phenomenal growth of solar PV in Germany and other leading countries around the world (Fig 7). They have been incentivized by schemes such as (micro) Feed in Tariffs (FiTs) and net-metering schemes. By close of 2014, the number of countries with feed-in policies had risen from 34 in 2004 to 108 (REN21, 2015).

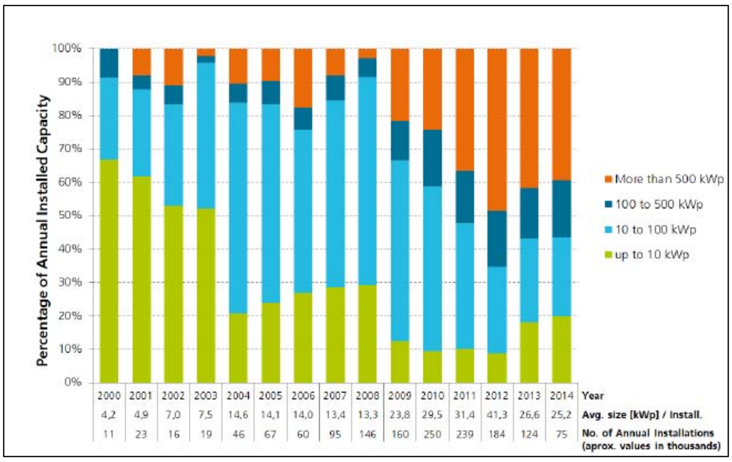

Fig 7: PV Systems Annually Installed in Germany (Fraunhofer ISE, 2015)

2.2.2 Key issues

2.2.2.1 Low grid coverage and unstable grids

With rather low levels of electrification, a very significant proportion of the population in Africa simply do not currently have this lower-cost PV application as an option, as argued in section 1;the estimated two-thirds without electricity in Africa can only currently utilize PV in off-grid mode. This consequently limits the extent to which grid-connected applications could be deployed in Africa. In countries such as Ghana, South Africa, Nigeria and the countries of the Maghreb region, where grid coverage and electrification rates are high, the stability of the grid is a major obstacle. The World Bank estimates that African manufacturing enterprises experience power outages on average 56 days per year (World Bank, 2013). Fig 8 from the World Bank Enterprise Surveys shows the frequency and duration of outages of occurrence

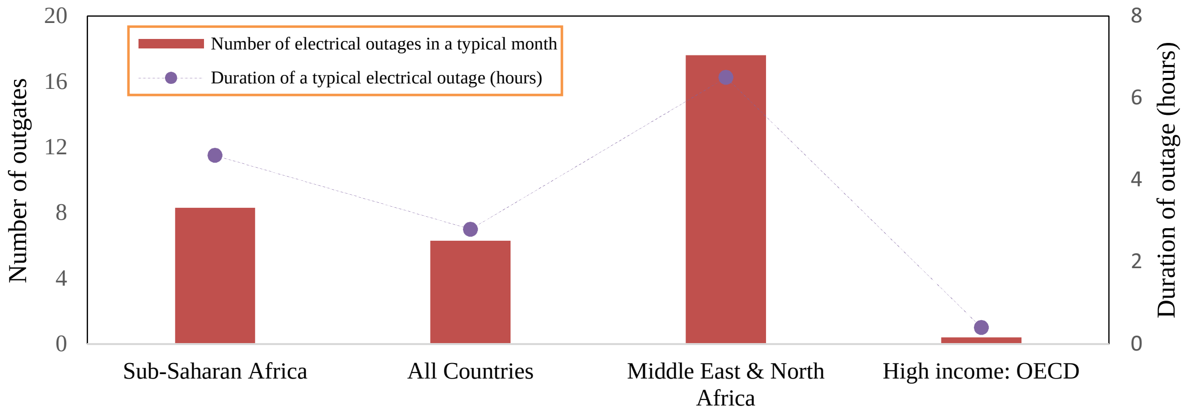

Fig 8: Power Outage Statistic in Africa and Other Regions (World Bank, 2015)

System owners in OECD and other developed economies tend to use grid-connected solar PV (supported by Government incentives) to reduce consumption from grid and reduce utility bills. The grid is used as a battery into which energy is pumped when the sun is shining, and from which energy is drawn during periods of low or no irradiance. Africa's grids, however, are characterized by high downtimes and cannot serve as *storage batteries*. Since grid-connected systems are designed to disengage from the grid when it is down, the high power outage rates of the distribution networks in Africa means that such PV systems will stop generating when the grid is down. In the absence of loads such as pumps which are able to operate directly on the output of PV systems, the installation produces no energy even when the sun is shining. Additional investment in battery systems and Islanding systems add significantly to cost and complexity. A major need in Africa is reliable power for domestic users and businesses, and this need is technology-blind. In the service of this need, viable technology options include gensets (gasoline and diesel based) and solar PV with battery storage. Gensets are commonplace because they are cheaper to purchase and even though LCOE is higher than solar PV (with storage) in some instances, it is, from a practical point of view, a more accessible option than the alternative, in which one pays now for electricity to be used in several years to come. Generator ownership rate among enterprises is the highest in the world (see Fig 9).

2.2.2.2 Absence of enabling regulations and policies

Although many African governments are beginning to put in place supportive regulations and policies, the framework that guides interconnection with the distribution network and spelling out sell-back rates and periods of accounts balancing between customer and distribution utility does not exist in several countries. Tunisia is reported to have a net-metering system in place (energypedia, 2015). Ghana has also recently developed its net metering code (Energy Commission Ghana, 2015f), while Kenya and South Africa are developing such regulations (energypedia, 2015), (NERSA, 2015)[3]. In the absence of required regulations, technical capacity, for example in the installation and management of bi-directional meters and implementation of new or adapted information management systems are lacking. Additionally, the general absence of investment support and long-term, low interest rate credit (as pertains elsewhere) implies that systems have to be equity financed (and most often paid for prior to installations). The alternative is to finance with short-term, high interest loans, with rates as high as 30% p.a. (Government of Ghana, 2015).

[3] South African National Electricity Regulator

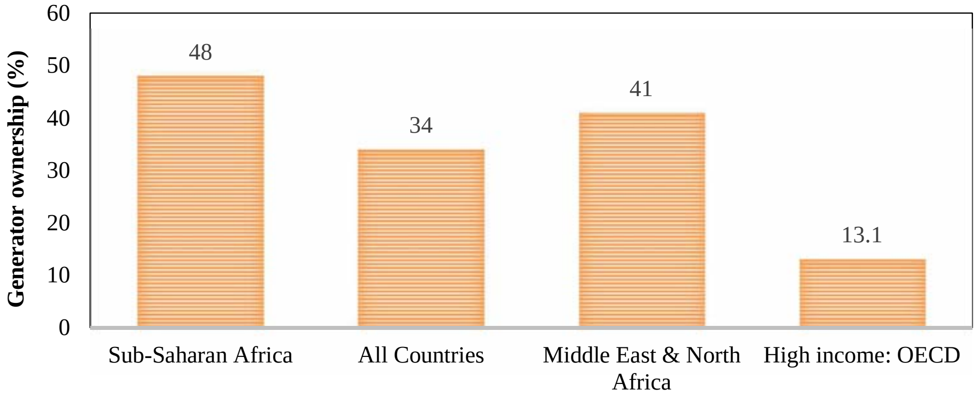

Fig 9: Generator ownership among enterprises (World Bank, 2015)

2.3 Centralized/utility scale projects

2.3.1 Background

These are usually in the order of megawatts, and are developed by power generation utilities (both state and private). In 2010, the West African island of Cape Verde commissioned a 7.5 MW solar PV power plant, which was reputed to be Africa's largest at the time (ECREEE, 2010). Since then, several African countries have either commissioned plants of similar scale, or concluded contracts for construction. Selected projects are shown in Table 2. The potential for utility-scale solar PV in Africa is enormous. Studies by IRENA (IRENA, 2014b) suggest a theoretical annual electricity generation potential of 660,000 TWh for Solar PV in Africa. This is approximately 900 times the current annual generation of 750 TWh on the continent. A study by United Nations Environment Programme (UNEP), which investigated the potential for solar electricity trade in West Africa, estimated that about 1% of land in Ghana could generate up to 16700 GWh of electricity per year (UNEP, 2015).

The cost of solar PV continues to drop and in 2014/15, tenders in Brazil, Dubai and Panama yielded electricity prices as low as \$0.06/kWh - \$0.087/kWh (REN21, 2015). These bright prospects, notwithstanding, key barriers need to be surmounted for Africa's power sector to realize the potential contribution of Solar PV at the utility scale.

Table 2: Solar PV Projects across Africa

Country	Capacity, MW	Year	Project Developers/Funding Agencies
Egypt[4]	50	2015	New & Renewable Energy Authority (NREA)
Burkina Faso[5]	30	2014	SONABEL, EIB, EU
Nigeria[6]	30	2013	Nigeria National Energy Council
Zambia[7]	100	2015	Energy Zambia Limited (IEZL)/General Electric/ Rhino Engineering/Belectric
Kenya[8]	320	2015	TARDA (Kenya), Ultra Clean Energy Solutions and Hitachi India.

[4] http://www.pv-magazine.com/news/details/beitrag/egypt-unveils-50-mw-pv-project-and-50-mw-module-fab_100019986/#axzz3k1TUJVhY
[5] http://www.eib.org/infocentre/press/releases/all/2014/2014-201-west-african-solar-project-gets-eur-23m-eib-backing.htm
[6] http://www.pv-magazine.com/news/details/beitrag/nigeria-partners-with-germany-on-420-mw-solar-projects_100013206/#ixzz3k1fUmtIr
[7] http://www.agenceecofin.com/solaire/1606-29816-zambie-general-electric-entamera-bientot-la-construction-de-la-centrale-solaire-de-kumi-kumi-zuba
[8] http://www.greentechlead.com/solar/tarda-plans-320-mw-solar-park-in-kenya-28222

2.3.2 Key issue - technical capacity of grids

The solar resource varies significantly throughout the day and is not available in the night. This variation in resource availability directly affects the output of power plants, and presents significant challenges for grid managers who must keep it balanced and stable. An IEA report on the integration of variable renewables into electricity grids (IEA, 2011) emphasizes the need for grids to have flexibility resources to manage the intermittency. It identifies dispatchable power plants with the ability to ramp output up and down on demand as the largest source of flexibility in current power systems.

African grids are characterized by very low or no reserve margins, and countries like Ghana and South Africa have been shedding load because of inadequate levels of generation. This situation puts constraints on the potential of solar PV at the utility scale. Partly due to grid-integration challenges, globally, in spite of the rapid growth of solar PV, it still constitutes a rather small amount of generation in national grid networks (See Table 3).

Table 3: Levels of Solar PV Integration in Regional Networks

Region	Installed Capacity (Total), GW	% Solar (Capacity)	% Solar (Generation)
Global	5683	1.70%	0.4
EU	960	7.20%	2.1
OECD Americas	1356	0.10%	0.2
OECD Asia Oceania	454	2.20%	0.5

Source: (IEA-ETSAP/IRENA, 2015)[9]

The EU, which is world leading in solar installations, accounts for just about 7% of its installed capacity and 2.1% of generation with solar PV, and this is dominated by small distributed systems as shown in Figure 7. The challenge of integration and potential impact on national grid led authorities in Ghana, in 2014, to impose a cap of 150 MW for utility scale solar PV in the national grid, in capacities not exceeding 20 MW per single installation (PURC, 2014).

3 WAY FORWARD AND CONCLUDING REMARKS

In the case of off-grid systems, which typically come in low wattage and have restrictive usage, they must clearly be seen as interim and transitional solutions. Additionally, they must be delivered with significant levels of grant financing as a means of ensuring equity between those in off-grid locations and grid-connected communities. It should be noted that in most African countries grid infrastructure is usually publicly financed (including funds from taxes of off-gird dwellers). Therefore, effort should made either to extend grid or to develop community-based micro/mini (hybrid) grids depending on economics and other strategic considerations within the national context. High quality electricity, beyond basic lighting and mobile-phone charging services, is a pre-requisite for the growth of enterprises and an escape from the vicious cycle of poverty for millions in Africa.

For the distributed and decentralized systems, regulations need to be developed for this segment of PV applications, as many of the current arrangements focus on large MW-scale PV systems. This segment holds enormous prospect in unlocking the potential of solar power in Africa, and opening up participation by thousands of homes and organizations.

To enable power grids in Africa to integrate significant shares of large-scale centralized power plant, there is the need to invest in strengthening transmission infrastructure. The new transmission infrastructure should have a portfolio of dispatchable power technologies (both conventional and non-conventional) that have the ability to ramp up and down at the required rates in response to fluctuations that Solar PV plants introduce to the interconnected systems. This implies improving reserve margin of the power systems.

[9] The Energy Technology Systems Analysis Programme (ETSAP) is an Implementing Agreement of the International Energy Agency (IEA), first established in 1976.

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Shape design of the duct for horizontal axis tidal turbine using both numerical and experimental studies

Chul H. Jo[1], Kang H. Lee[1], Do Y. Kim[1], Su J. Hwang[1], Chan H. Goo[1*]

[1] *Department of Naval Architecture and Ocean Engineering, Inha University, Incheon, Korea,*
[*] *Corresponding author : chanhoegoo@inha.edu*

ABSTRACT

Recently, focus has been placed on renewable energy resources because environmental concerns regarding the exploitation of hydrocarbons are increasing. Among the various renewable energy sources, ocean energy has very huge potential. Especially tidal current power (TCP) is recognized as the most promising energy source in terms of predictability and reliability. The enormous energy potential in TCP fields has been exploited by installing TCP systems. The flow speed is the most significant factor for power estimation of a tidal current power system. The kinetic energy of the flow is proportional to the cube of the inflow velocity, and the velocity is a critical variable in the performance of the system. Since the duct can accelerate the flow velocity, its use could expand the applicable areas of tidal devices to relatively lower velocity sites. The inclined angle of the duct and the shapes of inlet and outlet affect the acceleration rates of the flow inside the duct. In addition, the volume of the duct and flow around the duct can affect the flow velocity amplification performance. To investigate the effects of parameters that increase the flow velocity, a series of simulations are performed using the commercial computational fluid dynamics (CFD) code ANSYS-CFX. Experimental investigations were conducted using a circulation water channel (CWC).

KEYWORDS: Ocean energy, Tidal current power(TCP), Duct, Circulation water channel, Computational fluid dynamics(CFD)

1 INTRODUCTION

Tidal current power (TCP) from ocean energy has huge potential throughout the world. It is a very reliable and predictable resource. Therefore many researches have been performed regarding applications of tidal current power systems.

The flow velocity is the most critical factor for power generation from tidal currents since the kinetic energy of the flow stream is proportional to the cube of the flow velocity. Among several types of current turbine systems, the application of duct could increase the upstream velocities and the power extraction from the current. Numerous researches have been presented regarding duct applications for TCP systems. [1] Several experimental studies on a ducted horizontal axis turbine (HAT) system were conducted. [2] The effect of the diffuser angle on ducted turbine performance was described. [3] And computational fluid dynamics (CFD) analyses of the effects on inlet shapes on the inside velocity of a duct were carried out. [4] A duct system using hydrofoil sections around the turbine was introduced in 2013.

A strong current is required for the tidal converters, and it can be generally applied at a region that has a relatively higher flow velocity. However the application of duct can accelerate the flow velocity, it can potentially broaden the applicable areas of tidal devices to relatively lower velocity sites. In many researches, it has been proven that a duct could enhance the amount of power production by amplifying the flow velocity, but the duct should be designed by considering the specific environmental conditions and the whole concept of the structure. This paper describes the preliminary design of a duct that can be applied to a tidal current power system moored to a seabed and the flow characteristics around the duct based on CFD analyses. And experimental studies were carried out to validate the CFD results

2 CONCEPT OF OVERALL SYSTEM

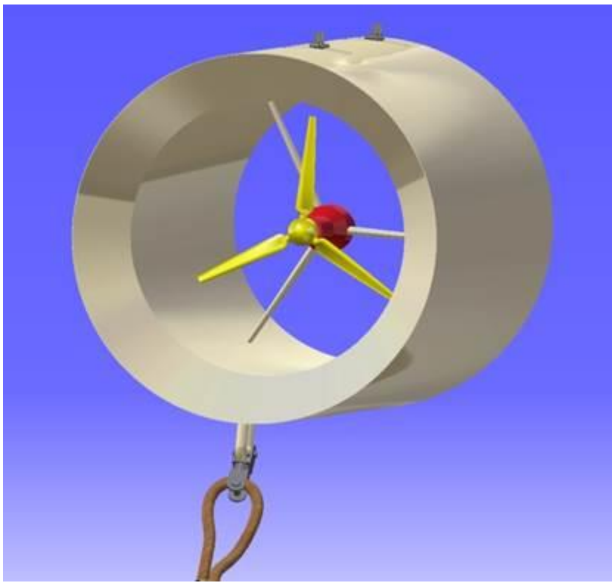


Fig. 1. Schematic view of TCP with a single point mooring system

Many sites (such as a drain channel in a conventional power plant and islands areas) have a relatively lower current velocity. A single point mooring system could be applied to a TCP system with duct structure for easy installation and maintenance. As shown in Fig. 1, a single point mooring system needs buoyancy for mooring, so the duct should be designed with enough bulk to act as ballasting tank. And some generating devices and power train could be placed in this space. The duct design was initiated considering the overall concept of the generating system.

3 DUCT DESIGN

The angle of duct was based on the previous studies. [3] Thin plate shape shrouded ducts were analyzed by CFD in 2012. And the optimal angle of nozzle and diffuser, 0.315radian had been defined. For the post research, 3 type ducts had been designed considering entire concept of single point moored TCP. Nozzle-diffuser type duct that has 11.2°of nozzle and diffuser angle showed the highest performance with 1.65 flow amplification factor. [5] And also, the CFD analysis for that nozzle-diffuser type duct including counter-rotating turbine were conducted like Fig. 2. However the turbine inside the duct blocked and disturbed the flow into the duct, and the turbine performance was not enhanced significantly. Therefore the study on modification for duct shape was conducted based on this previous CFD analyses. In this study, the nozzle-diffuser type duct was called to baseline duct.

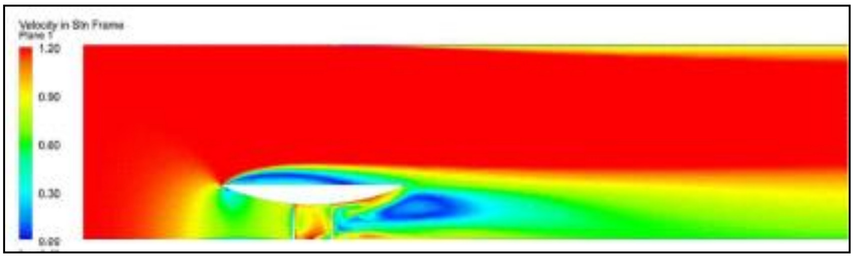


Fig. 2. CFD result of the baseline duct with turbine [5]

To improve the duct performance, 2 methods were considered. First method is to modify the diffuser angle. With using the shape of the baseline duct, several CFD analyses were carried out to investigate the performance of the duct with various diffuser angles. For the results, 5°case was defined as the optimal diffuser angle. That case showed the maximum flow amplification factor of 1.82. Another method is to modify the shape of outer surface to prevent separation near the inlet.

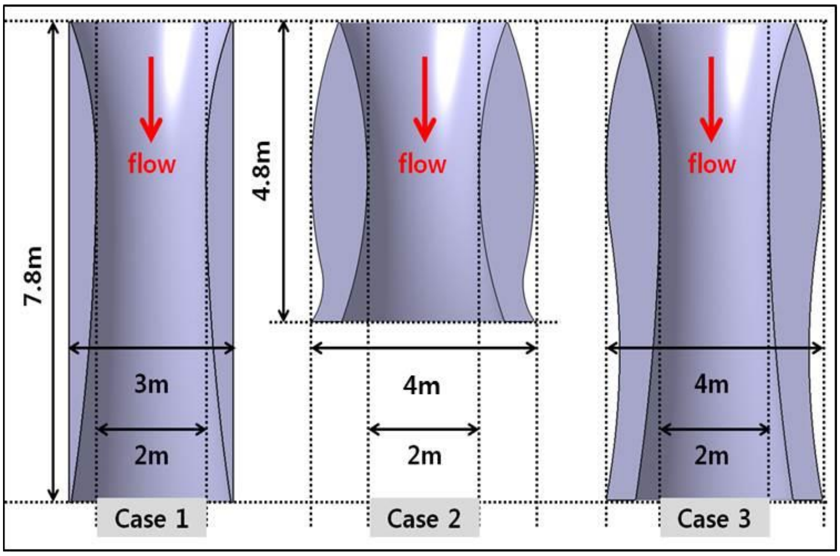


Fig. 3. 3-D duct design with CATIA V5R19

Therefore 3 modified ducts were designed based on the baseline duct shape. The modified duct shapes are shown in Fig. 3.

Case 1 has 5°of diffuser angle. And case 2 has curved surface to prevent separation observed in CFD analysis including tidal turbine. And both, modified diffuser angle and curved surface, were applied to case 3 to examine the combined effect on the duct performance. Also, case 2 and case 3 have cut outlet shapes to generate negative pressure behind outlet for suction effect.

4 CFD ANALYSIS

This research used the ANSYS CFX v13.0 commercial CFD code to simulate flow patterns around the three duct shapes. All analysis cases have the same external boundary dimensions as shown in Fig. 4, with different duct shapes in the inner domain.

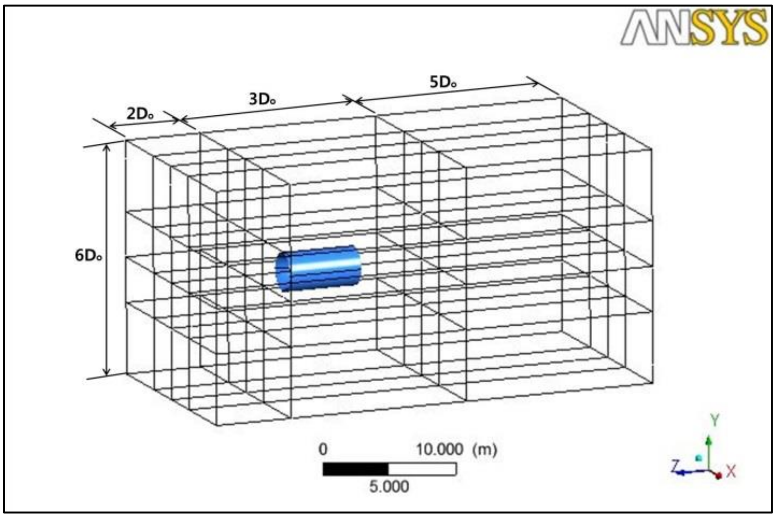


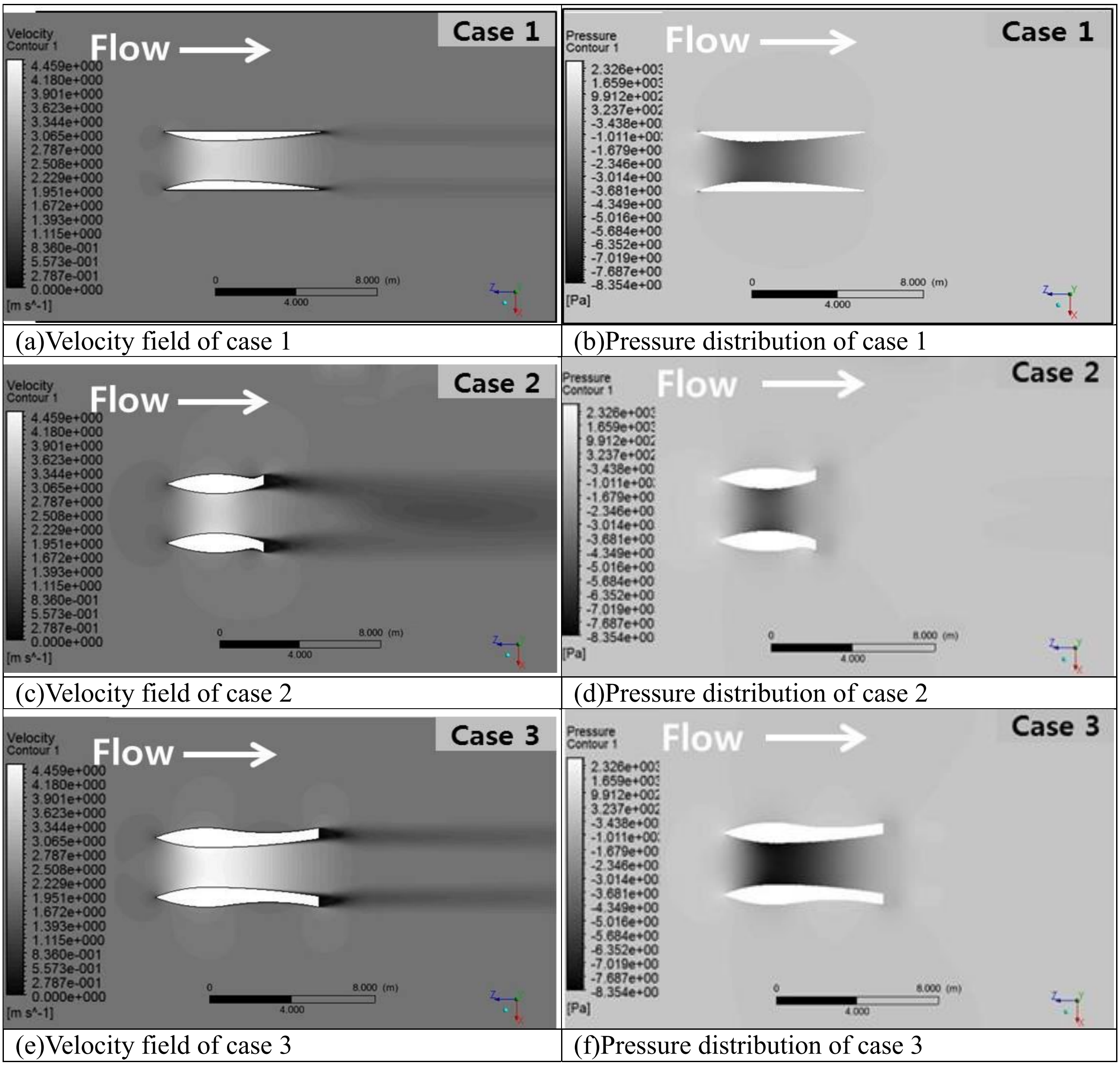
Fig. 4. External boundary dimensions

Grid generation was carefully carried out for smooth convergence and reliable results. The thickness of the near-wall grid layers was considered according to the application of the turbulence model, as was the aspect ratio of the mesh. In this simulation, a shear stress transport (SST) model, which requires a low y-plus value under 10 for reliable results, was used as the turbulence closure. A total of 2 million nodes were generated with tetrahedral and prism cells. Table 1 shows the computational grid information

Table 1. Analysis conditions

Description	*Analysis condition*
Working fluid	Water (1025kg/m3)
Inlet	Normal speed (2 m/s)
Wall	Stationary wall (no slip)

Outlet	Outlet (Relative pressure = 0 Pa)
Turbulence model	SST model



(a)Velocity field of case 1 | (b)Pressure distribution of case 1

(c)Velocity field of case 2 | (d)Pressure distribution of case 2

(e)Velocity field of case 3 | (f)Pressure distribution of case 3

Fig. 5. Flow characteristics around the each duct

Fig. 5 shows the characteristics around the duct from the CFD analyses. For all cases, flow velocities inside the duct were amplified more than baseline duct. And huge vortices were observed near the outlet in case 2 and case 3 by cut outlet shapes. Also the location where the maximum flow velocity was generated was found for each case. It may describe the flow pattern through the pressure distributions. The stagnation pressure near inlet decreased than baseline duct.

And the negative pressures were observed near the outlet in case 2 and case 3. These negative pressures can contribute to the duct performance with suction effects.

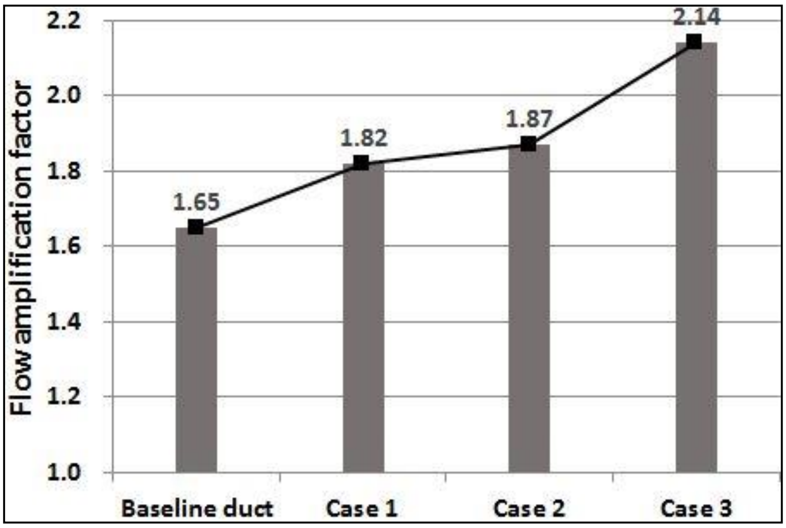


Fig. 6. Comparison of maximum flow amplification factor in the duct

Especially, the maximum flow amplification factor was 2.14 in case 3. Fig. 6 is comparison of maximum flow amplification factor for each case. From the CFD analysis, a remarkable improvement was found. From the baseline duct shape, the duct performance has been enhanced significantly through the modification. These flow amplification factors are the ratio of maximum velocity inside the duct and the upstream flow velocity.

5 EXPERIMENTAL VALIDATION

To validate the results of CFD, experiments were conducted in circulation water channel. 3 type duct 1/6 scaled mock-ups were manufactured as shown in Fig. 7. To measure the velocity inside the duct, acoustic doppler velocimeter(ADV) was used. And each duct mock-ups have several accessible slits to insert the ADV's stem.

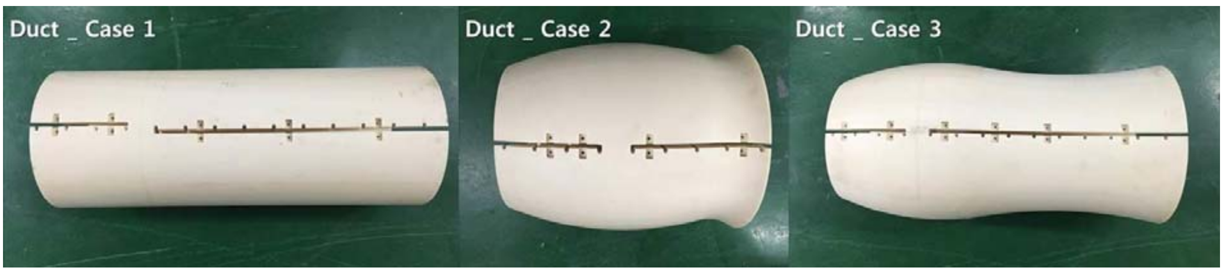


Fig. 7. 3 case mock-ups

The experiments were carried out with 1.0m/s upstream and 0.78m water depth condition. As shown in Fig. 8, the duct mock-up was supported by stainless steel structure.

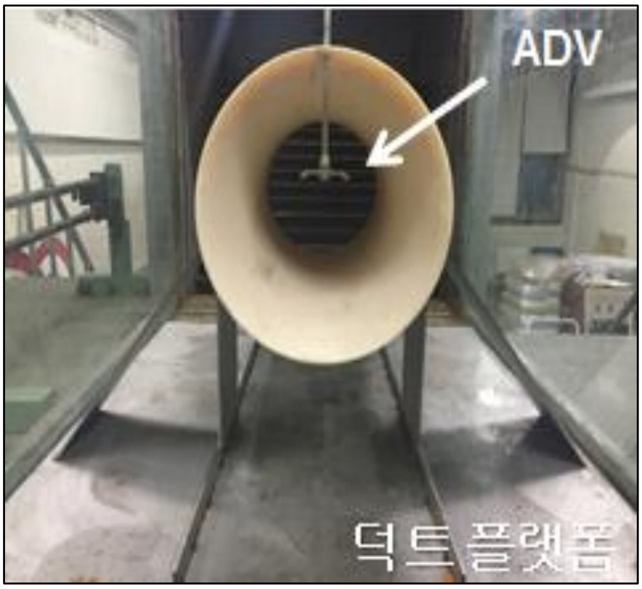


Fig. 8. Installed duct mock-up

Obtained experimental data was plotted in the Fig. 9.

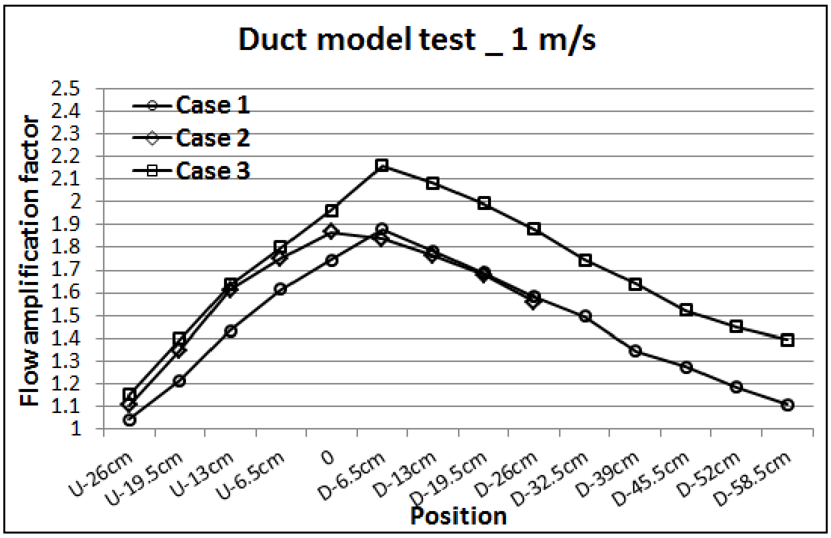


Fig. 9. Flow amplification factor according to location in the duct

0 point is where inner diameter is minimum, "U" means upstream direction and "D" means downstream direction. The maximum flow amplification factor of case 1 was 1.86. And for the case 2, it was similar value as 1.88. In case 3, the maximum flow amplification factor was 2.15. And also, it was found that the location where the maximum flow velocities were generated were different for case 1 and case 3.

Fig. 10~12 show the comparison of CFD and experiment results.

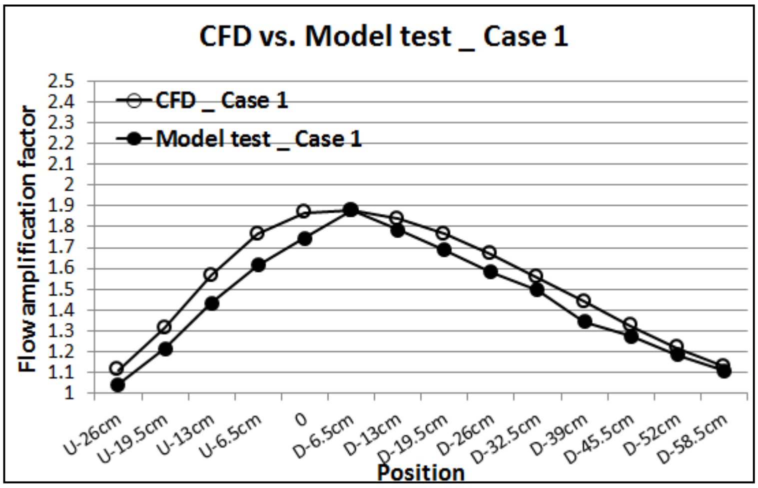


Fig. 10. Comparison of CFD and experiment in case 1

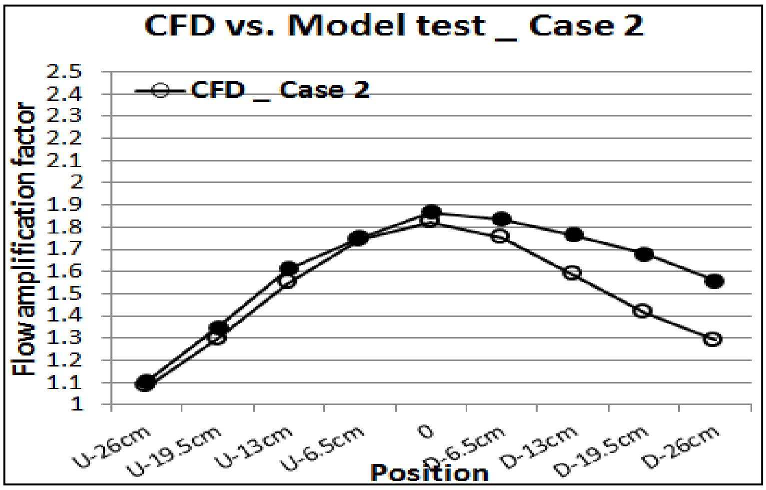


Fig. 11. Comparison of CFD and experiment in case 2

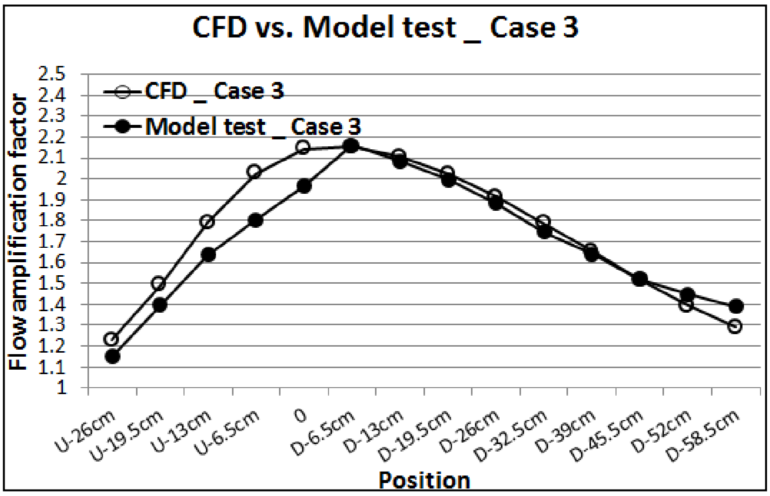


Fig. 12. Comparison of CFD and experiment in case 3

The maximum error was found in case 2, it was 17%. The error seems to be caused by strong vortices near the outlet of case 2. However, similar results were found for both CFD and experiment. The maximum flow amplification factor was 2.15 in case 3 as same with CFD result.

6 ECONOMIC IMPACT OF THE DUCT

It is expected to have a remarkable economic impact by using duct for tidal converter since it can enhance the output power. The Korean government is implementing the RPS (Renewable Portfolio Standard) policy with the REC (Renewable Energy Certificate) since 2012 to encourage the development of renewable energy technologies. For tidal current energy, weight factor of 2.0 was applied in the REC that is same with offshore wind power system. For this year, the average SMP (System Marginal Price) in Korea is 0.08USD per 1kWh, and the electricity providers can make an additional profit by trading the RECs. As the recent market price of 1REC is 83.11USD, the power company generating electricity from tidal current energy can be credited with double RECs.

If the 1MWh power was generated from the tidal current energy without duct structure, the providers can make the profit of 80USD from the sale of electricity and of 166.22USD from the sale of REC. As described above, case 3 duct can amplify the inflow velocity 2.15 times and can generate the electricity 9.94 times more. By using the duct system the providers can make the profit of 795.2USD from the sale of electricity and of 1,652.23USD from the sale of REC. As a result, the tidal current power device that the duct structure is applied is much more economical than the bared turbine device. The revenue according to the usage of duct structure was compared in Table 2.

Table 2. Comparison of revenue

From 1MWh production	*Description*	*Revenue (USD)*
Tidal Current Power Device Without Duct Structure	Sale of electricity	80
	Trade of RECs	166.22
Tidal Current Power Device With Duct Structure	Sale of electricity	795.2
	Trade of RECs	1,652.23

7 CONCLUSION

The duct application has proved the amplification of the flow velocity. And the amplification factors for various duct configurations were obtained in the CFD. Also, experimental validations were conducted to confirm the CFD analyses. In case 1, the maximum flow amplification factor was 1.86. And 1.88 in case 2 and 2.15 in case 3 were obtained.

The present research is focused on the duct effect without turbine to investigate detail effects and performance as the base study. The additional research of the duct effect including turbine installed inside is to be conducted later together with the flow analysis around the various duct configurations.

The economic impact of the duct application was reviewed to confirm the economic feasibility.

Finally this study is a preliminary research about the duct, so it may be reference and guideline to the next duct researches.

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On the nexus of energy use-economic development: A panel approach

António Cardoso Marques[1], José Alberto Fuinhas[1], Jorge dos Santos Gaspar[2]

[1] NECE-UBI and [1,2] University of Beira Interior, Management and Economics Department, Estrada do Sineiro, 6200-209 Covilhã, Portugal, amarques@ubi.pt

ABSTRACT

At a time when the major concern is the future of our planet, gains prominence the distinction between economic growth and economic development. Gross Domestic Product (GDP) is the indicator used to measure both, but is a very inefficient to evaluate development. The most prominent indicator as an alternative is the Index of Sustainable Economic Welfare (ISEW). The ISEW diverges from GDP namely by considering how the countries are using the resources, affecting environment and distribute the income available for the Society. In this paper, ISEW is used as a proxy of development to study energy consumption-economic growth nexus. The paper is focused to appraise if the traditional energy-growth nexus achievements reported in the literature remains unchanged when using a more suitable indicator to economic development the energy-growth traditional hypotheses are tested through a Panel-Corrected Standard Errors estimator, for annual data of twenty countries covering the period of 1995 to 2013. It is proven that the feedback hypothesis between economic growth-energy consumption and the growth hypotheses between sustainable development and renewable energy is present. Results also show that ISEW is not a perfect substitute of the GDP. As consequence, the traditional energy-nexus approach could leads to the implementation of policies to stimulate non-renewable energies and energy consumption that cause irreparable damage to the environment and put at risk the Planet future.

KEYWORDS: Energy consumption, Economic growth, Economic development, ISEW, PCSE

1. Introduction

Study only the goods and services consumption, distribution and production process are insufficient to evaluate countries sustainable development, which is the only way to ensure the future of the Planet. Sustainable development concept was arise for the first time in World Commission on Environment and Development (WCED, 1987) document, has a "development that meets the needs of the present without compromising the ability of future generations to meet their own needs", and thus is necessary to take into account three items: social, economic and environmental. Which was explicit in the "17 new Sustainable Development Goals" released in 25th September of 2015 by UN. To achieve those goals its essential necessary invest in education, health, suppress various inequalities types and mostly use natural resources efficiently.

World population is increasing, being actually 7.3 thousand millions, and expected to rise 1.5 thousand millions until 2030, the UN concern with use of earth resources and well-being became natural. This made draw up not only the 17 objectives referred to in the previous paragraph, but also reveal concerns about the measurement of countries well-being. Although this problem is just now being discussed more seriously, there are already some time ago several indexes that measure social well-being, such as the Human Development Index (HDI)) or Gross National Happiness (GNH), but only the Index of Sustainability and Economic Welfare (ISEW) created by Daly and Cobb in 1989, is established in the literature and takes into account the well-being and use of natural resources by each countries. Besides, that are taken into account components of inequality in income distribution, exchange of goods/services and investment in health or education by the Government. All this makes the ISEW the best indicator to measure sustainable development, because takes into account practically all the essential elements for achieve the goals set by the United Nations as essential to the future of our Planet and the generations who will live in it. These concerns are not taken into account in Gross Domestic Product, the most economic growth proxy use in scientific papers.

It is necessary to rethinking the way we want to measure countries economic development to actually being seen the well-being variation and nations affords to assure the Planet earth future. It is widely proven in literature that the rise of energy consumption is related with economic growth, which was necessary for improving our lifestyle, but in the XXI century, as point it out in 2015 UN Climate Change Conference, is necessary to look to energy consumption in a sustainable way.

Following that line of thought this paper compares ISEW, sustainable development proxy, with GDP, economic growth proxy and the relation of those two proxies with energy consumption. This paper has a central question: Are the usual results of the energy-growth (measured by GDP) nexus, found in the literature, valid when using a more suitable indicator to economic development? Therefore, the main paper objectives are: (i) assess the energy consumption impact on the sustainable development; (ii) appraise the different effects in ISEW from renewable and non-renewable energies; (iii) point out the differences between economic growth and sustainable development. For these purpose we study annual data for twenty countries covering the period 1995 to 2013. For achieve the main goals a panel data analysis was performed.

The results show differences between study energy nexus with ISEW and GDP. Energy produce by renewable sources are important to development measure by ISEW. On the contrary, one of the major drives to GDP growth are consumption of non-renewable energy sources, which makes ISEW a better indicator to measure countries efforts to preserve the Planet.

The remainder of the paper is organized as follows. Section 2 presents a literature review from ISEW and energy consumption nexus. Section 3 describes the data and methodology used. Section 4 shows the results. Section 5 discuses and interprets the results. Section 6 concludes.

2. Literature Review

There is a lack of empirical studies analyzing the nexus by focusing in the development instead of economic growth, and few with ISEW and GDP comparisons (Beça & Santos, 2014). For support this paper the literature review was divided in the ISEW, sub-section 2.1, relation between energy consumption and economic growth present in sub-section 2.2, the determinants of economic growth (2.3.1), and energy consumption (2.3.2).

2.1 The Index Sustainable and Economic Welfare

ISEW is new (1989) comparing to others indicators, so it construction is not completely defined in the literature. There are several components that are repeated in published works where this index was used, such as private consumption (Daly & Cobb, 1989) calculated by the adjustment of private consumption to the GINI Index. Other ISEW elements present in relevant publications are the public spending in health and education. Considered as positive for society, but only in 50% due to expenditures such as wages, inefficiency cost, investments in equipment and buildings. The fixed capital growth is also taken into account (Pulselli, Bravi, & Tiezzi, 2012) such as the unpaid work, which is calculated by the assumption that workers generate capital gains to the country in respective country's minimum wage (Menegaki & Tsagarakis, 2015). For the natural resources exploitation, Menegaki and Tsagarakis (2015) used the indexes of forest, minerals and fossil fuels derivatives created by the World Bank, allowing extension of database, time horizon and the number of countries considered.

2.2 Energy-Growth nexus

The causality relationship between economic growth and energy consumption has been widely explored, mostly testing four hypotheses (Ozturk, 2010): (i) feedback hypothesis, in which energy consumption causes economic growth and vice versa; (ii) neutrality hypothesis, assumes that energy consumption and economic growth are neutral from each other, so efficiency energy policies can be useful without product decreasing; (iii) growth hypothesis, specifies a unidirectional relationship from energy consumption to economic growth, therefore energy consumption diminishing affects negatively economic growth; and (iv) conservation hypothesis, states a unidirectional causality implying that an increase in the product causes an increase in energy consumption, but economic growth is not fully dependent from energy consumption. There is still the possibility that an increase of energy consumption cause an economic growth reduction (Fuinhas & Marques, 2013).

2.3 Determinants

2.3.1.1 Economic growth determinants

The principal factors used in our study potentially causing economic growth are labor, trade openness, inflation, energy and geographical area. Due to lack of data other factors like productivity and foreign direct investment are not taken into account. Gross capital formation is not part of the study because is an ISEW component and is utilization precluded the work results. For trade openness proxy is used imports *per capita* (IMPTPC) which widely proved that have a positive effects on growth, even in energy consumption studies (Al-mulali & Sheau-Ting, 2014). A higher value of imports *per capita* means a more openness of the economy. This implies better use from comparative advantage in trade, then a higher economic growth.

The number of employees is used as Labor proxy (EMP). This variable is used in several energy nexus articles (Soytas & Sari, 2003; Yildirim, Saraç, & Aslan, 2012; Bowden & Payne, 2009; Ghali, 2004). All having the same conclusion, i.e. a positive relation between employment and growth.

Consumer price Index (CPI) is computed like energy prices proxy (Bartleet & Gounder, 2010; Eggoh, Bangake, & Rault, 2011) based on the fact that all products prices depends from energy prices. In the model with GDP as dependent variable is not used, because is an inflation indicator. As known, inflation has a non-linear relation with Gross Domestic Product which diverges from the energy prices relation.

Energy influence in economic growth is tested by four variables: natural resources rents *per capita* (RENTSPC), energy imports *per capita* (EIMPTP), renewable (RESPC) and non-renewable energy (NRESPC) consumption *per capita*.

Energy imports determine the effect of the energy dependence on economic growth and sustainable development (Gan, Eskeland, & Kolshus, 2007). Is expected a negative impact in economic growth. Dependence from another country, turns control the prices a difficult task, mainly if that country have political and social instability. The relation with sustainable development it is expected positive, because countries more dependents from the outside tend to invest more in energy efficient policies and energy renewable production.

Natural resource rents *per capita* (forest, mineral, oil, coal, and gas) permits the valuation of the environmental impact for each country. It is expected a negative relation in ISEW and positive relation with GDP, due the monetary advantages.

Primary energy consumption is decouple in renewable energy consumption *per capita* (hydro, solar, wind and biomass), and non-renewable energy consumption (oil, coal, gas and nuclear) *per capita*. This was done in several studies proving a feedback hypotheses from the two different consumption sources to economic growth (Tugcu, Ozturk, & Aslan, 2012; Apergis & Payne, 2012). When studies are made with renewable energy as principal concern, the results are different, a negative effect on GDP (António C. Marques, Fuinhas, & Afonso, 2015) or a positive relation only for part of the countries studied (Bhattacharya, Paramati, Ozturk, & Bhattacharya, 2016) Thus that relationship is unpredictable in the model that will be computed in this paper.

There is a lack in literature from energy studies that use geographical area, but how is a time invariant variable is useful to distinguish countries. When area is bigger, countries have more potential for renewables production (Carley, 2009), therefore is expected a positive effect in sustainable development.

2.3.2 Energy consumption determinants

The principal energy consumption determinants seen in literature are urbanization level (URBAN), energy price, GDP, industrialization level and with less frequency energy security. Urbanization and industrial level are widely explored in energy studies with a consensual conclusion, a positive effect in energy consumption (Al-mulali & Sheau-Ting, 2014;York, Rosa, & Dietz, 2003).

In this work, as point out before, consumer price index is a proxy from energy prices as used in several articles (Bartleet & Gounder, 2010; Eggoh et al., 2011).

Energy imports is the energy security proxy (António C. Marques, Fuinhas, & Pires Manso, 2010). We predict that more dependence from energy imports cause additional looking for energy efficiency policy and leads to energy consumption decreasing. So for energy from fossil sources production (FPRODPC) the contrary is expected, since a more production diminishes dependence from the outside.

3. Data and Methodology

Annual data ranging from 1995 to 2013, for 20 countries around the world: Australia, Belgium, Brazil, Czech Republic, France, Greece, Hungary, Korea, Netherlands, New Zealand, Poland, Portugal, Slovakia, Spain, United States of America, Colombia, Peru, Romania, Thailand and Ukraine are used. Chosen taken into account the available data for the 12 indicators used to construct ISEW (table 1) and for the other 12 variables.

Table 1:
ISEW components

Component	Data Source	Calculation
Adjusted private consumption (+)	Household final consumption expenditure – World bank Gini index - Eurostat e SEDLAC	Household final consumption expenditure * (1- GINI Index)
Net capital growth (+/-)	World bank	Gross Capital Formation - Gross Capital Consumption
Health expenditure (+)	World bank	Public health expenditure * 0,5
Education expenditure (+)	World bank	Public education expenditure * 0,5
Unpaid work (+)	Number of unpaid workers- World bank Minimum wage- Ilostat	Number of unpaid workers * Minimum wage
Mineral depletion (-)	World bank	Ratio of the value of the stock of mineral resources to the remaining reserve lifetime (capped at 25 years). It covers tin, gold, lead, zinc, iron, copper, nickel, silver, bauxite, and phosphate.
Net forest depletion (-)	World bank	Calculated as the product of unit resource rents and the excess of round wood harvest over natural growth.
Energy depletion (-)	World bank	Ratio of the value of the stock of energy resources to the remaining reserve lifetime (capped at 25 years). It covers coal, crude oil and natural gas.
Carbon dioxide damage (-)	World bank	Carbon dioxide damage is estimated to be $20 per ton of carbon (the unit damage in 1995 U.S. dollars) times the number of tons of carbon emitted.

Comparison between ISEW and GDP is made by a graphic with median of both. (Fig 1). Then for energy nexus revisited in a sustainable way with four panel data models, thus avoiding autoregressive and causality models. These only check a relation between a variable with other once, not taken into account the growth classical facts that affect at the same time the economic growth and sustainable development. Small time span from available data is also inadequate to ensure autoregressive models viability. Thus for ISEW and GPD comparison and for the four energy-nexus hypothesis testing, is necessary to calculate four models (table 2).

Table 2

	Dependent variable	Independent variables
Model 1	LISEWPC	Economic growth determinants
Model 2	LGDPPC	Economic growth determinants
Model 3	LECOMPC	Energy consumption determinants (more LISEWPC)

Model 4 LECOMPC Energy consumption determinants (more LGDPPC)
Models description

All the variables are logarithmized to rescale the data and make the non-linear relations linear. Data sample has transformed in panel data form, which increase the observations number, bringing a higher viability to the study. Panel data can be performed under standard errors and residuals instability provided that are chosen right estimators.

It is done the Pesaran parametric test, Friedman semi-parametric test and Frees non-parametric test. All them to random and fixed effects, in order to detected cross-section dependence. The Wooldridge test to identified serial correlation and Wald modified test to recognize the group wise heteroskedasticity. If the three types of error composition are detected, Random/Fixed Effects Estimators are inefficient but can be performed the Feasible Generalized Least Squares (FGLS) and the Panel Corrected Standard Errors (PCSE). FGLS only can be use when the cross sections number (N) are smaller than the periods (T). Usually with time-invariant variables (LAREA in this paper), the Fixed-Effects Vector Decomposition (FEVD) procedure is used. FEVD is calculated like if time-invariant variable were an instrumental variable (IV). Without justification for having an IV, from the FEVD procedure arises wrong conclusions (Breusch *et al.,* 2011)

4. Results

To a first comparison between ISEW and GDP is seen in graphic of figure 1 with the mean evolution from the two indicators in the 20 countries considered in this paper.

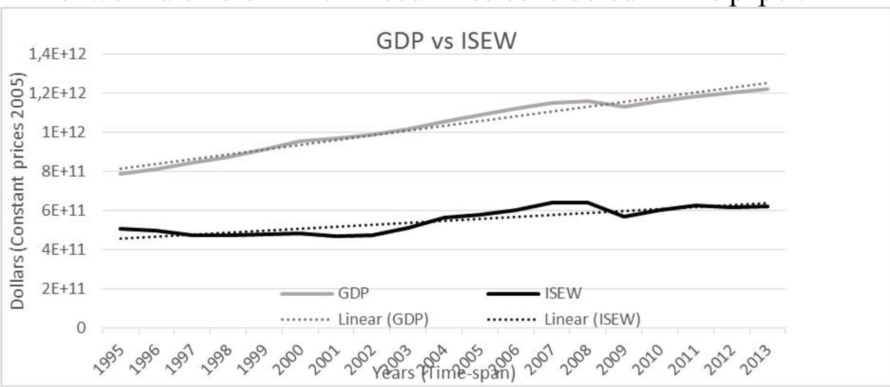

Fig. 1-Comparation between countries GDP mean and countries ISEW mean

It can be seen in graph an increase in GDP and ISEW since 1995 until 2013. From 1995 to 2002 there was an ISEW decline, on the contrary GDP grew. 2008 crisis, despite being of financial character, also was reflected in the ISEW value. GDP demonstrate more tendency to growth than ISEW in the analyze time period.

The comparison is also done through energy-consumption nexus with panel data constituted by 20 countries. Due to differentiated characteristics of the countries is expected a different variations in economic growth, what is translated in panel heteroskedasticity. Therefore, it was computed a modified Wald test, where the null hypotheses is rejected, supporting the presence of heteroskedasticity. Panel data must be treated carefully due the fact usually have complex error structures, thus was made Wooldridge, Pesaran, Frees and Friedman tests and in all of them were rejected the null hypotheses, consequently was proved contemporaneous autocorrelation and cross-section dependence.

Results from specification tests demonstrate contemporaneous autocorrelation, group wise heteroskedasticity, and cross-section dependence for all four models. Coupled with the fact that FGLS just work for panels with T>N and we have 20 countries and 19 years, the PCSE is the more suitable estimator. This allows us to have various forms to estimate the model, besides the traditional pooled OLS model (OLS), with first-order autocorrelation and a specific coefficient AR (1) different to each country (Psar1); with first-order autocorrelation but the same AR(1) coefficient for all countries (Ar1); the independent (Ind) that specifies a no autocorrelation but correlation over countries; and with AR(1) common to all countries and they heteroskedasticity level errors (Normal). The four models can be seen in Table 3, 4, 5 and 6.

Table 3:
Model 1

Dependent variable - LISEWPC					
Independent variables	OLS	PCSE			
		Normal	Psar1	Ar1	Ind
LEMP	0.4454***	0.4454***	0.3990***	0.4003***	0.4454***
LNRESPC	-0.2490***	-0.2490***	-0.1920***	-0.1604***	-0.2490***
LRESPC	0.2864***	0.2864***	0.1335***	0.1603***	0.2864***
LCPI	-0.7775***	-0.7775***	-0.7841***	-0.8136***	-0.7775***
LRENTSPC	-0.0318**	-0.0318***	-0.0236*	-0.0268**	-0.0318***
LIMPTPC	0.9217***	0.9217***	0.7582***	0.8264***	0.9217***
LAREA	-0.0582***	-0.0582***	-0.0238	0.0107	-0.0582***
LEIMPTPC	0.0581**	0.0581***	0.0634**	0.0635**	0.0581***
Observations	379	379	379	379	379
R2	0.9982	0.9982	0.9950	0.9921	0.9982

Note: ***, **, *, denote significance at 1, 5 and 10% significance levels, respectively.

Table 4:
Model 2

Dependent variable - LGDPPC					
Independent variables	OLS	PCSE			
		Normal	Psar1	Ar1	Ind
LEMP	0.6321***	0.6321***	0.4095***	0.4469***	0.6321***
LNRESPC	0.2630***	0.2630***	0.3950***	0.3523***	0.2630***
LRESPC	-0.0116	-0.0116	0.0238*	0.0026	-0.0116
LRENTSPC	-0.1301***	-0.1301***	-0.0491***	-0.0464***	-0.1301***
LIMPTPC	1.1014***	1.1014***	0.6775***	0.6621***	1.1014***
LAREA	0.4681***	0.4681***	0.5047***	0.4579***	0.4681***
LEIMPTPC	-0.2384***	-0.2384***	-0.0230	-0.0061	-0.2384***
CONS	3.2993***	3.2993***	13.4174***	12.6086***	3.2993***
Observations	379	379	379	379	379
R2	0.9291	0.9291	0.9997	0.9981	0.9291

Note: ***, **, *, denote significance at 1, 5 and 10% significance levels, respectively.

Table 5:
Model 3

Dependent variable - LECOMPC					
Independent variables	OLS	PCSE			
		Normal	Psar1	Ar1	Ind
LISEWPC	-0.0992*	-0.0992***	-0.0197	-0.0332	-0.0992***
LINDPC	0.4099***	0.4099***	0.6433***	0.5363***	0.4099***
LURBAN	0.3562***	0.3562***	-0.0118	0.2159**	0.3562***
LCPI	-0.1785***	-0.1785***	-0.1448***	-0.1228***	-0.1785***
LFPRODPC	0.0764***	0.0764***	0.0927***	0.0623***	0.0764***
LEIMPTPC	0.3120***	0.3120***	0.1147***	0.1126***	0.3120***
CONS	-11.1541***	-11.1541***	-15.1629***	-14.5787***	-11.1541***
Observations	304	304	304	304	304
R2	0.8313	0.8313	0.9997	0.9939	0.8313

Note: ***, **, *, denote significance at 1, 5 and 10% significance levels, respectively.

Table 6:
Model 4

Dependent variable - LECOMPC					
Independent variables	OLS	PCSE			
		Normal	Psar1	Ar1	Ind
LGDPPC	0.0709***	0.0709***	-0.0378	0.0511***	0.0709***
LIVAPC	0.2261***	0.2261***	0.6541***	0.4620***	0.2261***
LURBAN	0.3816***	0.3816***	0.3816***	0.3816***	0.3816***
LCPI	-0.1242***	-0.1242***	-0.1153***	-0.1000***	-0.1242***
LFPRODPC	0.0814***	0.0814***	0.0666***	0.0636***	0.0814***
LEIMPTPC	0.3192***	0.3192***	0.0971***	0.0971***	0.3192***
CONS	-12.5539***	-12.5539***	-15.0243***	-15.8206***	-12.5539***
Observations	304	304	304	304	304
R2	0.8401	0.8401	0.9997	0.9945	0.8401

Note: ***, **, *, denote significance at 1, 5 and 10% significance levels, respectively.

The main results discovery on model 1 are the unexpected negative effect from land area in ISEW, the positive relation between energy from renewable source and ISEW and the negative influence from the non-renewable energy, although expected is a very important remark. In Model 2 the unanticipated negative influence from the natural rents in GDP and the insignificance renewable energy stands out. From the model 3 and 4 arise an unexpected positive effect from energy imports in primary energy consumption. Model 3 point it out a non-found in literature negative influence by the ISEW in primary energy consumption.

5. Discussion

The models 1 and 2 allow the comparison between ISEW and GDP. The positive effect from energy imports in ISEW reveals an importance that energy efficiency and own energy production has in ISEW. The increase of energy imports leads to a decreasing in GDP because surges exposes to exterior, what brings costs, principally with political and social instability.

Land area is a time invariant measure making is analysis mostly cross sectional. Larger countries have a unexpected less ISEW growth for having more natural resources and energy economy base on that resources exploration and that don't shifts in a moment. Thus time span study is too short to see all country energy policy change, especially when in part of that time sustainability measures and renewable energies are very expensive and inefficient. Geographical area has positive effect in GDP, due to panel study with lager and faster growers like United States of America, France, Brazil and Australia.

As expected natural resources have a negative influence in ISEW due the environmental impact and difficulties cause in a sustainable growth. On the contrary the same sign was unpredictable in GDP which seems to be a resource cause effect. On the one hand the lack of diversification in explored resources which brings more exposure to external shocks, being them environmental or financial. For the other an economy based on that resources exports leads soon or later to a foreign exchange rates increase which brings competitive loss and sequentially an economic crisis.

Imports from goods and services have approximately the same effect in model 1 and 2, showing how important is trade openness. In the ISEW case still have the effect that trade liberalization be able to shift pollution activities from developed countries with more production cost, like environmental taxes, to poor countries.

Growth Hypothesis is confirmed for GDP and ISEW. The first with non-renewable energies and the second with renewable energies. Non-renewable energies still are more financially rewarding but undesirable to sustainable development (negative effect in ISEW).

Model 3 and 4 confirms that energy prices has a negative effect in energy consumption and an increase of houses, transports, cities and industries are important too. The energy consumption grows with more energy imports, which suggests looking for better prices in the outside and not just only for insufficient local production.

The positive effect that growth of GDP has in energy consumption settles the traditional feedback hypothesis, on the contrary ISEW growth effect is relativity new. The energy consumption increase can leads us to economic growth but with environmental damages.

6. Conclusion

It is applied panel data with PCSE to study energy nexus in a sustainable way (ISEW) and compare to economic growth (GDP) for 20 countries between 1995 and 2013.

In this paper stands out same differences between ISEW and GDP. ISEW can measures energy efficient, damages on environmental and the way natural resources are explored while GDP focus in financial relations and measures.

The traditional energy nexus conclusions are different that the ones with ISEW. Feedback Hypothesis is not confirmed. Indeed, there is a negative effect from ISEW growth to energy consumption. So it was founded that energy consumption increasing is financially rewarding but can put at risk the Planet future. Growth hypothesis was settled for ISEW with renewable energies and for GDP with non-renewable energies. Thus renewable energies are important to sustainable development but still inefficient, what makes difficult persuade countries for is production.

International agencies should take into account ISEW not as GDP perfect substitute, but as complementary. Witch might raise the energy renewables penetrability and respect for natural resources. It should be used to control commitment to international environmental treaties by the countries.

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Applying insights from ecological economics to macroeconomic growth modeling with the CES production function

João Santos[1], Matthew K. Heun[2], Paul Brockway[3],
Marco Sakai[3], Tiago Domingos[1], Randall Pruim[4]

[1] MARETEC – Marine Environment and Technology Center, Environment and Energy Scientific Area, Department of Mechanical Engineering, Instituto Superior Técnico (IST), University of Lisbon, Avenida Rovisco Pais, 1 1049-001, Lisbon, Portugal, joao.dos.santos@tecnico.ulisboa.pt, tdomingos@tecnico.ulisboa.pt
[2] Engineering Department, Calvin College, Grand Rapids, MI 49546, USA, mkh2@calvin.edu
[3] Sustainability Research Institute, School of Earth and Environment, University of Leeds, Leeds LS2 9JT, United Kingdom, P.E.Brockway12@leeds.ac.uk
[4] Mathematics & Statistics Department, Calvin College, Grand Rapids, MI 49546, USA, rpruim@calvin.edu

ABSTRACT

Aggregate production functions play a key role in macroeconomic models that inform government policies. A recent trend is towards Constant Elasticity of Substitution (CES) functions, which provide greater flexibility by generalizing the Cobb-Douglas to allow for constant non-unity elasticities of substitution, and time-varying output elasticities. In core mainstream growth models, aggregate production functions are generally used under neoclassical assumptions, taking each factor's output elasticity to be proportional to its respective observed cost share (i.e. the "cost share principle"), while disregarding the contribution to growth of energy or qualitative differences among inputs. Alternatively, ecological economics provides insights as to how inputs to production should be measured, and how energy should be included in a production function framework.

Based on such insights, we adopt a systematic approach to investigate the impact from several modeling choices framed by ecological economics on CES models. Namely, we contrast the assumption of the cost share principle with statistically estimated output elasticities, while also assessing the impact of: a) including energy as a factor of production; b) quality-adjusting factors of production; c) the nesting structure in three-factor CES models. No single study has tackled all these issues in a systematic manner. Using empirical data for the UK and Portugal for the time-period 1960-2009, we test separately and in combination the effects of these four design choices.

Results are reported in terms of the Solow residual, fitting residuals, and time-varying output elasticities. Precision of estimated parameters is assessed through statistical resampling analysis. Two key results are found. First, in each country, the best-fitting ecologically framed solution reduces the Solow residual by more than half compared to a standard neoclassical model. Second, choices of CES function structure and inputs have a substantial impact on parameter estimates. These results imply that the CES function allows greater flexibility but also exhibits greater dependence upon choices made by the modeler.

KEYWORDS: Constant Elasticity of Substitution, Solow residual, cost share, aggregate production function, partial output elasticities

1 INTRODUCTION AND BACKGROUND

1.1 Aggregate production functions

Aggregate production functions (APFs) seek to describe economic output via factors of production, such as capital, labor, energy, and materials. Historically, the most commonly used APF has been the Cobb-Douglas (C-D) function:

$$y = \theta A k^{\alpha_k} l^{\alpha_k}, \text{ with } A = e^{\lambda t}; \qquad (1)$$

Economic output y is written as a function of the factors of production capital k, and labor l. The parameters θ, α_k, and α_l are, respectively, a scale parameter and output elasticities for capital and labor. Total factor productivity A is written as an exponential function of time t, where λ represents the exogenous Solow residual. All historical data (y, k, l, and later energy e) are normalized, meaning aggregate values are indexed relative to an initial year. Time t is normalized by difference relative to an initial year t_0. After normalizing, θ is expected to be near unity. Greek letters θ, λ, α_k, α_l, and later α_e, δ_1, δ, ρ_1, and ρ) represent parameters determined by fitting the model to historical data.

A drawback of the C-D function is that the elasticity of substitution between factors of production is assumed to be unity. To allow for other values of the elasticity of substitution, the Constant Elasticity of Substitution (CES) APF was developed as an extension of the C-D production function (Arrow et al., 1961).

$$y = \theta A[\delta_1 k^{-\rho_1} + (1 - \delta_1) l^{-\rho_1}]^{-1/\rho_1}, \text{ with } A = e^{\lambda t}; \qquad (2)$$

In the CES function, δ_1 (and later δ) provides the weighting for the factors of production, and ρ_1 is a measure of substitutability between k and l. The elasticity of substitution ($\sigma_1 = 1/(1 + \rho_1)$) is constant with respect to time. Equation (2) assumes Hicks-neutral technical change (A augments all factors of production. If $\rho_1 = 0$, and therefore $\sigma_1 = 1$, the CES production function simplifies to the C-D production function.

Because the substitutability and complementarity of factors of production vary from one economy to the next, from factor to factor within an economy, and through time, the CES function is better suited to describe economic output than the C-D function. However, the increased suitability of the CES function comes at a cost: with more parameters and a non-linear structure (in logarithmic space), the CES function is more demanding, in terms of both fitting technique and computational resources, than the C-D function when estimating parameters from historical data. Even so, the CES function has joined the C-D function as a popular option for macroeconomic growth modelers today (Sancho, 2009; Sorrell, 2009; Koesler & Schymura, 2012; Temple, 2012).

1.2 Insights from ecological economics

For this paper, insights from ecological economics guide our thinking and shape the modeling choices evaluated in our empirical analysis.

Although energy is absent from most mainstream economic models (Aghion & Howitt, 2009), the field of ecological economics considers energy to be at least as significant as capital and labor for economic production and human development. By embedding the economy within the larger environmental system and accounting for energy transfers between the two, ecological economists argue that economic thinking and practice should be grounded in physical reality, namely the laws of thermodynamics. Thus, the first insight from ecological economics is that energy should be considered as a factor of production.

The second insight from ecological economics addresses energy and the Cost Share Principle (CSP). As Ayres et al. (2013) state, energy is absent from neoclassical growth models for three reasons: an accounting identity; a historically observed stylized fact, and an equilibrium condition arising from a simplifying income allocation theorem.

The identity, commonly adopted in statistical databases and national accounts, is that GDP is defined in the income approach as the sum of payments to capital and labor. The stylized fact is that historically, shares of these payments in total GDP have remained nearly constant over time, with the cost share of labor representing approximately 70\% of total GDP and the cost share of capital accounting for the remaining 30\%. Finally, a cost share theorem (CST) states that if (a) the Cobb-Douglas model correctly models the effects of some factors of production on economic output, (b) there is perfect competition, and (c) the economy is at equilibrium with no surplus or scarce resources, then the following cost share principle (CSP) holds: the cost share of each factor of production is equal to its output elasticity (which in the Cobb-Douglas model is a constant).

Mainstream economics justifies its exclusion of energy as a factor of production as follows: when energy's small (according to the stylized fact) or zero (according to the accounting identity) cost share is equated to output elasticity (by the CSP), the output elasticity of energy is negligible or zero, and energy terms are eliminated from growth models.

However, the ecological economics literature reveals that the assumptions leading to the CSP are untenable. Kümmel and others (Kümmel et al., 2008; Kümmel & Ayres, 2010; Kümmel, 2013) show that the CSP is valid only for economies comprised of profit-maximizing firms in the absence of technological constraints – conditions that are seldom, if ever, present. Kümmel's work implies that a different approach to determining output elasticities is needed: they cannot be equated *a-priori* to cost shares. A standard approach is to estimate economic growth model parameters (including output elasticities) by fitting models to historical data. Thus, the second insight from ecological economics is that the CSP should be rejected and output elasticities should be determined by fitting statistical methods. For this paper, our approach will be to evaluate and compare the effect of rejecting (or not) the CSP in economic growth models.

After deciding that energy should be included as a factor of production and after rejecting the CSP, another question arises: what mathematical form should the production function take? By rejecting the CSP, any justification for assuming that output elasticities are constant with respect to time (as in Cobb-Douglas models) is removed. Indeed, in real economies output elasticities may change as the structure of the economy evolves and as technological constraints on production ebb and flow. Because output elasticities are constant with respect to time in the Cobb-Douglas production function (Equation (1)), rejecting the CSP leads away from Cobb-Douglas models. A common APF that provides time-varying output elasticities is the CES production function, the focus of this study.

When extending the two-factor CES production function (Equation (2)) to include energy, the form of the equation is in question. Specifically, the *nesting structure* of the factors of production is mathematically arbitrary. And, in our experience, parameter estimates may differ significantly depending on the nesting structure employed. Unfortunately, few studies methodically assess the effect of nesting structure. Kemfert (1998), Van der Werf (2008), and Shen & Whalley (2013) provide exceptions that prove the rule.) In the literature, nesting structure is usually selected based on theoretical considerations. In this paper, several nesting structures will be evaluated and assessed empirically.

Finally, a third insight from the ecological economics literature involves the quantification, or measure, of energy. For context, it is helpful to first discuss measures of capital and labor. Most empirical studies of economic growth typically account for the *quantity* of capital and labor as the only two factors of production with unadjusted measures such as monetary value of capital and work hours (Rusek, 1989; Finn, 1995; Chow & Li, 2002). However, not all capital and labor are equally productive: different capital assets provide different services to economic production, and skilled workers are more productive than unskilled ones.

In the relevant literature, there are studies that consider quality-adjusted labor (e.g., adjusting work hours by educational indexes) and quality-adjusted capital (measuring the productive effect of capital stocks as capital services), with the former (Hall & Jones, 1999; Vouvaki & Xepapadeas, 2008) being more common than the latter (Dougherty & Jorgenson, 1996; Hajkova & Hurnik, 2007). Indeed, accounting for capital services is a newer field of study, and Inklaar (2010) suggests significant measurement issues remain, such as the choice of the rates of return. Work continues in academia (Barro & Lee, 2013) and government to develop consistent datasets of capital services.

In the ecological economics literature, Ayres and Warr (Ayres & Warr, 2005; Warr et al., 2010; Ayres & Warr, 2010; Ayres et al., 2013) argue that the energy factor of production should be accounted at its point of use in an economy (useful work) as opposed to the point of extraction from the biosphere (primary energy) or at the point when it is sold to final consumers (final energy), because useful work is closer to productive processes and, therefore, more closely correlated to economic activity. From a thermodynamic point of view, the quantification of energy as useful work makes sense: it takes *physical work at the point of energy dissipation into heat* to extract and transform raw materials, fabricate goods and generate services, distribute products, and consume and dispose goods and services in a real economy. Useful work can be seen as a quality-adjusted measure of energy, similar to education-adjusted labor and capital services. Thus, the third insight from ecological economics is that useful work provides a quality-adjusted measure of energy.

For this paper, we consider both unadjusted and quality-adjusted measures for capital and labor, and we evaluate and compare the effects of both these measures on macroeconomic growth modeling. Inspired by ecological economics, we consider both unadjusted (primary energy) and quality-adjusted (useful work) measures of energy, too. Hence, we evaluate the effect of quality-adjusting all factors of production: capital, labor, and energy.

1.3 **Approach**

Few studies examine any of the modeling choices discussed above, and none to date has examined them all together. Thus, the time is right for a thorough, detailed, and careful evaluation of the CES production function, inspired by ecological economics considerations. The remainder of this paper performs this assessment by investigating the effects of four modeling choices: (1) rejecting (or not) the cost-share principle (CSP); (2) including (or not) energy as a factor of production; (3) quality-adjusting (or not) the factors of production, and (4) CES nesting structure.

The effects of the four modeling choices are discussed in subsequent sections. To perform these assessments, we utilize historical data for Portugal and the UK for the time period 1960--2009. Furthermore, we use statistical resampling on one CES production function – $(kl)e$ nesting with quality-adjusted factors of production – to give an indication of the precision with which CES parameters can be estimated. We know of no previous studies that perform a similarly comprehensive evaluation of the CES production function.

2 METHODS AND DATA

As motivated above, we work within a Constant Elasticity of Substitution (CES) production function framework. We also use an exponential-only production function as a reference model. For both, we estimate model parameters using ordinary least squares (OLS) with unadjusted and quality-adjusted factors of production.

2.1 Production functions

2.1.1 Exponential production function (reference model)

We define an exponential-only reference model for economic growth in Equation (3).

$$y = \theta A, \text{ with } A = e^{\lambda t}; \qquad (3)$$

The reference model provides an estimate of the overall economic growth rate (λ) for the economy.

2.1.2 CES production function

The CES production function shown in Equation (2) includes two factors of production, capital (k) and labor (l). Extending to three factors of production can be accomplished through nesting. Equation (4) augments Equation (2) with energy (e), in a $(kl)e$ nesting structure, as is common in the literature:

$$y = \theta A\left\{\delta[\delta_1 k^{-\rho_1} + (1-\delta_1) l^{-\rho_1}]^{\rho/\rho_1} + (1-\delta)e^{-\rho}\right\}^{-1/\rho}, \text{ with } A = e^{\lambda t}; \qquad (4)$$

Note that Equation (2) is a degenerate form of Equation (4) with $\delta = 1$ and ρ undetermined. Two other nestings of the factors of production – $(le)k$ and $(ek)l$ – are possible with a three-factor CES function. Each of the CES functions assumes constant returns to scale. As discussed above, output elasticities (α) for the CES function are not constant; rather, they vary with factors of production k, l, and e over time. It can be verified that $\alpha_k + \alpha_l + \alpha_e = 1$ for all nests.

The cost-share principle (CSP) asserts that output elasticities for factors of production are equal to cost shares in the economy. Historically, cost shares for capital and labor vary little over time and in CD models, the output elasticities are also constant. However, unless the CES function collapses to a CD function (i.e., $\rho_1 \to 0$ and $\rho \to 0$), output elasticities will depend on the values of k, l, and e.

As discussed above, applying the CSP usually means that energy is neglected as a factor of production because of its relatively small cost share. So when we refer to a CES model that adheres to the CSP, we mean a CD model with capital and labor as the only factors of production (Equation (1)) and with α_k and α_l fixed and determined by their (approximately constant) historical values.

2.2 **Parameter estimation**

To estimate values of parameters for the reference and CES models, we use an ordinary least squares (OLS) approach. The objective of the OLS analysis is minimization of the sum of squared errors (SSE):

$$SSE = \sum_i r_i^2 \quad (7)$$

Where $r_i = \ln(\frac{y_i}{\hat{y}_i})$ is i^{th} residual (all models assume multiplicative errors), and $\hat{y}_i$ is the fitted value for economic output at time t_i.

In the reference model, all economic growth is attributed to the Solow residual. On the other hand, it is not necessarily true that CES models will exhibit lower SSE than the reference model. The CES production functions have more parameters, but there is no set of parameter values estimates that eliminates the factors of production from the CES models, thereby reproducing the reference model.

If the factors of production are poorly correlated to output, SSE may be higher for a CES model than for the reference model. Parameter estimates for all models were obtained using the `R` package `micEconCES` (Henningsen & Henningsen, 2011) for CES models, and standard linear model routines for other models, but used customized code to fit all boundary models explicitly and select from these models the one that minimized SSE while satisfying the constraints of the parameter space.

Determining the precision of estimates for CES parameters is important but challenging. It is quite possible for substantial changes in a CES model parameter to have a relatively modest effect on the objective function that is determining the parameter estimates (in this case, SSE).

The usual methods for quantifying the precision of parameter estimates using standard errors, confidence intervals, and p-values rely on an asymptotic theory that applies on the interior of a parameter space and assumes independence of error terms. It can be difficult to provide an *a priori* justification for the use of asymptotic results or to correctly adjust for sample size or other potential violations of the model assumptions. Boundary issues may arise when estimated parameters lie on or near a boundary of the (the economically meaningful portion of) parameter space or when the hypothesis of interest lies on the boundary. In an investigation of whether energy is important, for example, in the $(kl)e$ nesting, we may consider the null hypothesis that $\delta = 1$ (so energy is not a meaningful factor of production). While there is an asymptotic theory for dealing with such cases (see e.g., Molenberghs & Verbeke, 2007), the distributions are in general more complicated – mixtures of chi-squared variates – and the precise mix may be difficult or impossible to determine analytically.

For this paper, we used naive residual resampling as a way to estimate the precision of parameter estimates. This approach creates simulated data sets using the fit from the original data perturbed by random noise generated from the residuals of that fit. The model is then refit to each of these resampled data sets. Variability in the parameters estimates from these resampled data sets is used as an indication of the precision of the original estimates.

2.2.3 Data

Our empirical analysis focuses on Portugal and the United Kingdom, for the 50-year period 1960-2009. This avoids economic shocks associated with World Wars I and II, and allows us to use official international statistics that generally go back only as far as 1960.

Economic output is quantified as gross domestic product (GDP) at constant prices in 2005 USD from Penn World Tables (PWT8.1, 2015). Capital, labor, and energy are not homogeneous, and any measure that fails to account for qualitative differences among these factors of production will lead to a less precise quantification of their effective contribution to output. Hence, we adopt both unadjusted and quality-adjusted measures for capital (da Silva & Lains, 2013; Oulton & Wallis, 2015), labor (PWT8.1, 2015), and energy (Serrenho et al., 2016; Brockway et al., 2014) inputs. Historical annual cost shares associated with capital and labor can be computed from data available at the European Commission's Annual Macro-Economic Database (AMECO).

3 RESULTS AND DISCUSSION

3.1 Parameter estimation results

An outcome of the parameter estimation process is estimates for each parameter in each model. The following subsections present the parameters graphically and interpret the results.

3.1.1 Solow residuals and SSE

Figure (1) shows Solow residuals (λ) and sum of squared errors (SSE) for all models. Vertical and horizontal grid lines show λ and SSE, respectively, for the reference model.

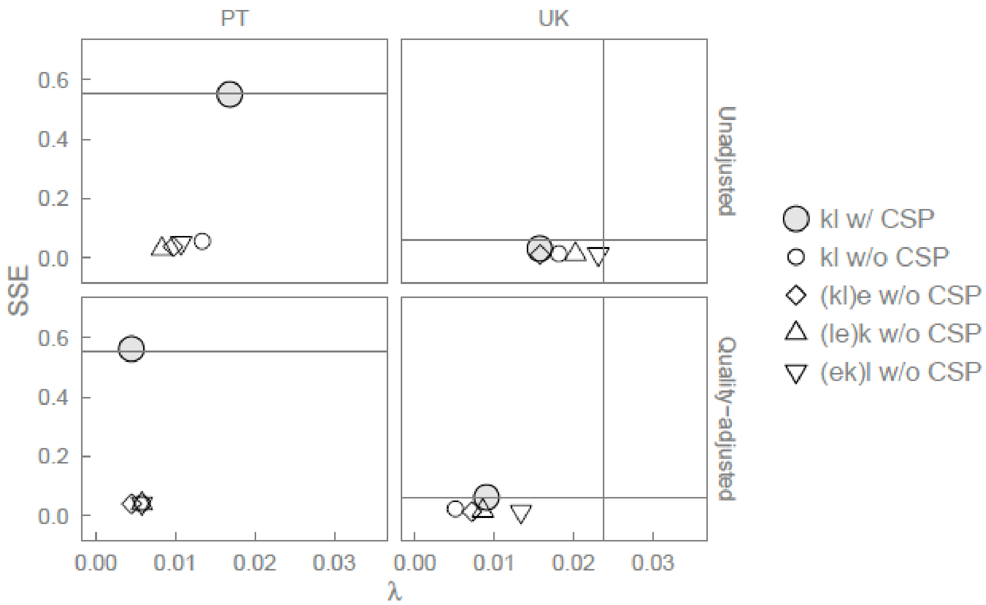

Figure 1 - Solow residual (λ) and SSE for all models.

Several implications can be drawn from the discussion of the effects of modelling choices on goodness of fit and the Solow residual.

First, goodness of fit should not be the primary criterion for modelling choices. After rejecting the cost share principle, there is little differentiation among the models in terms of SSE.

Second, use of quality-adjusted factors of production is important for reducing the Solow residual. Measuring factors of production closer to the productive act leaves less economic growth unexplained.

Third, we speculate that including energy in the CES production function may not be important for reducing Solow residual, because energy is complementary to capital. Further work on the dynamics of energy vis-a-vis capital and labor and elasticities of substitution among the factors of production is needed.

Finally, if energy is to be included in the CES production function, there is some indication that the $(kl)e$ nesting is preferred on the basis of reducing Solow residual relative to other nests. Other reasons for selecting the $(kl)e$ nest may also be important. For example, this nesting is the only option for analysing energy relative to the classical factors of production, capital and labor. And, Saunders (2008) indicates that it is the only "rebound flexible" version of the CES production function.

In summary, evidence from Portugal and the UK shows that more of economic growth can be explained endogenously by the CES production function when the cost share principle is rejected, factors of production are quality-adjusted, and the $(kl)e$ nesting is employed, if energy is included.

3.1.2 Output elasticites

Figure (2) shows the variation of output elasticities over time for all modeling choices.

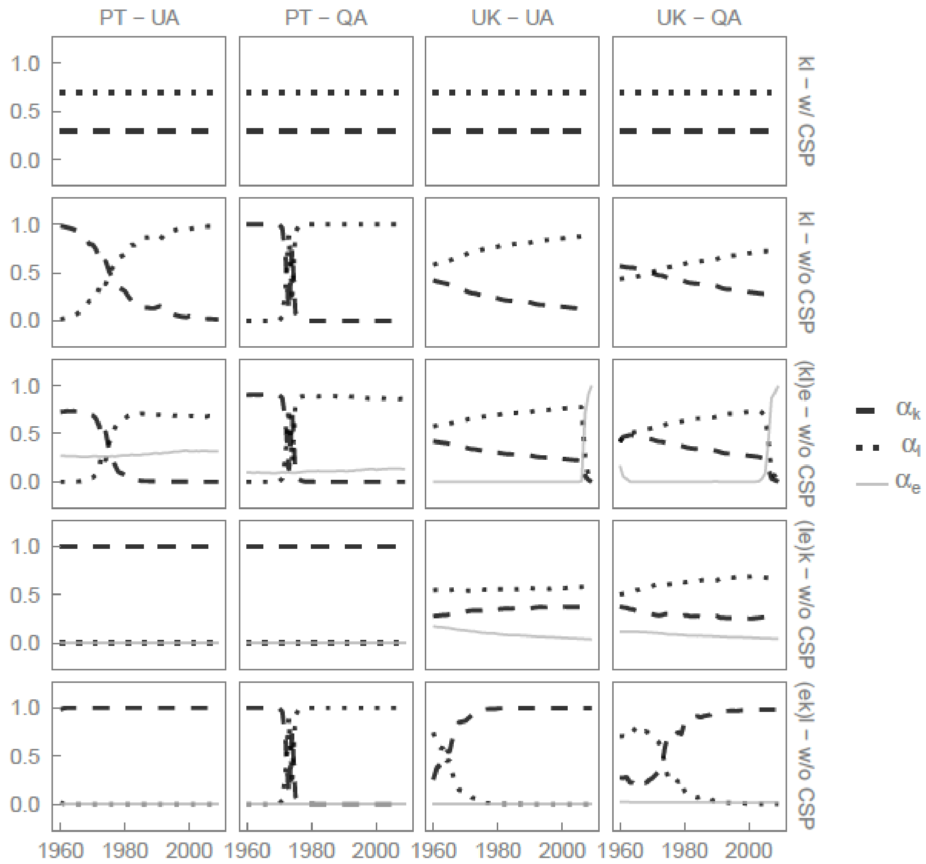

Figure 2 - Output elasticities of capital, labor, and energy for Portugal and the UK (1960-2009). "UA" indicates unadjusted inputs, and "QA" indicates quality-adjusted inputs.

For both countries, estimated output elasticities fail to reflect both the constant average cost shares assumed in the CSP-adhering model, and the historical cost shares observed for these countries.

For Portugal, the trend seems to be a transition from a capital-constrained economy, in the beginning of the period, to a labor-constrained economy, with energy (when present) having an impact in production that does not change considerably throughout the 50-year period.

As for the UK, results are mixed. This economy is less capital-constrained at the beginning of the period than Portugal, which is expected. Overall there seems to be an analogous transition to a more labor-constrained economy, as in Portugal, albeit at a slower rate. In the case of the model with a $(kl)e$ nesting structure, there is a suggestion that energy becomes the constraining factor by the end of the period, which coincides with the beginning of the economic crisis. Therefore, this can be argued as evidence that the recession was an energy recession.

Overall, the inclusion of energy only becomes significant for a handful of models analyzed here. Quality-adjusting all factors of production seems to impact the levels but not the long-term trends of estimated output elasticities. However, the nesting structure does affect significantly the evolution of estimated output elasticities. One should keep in mind that changing the nesting structure implies estimating a very different model, and so comparisons between nesting structures should be validated by other theoretical considerations, and purposes of the modeling approach.

3.1.3 *Parameter precision*

To demonstrate parameter precision, and in lieu of traditional techniques, we present results from a bootstrap resampling analysis of CES functions that reject the cost share principle, include energy, use quality-adjusted factors of production, and employ the $(kl)e$ nesting for both Portugal and the UK.

Figures (3-5) demonstrate several important points regarding the precision of parameter estimates. Figure (3) shows bootstrap resampling distributions for λ and θ. Parameter estimates are shown as crosshairs, and 1000 resample points are shown as dots with 95\% transparency. A striking feature of the bootstrap resampling distribution is its large vertical dispersion, indicating low precision in the estimated value of the Solow residual. Figure (4) shows bootstrap resampling distributions for δ and δ_1. This bootstrap resampling distribution shows comparatively very little dispersion for δ_1 relative to δ for both Portugal and the UK, indicating more precision for δ_1 than δ. Figure (5) shows bootstrap resampling distributions for α_k, α_l, and α_e. The α values are a function of time, and 100 lines are included on this graph.

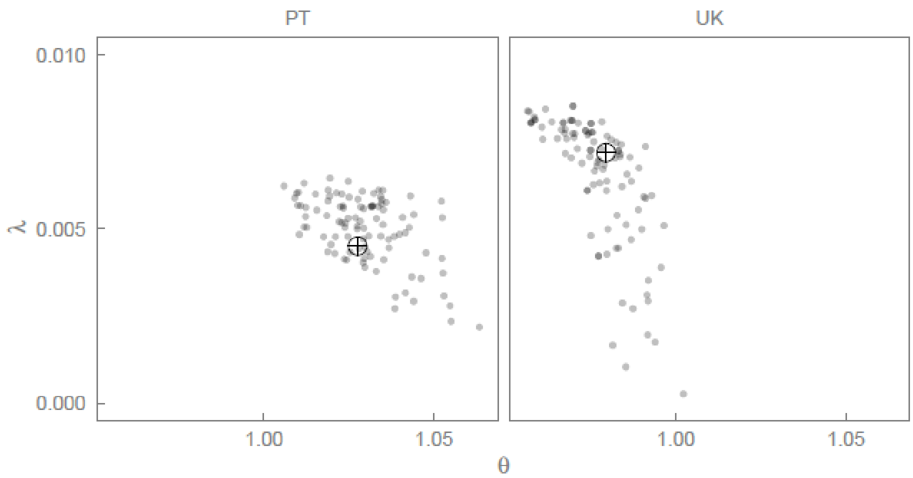

Figure 3 - Bootstrap resampling distribution for λ and θ for resampled CES functions that reject CSP, include energy, use quality-adjusted inputs, and employ (kl)e nesting.

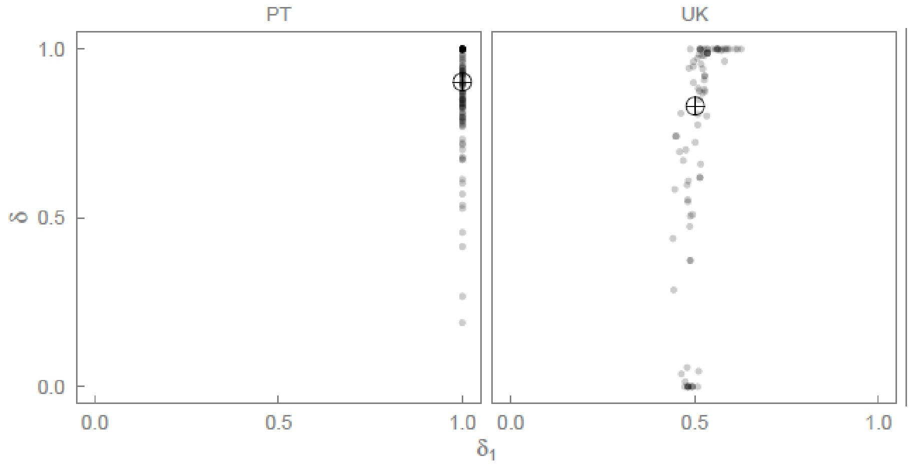

Figure 4 - Bootstrap resampling distribution for δ and δ_1 for resampled CES functions that reject CSP, include energy, use quality-adjusted inputs, and employ (kl)e nesting.

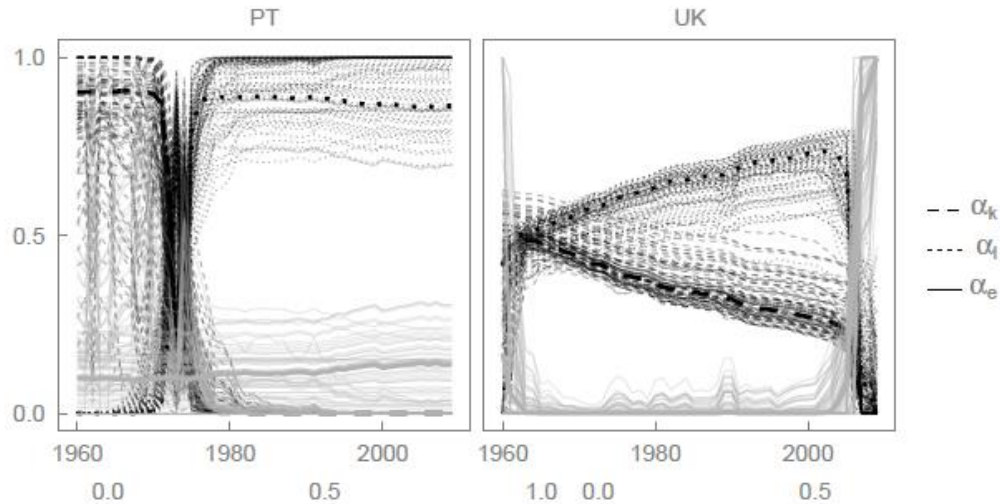

Figure 5 - Bootstrap resampling distribution for α_k, α_l and α_e for resampled CES functions that reject CSP, include energy, use quality-adjusted inputs, and employ (kl)e nesting.

Some parameters can be estimated with great precision, while others can be estimated with little or no precision. Second, precision information cannot be transferred from one economy to another. Each country must be analyzed independently. Third, the precision of output elasticities should be estimated *in addition to* the precision of parameters δ_1 and δ. Fourth, understanding of the output elasticities for the factors of production *must be* informed by the knowledge that many of the output elasticities are estimated with little precision. Fifth, the Portugal and UK examples in Figure (5) indicate that the timing of structural transitions *can* be estimated precisely, even if the output elasticities *cannot*.

Finally, it bears repeating that the resampling methodology utilized herein provides an *indication* of precision only. Further investigation and development of analytical methods to estimate parameter precision is warranted.

4 CONCLUSIONS

We conclude with three points: (a) inspiration from ecological economics provides better CES models; (b) precision is essential for interpreting point estimates of parameters in CES models; and (c) some CES models may say more about modeling choices than about the economy.

We find that modeling choices inspired by ecological economics (rejecting the CSP, including energy, and quality adjusting the factors of production) produce CES models with lower SSE in nearly all cases. Most of the SSE benefit is obtained by rejecting the cost share principle. Quality adjusting the factors of production provides little change to (and, in some cases, slightly increases) SSE. However, in all cases, quality adjusting the factors of production reduces the Solow residual. In many cases, adding energy and choosing the $(kl)e$ nesting structure provides a small benefit to reducing SSE, but results are inconsistent. Including energy after rejecting the CSP yields larger λ while slightly decreasing SSE.

Point estimates of parameters should not be interpreted without some understanding of their precision. In this study, we employed bootstrap resampling to provide an indication of parameter precision. There are several where cases differences in parameter estimates between two models constructed with different modeling choices are small relative to precision of the estimates either model provides. For example, the range of $+0.002$/year to -0.005/year for resampled λ values for the UK with $(kl)e$ nesting structure. Also, the differences among λ values for several modeling choices is much less than the range of resampled λ values, indicating that great care must be taken when interpreting estimated values of Solow residual.

Modeling choices have a significant effect on output elasticities. Some models for a given country exhibit structural transformations while others do not. For example, consider CES models that reject the CSP and include energy as an input. For Portugal with the $(kl)e$ nesting structure, a clear transition from capital-dominated marginal productivity to labor-dominated marginal productivity occurs near the time of the Carnation Revolution (1974), regardless of whether the factors of production are quality adjusted. However, the $(le)k$ nesting structure indicates that no such transition occurred, and the $(ek)l$ nesting structure indicates that the transition is a function of whether the factors of production are quality adjusted or not. It cannot be true that the Portuguese economy both did and did not experience a transition from capital-dominated to labor-dominated marginal productivity. Similar questions arise when evaluating the UK economy. The $(kl)e$ nesting structure indicates that a transition to energy-dominated marginal productivity occurred about 2006; the $(le)k$ nesting structure shows a steady increase of labor's marginal productivity; and the $(ek)l$ nesting structure indicates a transition from labor-dominated to capital-dominated marginal productivity. Again, it cannot be true that the UK economy experienced all of these transitions. Structural transitions are a robust result: all Portuguese and UK resample models exhibit the structural transitions near, but not precisely at, 1974 and 2006, respectively.

When faced with the question "Which nesting structure should be employed?" what is a modeler or a policy-maker to do? The uncomfortable reality is that modeling choices have a significant effect on all results, especially output elasticities. Some modeling choices (nesting structure and quality adjustment) may say more about the model than the economy.

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The energy-growth nexus: further evidence from disaggregate renewable energy sources

Kateryna Kochergina[1], Henrique Monteiro[2]

[1]*University of Warsaw/ISCTE-IUL (double degree program), Długa 44/50, Warsaw, Poland,* *kkaaa1111@iscte-iul.pt*
[2]*Instituto Universitário de Lisboa (ISCTE-IUL), BRU-IUL, Av das Forças Armadas,1649-026, Lisboa, Portugal,* *henrique.monteiro@iscte.pt*

ABSTRACT

This study explores the relationship between economic growth and disaggregate renewable energy sources (hydropower, biomass, wind, and solar energies) in twenty OECD countries over the period 1993-2012, a period during which the importance of renewable energy sources has grown substantially, mainly due to their role in mitigating greenhouse gas emissions. Applying recently developed panel time series techniques, we controls for unobserved heterogeneity and cross-section dependence between countries. The empirical findings suggest that there is no long-run relationship between economic growth and the different types of renewable energy. However, the results of short-run estimation show that different renewables have diverse impacts on economic growth. While biomass energy production contributes to economic growth, wind energy generation might have a negative impact on economic activity. The remaining two renewable energy categories (hydropower and solar energy) don't appear to affect economic growth in the short run. The evidence of no interrelationship between the analyzed renewable energy sources and economic activity might be explained by their relatively low share in total energy production.

Overall, the estimations results show that substantial renewable energy subsidizing doesn't harm economic activity and so suggest continuing governmental support policies towards renewable energy deployment.

KEYWORDS: Renewable energy, economic growth, panel time series, cross-sectional dependence

INTRODUCTION AND BRIEF LITERATURE OVERVIEW

With increasing concerns about global warming accompanied with fossil energy resources depletion more and more countries consider renewable energy sources as an essential component of their energy mix. During 2004-2014 overall growth of primary energy supply from renewables reached 30%, while in 2014 59% of net additions to global power capacity belonged to renewable energy sources (REN21, 2015)(REN21, 2015).

The significance of energy for the process of economic development is well known fact that has been proven in a number of empirical studies (Soytas & Sari, 2003; Apergis & Payne, 2009; Ozturk, 2010; Drege et al., 2010). Stern (2004) provides a detailed analysis of the key factors that cause and affect the link between energy use and economic activity insisting that energy is a significant production input. However, the literature related to the renewable energy and economic growth nexus is quite recent.

In a series of studies, Apergis and Payne (2010, 2012a, 2012b) looked into the causal relationship between disaggregated energy consumption and economic growth for different countries. In case of Central American states bidirectional causality was found between both renewable (in the long run) and nonrenewable energy (both in the short and the long run) consumption and growth (Apergis & Payne, 2012a). The results presented in their encompassing paper that covered data on 80 countries also suggested that both types of energy sources were important for economic growth (Apergis & Payne, 2012b).

The research presented by Tiwari (2011) analyzed Eurasian countries covering the period of 1965-2009. The main finding demonstrated that renewable energy consumption contributed positively to economic growth. Applying a panel cointegration test for fifteen EU countries Ucan et al. (2014) confirmed the findings of Tiwari (2011). Although an increase in renewable energy consumption resulted in real GDP growth, total non-renewable energy consumption had a negative impact on economic activity. However, disaggregated energy data demonstrated that the nature of the impact varied. While solid fuels (like coal) remained harmful for the economy, petroleum had a positive impact on real GDP.

Based on the results of the analysis of the causal relationship between GDP, CO2 emissions, and electricity generation from renewable energy sources in four countries (Denmark, Portugal, Spain, and US) Silva et al. (2012) argued that the increasing share of the electricity produced from the renewables might initially harm economic growth (except of USA).

Even though the conclusions on the nature of dynamics between renewable energy and economic growth are still contentious, researchers have agreed that tapping into renewable energy sources contributes to a country’s economy.

It should be pointed out that the majority of the existing studies focused on the causal relationship between energy consumption and economic growth using aggregate energy consumption data. However, the extent to which different countries depend on various energy sources is not the same(Yang, 2000). That is why focusing on purely aggregate data is not enough to identify the impact of a specific energy type on economy(Sari, Ewing, & Soytas, 2008). So far comparatively little attention has been placed on the different types of renewable energy and its impact on economic activity. To our knowledge there is only one study that is focused on causal relationship between economic growth and energy generated from different renewable energy sources. Analyzing a set of OECD member countries Ohler & Fetters (2014) find out that the way different renewables affect GDP varies from one energy type to the other. They find that while biomass and waste energy production appear to have a negative impact on economic growth, hydroelectricity and wind energy might stimulate it. However, the results obtained seem to be sensitive to the methodology applied in the study. Contrary to Ohler & Fetters (2014), our conclusions are based on the results from the analysis of the empirical model that includes both factors of production (capital and labor). At the same time we account for a size properties of the cointegration test (Pedroni, 1999).

This study contributes to existing literature providing more insights on the specific impact of each renewable energy type on the economy. Using new panel data methods we attempt to deal with issues that may cause misleading conclusions, but haven’t been taken into account in the previous studies (Chen et al. 2007, Menyah & Wolde-Rufael 2010, Lee & Chang 2007, Menegaki 2011). The rest of the paper is organized in the following way: Section 2 describes theoretical framework and the data. Section 3 provides initial data analysis, while Section 4 presents econometric techniques and the results on energy-growth relationship analysis. Finally, Section 5 concludes.

2. THEORETICAL FRAMEWORK AND DATA

Following several energy studies that consider a multivariate setting we apply a Cobb-Douglas production framework to examine the relationship between disaggregated renewable energy production and GDP for a set of OECD countries. Incorporating energy production from different renewable and conventional power sources we assume that the production function has the following functional form:

$$Y_{i,t} = A_i K_{i,t}^{\alpha} L_{i,t}^{\beta} N_{i,t}^{\gamma_1} \prod_{j=2}^{J} R_{i,j,t}^{\gamma_j} \qquad (1)$$

where $Y_{i,t}$ stands for country i's aggregate output in period t, $K_{i,t}$ is a country's stock of capital, $L_{i,t}$ is labor force, $N_{i,t}$ denotes the input of conventional energy, while $R_{i,j,t}$ stands for the input of each of the $J-1$ renewable energy sources considered, A_i stands for i's country technological progress.

To reduce heteroskedasticity in residuals and avoid the possible problem of not having a normal distribution all variables are transformed into the logarithmic form(Acemoglu, 2008):

$$lnY_{i,t} = a_i + \alpha lnK_{i,t} + \beta lnL_{i,t} + \gamma_1 lnN_{i,t} + \sum_{j=2}^{J} \gamma_j lnR_{i,t,j} \qquad (2)$$

where $a_i = \ln(A_i)$. Coefficients α and β measure the elasticity of output with respect to capital and labor, while $\gamma_1$and γ_j define, respectively, the elasticity of total output with respect to conventional (non-renewable) energy sources and each of the renewable ones. The model presented includes a time dimension denoted by t $(t = 1,2,\dots,T)$, and cross sectional dimension denoted by i $(i = 1,2,\dots,I)$.

Our study includes twenty OECD member states[1] over the 1993-2012 period. The choice of countries was mainly the relative importance of renewable energy sources in the countries' energy mix. In many countries the usage of renewable energy sources was negligible or even zero causing a substantial amount of zero data points, which would lead to the problem of excess zeroes. Additionally, for robust estimation with panel time series data the variables should have temporal variation. Moreover, the methodological procedure, which has been widely used for the analysis of the energy-growth nexus and is the most appropriate for our study, is based on the averaging (or weighted averaging) of the estimated coefficients. Such a procedure is sensitive to the presence of outliers (Ciarlone, 2011).

In this study GDP measured in constant 2010 million US dollars. Due to its use in natural logarithmic form, the first differences can be considered as an approximation for the variables' growth rates. Capital stock is approximated by gross fixed capital formation measured in constant 2010 million US dollars. For labor force we use the economically active population expressed in thousands of people. All above mentioned data are obtained from OECD statistics.

Conventional electricity generation was calculated as a sum of electricity generated from fossil fuels and nuclear energy sources. Disaggregated renewable electricity generation is presented by power production from biowaste, hydroelectric, solar, and wind energy sources. The data for all energy variables is measured in million kilowatt hours and obtained from the US Energy Information Administration.

3. PRELIMINARY DATA ANALYSIS

3.1. Cross sectional dependence

The equation (2) shows that all variables are transformed into their natural logarithmic form. Consequently, the first differences can be considered as an approximation for the variables' growth rates.

Due to the relatively short time spam of our sample, we use panel time series data techniques The panel data approach provides an improvement over individual country time-series estimation by including information on the cross-sectional dimension and improving efficiency of the tests by eliminating the problem of low degrees of freedom. .

[1] Austria, Australia, Belgium, Canada, Denmark, Finland, France, Germany, Italy, Netherlands, Norway, Spain, Sweden, Switzerland, Portugal, United Kingdom, United States of America, Japan, South Korea, and Mexico

One of the major concerns in panel data studies is related to the possibility that individual groups are interdependent. In case of cross sectional dependence (CSD), residual based tests might lead to incorrect statistical inference. In particular, Phillips & Sul (2003) show that ignorance of CSD significantly diminishes the efficiency gains from data pooling. To test CSD we use the test statistics proposed by Pesaran (2004b)[2]. Table 1 reports the average correlation coefficients and CD_p test statistics, which test the null of cross-sectional independence. These results show that all of the variables considered are dependent across countries. To avoid misleading inference[3], the presence of cross-section correlation will be taken into account in further steps of this study.

Table 1. Cross-section dependence test

Variable	CD- test	p-value	Correlation
Ln(GDP)	59.90***	0.000	0.972
Ln(capital)	33.06***	0.000	0.536
Ln(labor)	48.69***	0.000	0.790
Ln(conventional)	34.25***	0.000	0.596
Ln(hydro)	4.60***	0.000	0.075
Ln(biowaste)	48.99***	0.000	0.795
Ln(wind)	57.14***	0.000	0.927
Ln(solar)	53.99***	0.000	0.876

3.2. Unit root

In the next step of our analysis we check the order of integration of variables. We apply two unit root tests, IPS (Im et al. (2003)) and CIPS (Pesaran (2007)), with a null hypothesis of non-stationarity (presence of unit root) for both of them. These tests are based on the augmented Dickey–Fuller regressions. The main feature of these panel unit root tests is the high level of parameter heterogeneity[4] allowed by the test procedures. However, the IPS test relies on the assumption of identically and independently distributed data (cross sectional independence). According to Banerjee et al. (2005) the presence of cross sectional dependence leads to size distortions and poor performance of panel unit root tests. From the results of the above presented CSD test we see that the assumption of IPS might be too restrictive for our sample. That is why Pesaran (2007) test will assure the conclusions on the nature of variables behavior. By augmenting Dickey–Fuller regressions with the cross-section averages of lagged levels and first-differences of the individual series it accounts for data interdependence.

Table 2. Unit root testssummarizes the results of panel unit root tests: IPS[5] in the first column and Pesaran (2007) test[6] in the second one. For all of the variables the tests includes a constant and a trend. The tests' output indicate that the level values of gdp, capital, labor, biomass, wind, and solar energy sources are non-stationary, while their first differences are stationary at the 1% level of significance. At the same time the null of non-stationarity for the level value of hydro power energy can be rejected at the 1% level of freedom. However, the outputs for conventional energy are inconsistent. While IPS test defines conventional energy to be first-difference stationary, the significant negative value of CIPS statistics for this variable allows us to reject the null of unit root leading to conclusion that conventional energy exhibits stationary behavior. The difference in the unit root test outputs for the conventional energy demonstrates the importance of controlling for CSD. Given the presence of cross country dependence, we believe that Pesaran (2007) unit roots test gives more reliable inference than those methodologies that do not account for CSD.

[2] This test is performed with xtcd Stata command(Eberhardt, 2011).
[3]Particularly, when common shocks (the source of CSD) are correlated with the regressors (Andrews, 2005) .
[4]In particular, residual serial correlation, heterogeneity of the dynamics and error variances across groups may be considered by the tests applied in this study.
[5] The test statistics computation was done using Stata command *xtunitroot* with an option *ips* (StataCorp, 2013).
[6] The test is implemented with Stata command *xtcd* (Eberhardt, 2011).

Table 2. Unit root tests

Variable	IPS		CIPS	
	t-statistics	p-value	t-statistics	Critical t-statistics
GDP ΔGDP	5.8745 - 7.9434	1.0000 0.0000	- 1.980 - 3.423	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Capital Δ Capital	1.3420 - 8.1898	0.9102 0.0000	- 1.946 - 3.894	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Labor Δ Labor	- 0.7186 - 3.6763	0.2362 0.0000	- 2.512 - 3.546	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Conventional Δ Conventional	0.5104 - 13.1771	0.6951 0.0000	-2.946	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Hydropower	- 7.2658	0.0000	- 3.994	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Biomass Δ Biomass	-0.1595 -9.9638	0.4366 0.0000	-1.894 -4.035	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Wind Δ Wind	-1.3483 - 10. 2479	0.0888 0.0000	- 2.119 - 3.663	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630
Solar Δ Solar	4.9209 - 15.2109	1.0000 0.0000	- 1.906 - 3.402	Cv1: - 2.920 Cv5: - 2.70 Cv10: - 2.630

The conclusion that hydropower is stationary is in line with the results presented by Lean & Smyth (2014), who analyzes the behavior of hydropower generation in 55 countries[7].

The stationary nature of non-renewable electricity generation can be related to the fact that, during the last decade, developed countries have been focused on decreasing the energy-intensity level. Thus, the amount of electricity generated from conventional energy sources has been stable relatively to economic growth.

[7] In this study, the authors apply LM unit root test for 55 countries over the period of 1965 -2011. The rejection of unit root was supported for three quarters of their sample among which majority of OECD members.

4. ENERGY-GROWTH RELATIONSHIP ANALYSIS

4.1. Cointegration test

According to Pedroni (1999), cointegration refers to the idea that for a set of nonstationary variables, some linear combination of these variables exhibits stationary nature. GDP and hydropower electricity generation as well as GDP and conventional electricity production can't have a long-run relationship as they have different orders of integration. Therefore, conventional and hydro energy sources are not included in the testing for the presence of cointegration relationship.

To verify whether analyzed variables exhibit long-run relationship we use several residual based tests proposed by Pedroni (1999). The first step is to obtain the residuals from the following regression for each of the panel member:

$$y_{i,t} = \alpha_i + \delta_i t + \sum_{m=1}^{M} \beta_{mi} x_{mi,t} + \epsilon_{i,t} \quad (3)$$

where $t = 1, \dots, T$; $i = 1, \dots, N$; $m = 1, \dots, M$; $x_{i,t}$ is a vector of individual-specific and common regressors. The individual intercepts, α_i, and the slope coefficients, β_i, are allowed to vary across panel members. M is the number of regressors; $\epsilon_{i,t}$ are residuals indicating deviations from the long run equilibrium. The second step is to pool residuals computed on the first stage and test the null that $\epsilon_{i,t}$ is I(1), i.e. no cointegration relationship order:

$$\epsilon_{i,t} = \rho_i \epsilon_{i,t-1} + u_{i,t} \quad (4)$$

The validity of the null can is tested by seven different statistics[8] (table 3). Four of them, so called within dimension (panel) test statistics, consider the homogeneous case, when all slope coefficients (ρ_i) are assumed to be the same across panels. The remaining three test statistics (between dimension or group statistics) represent the heterogeneous case, when cointegrating vectors are allowed to vary across groups. In fact, the true slope coefficients are likely to vary across individuals, and so group statistics may provide more reliable results.

Table 3. Pedroni (1999) cointegration test

	Biomass		**Wind**		**Solar**		**Biomass, wind, and solar**	
Test	**t-statistics**	**p-value**	**t-statistics**	**p-value**	**t-statistics**	**p-value**	**t-statistics**	**p-value**
Panel v-Statistic	0.6852	0.2466	0.0681	0.4728	1.2496	0.1057	-1.1119	0.8689
Panel rho-Statistic	3.0839	0.9990	3.3921	0.9997	3.3821	0.9996	4.6117	1.0000
Panel PP-Statistic	-1.1104	0.1334	0.6496	0.7420	0.7167	0.7632	-1.3990	0.0809
Panel ADF-Statistic	-1.8264	0.0339	-0.0734	0.4707	-0.4456	0.3278	-1.6019	0.0546
Group rho-Statistic	4.6998	1.0000	4.2758	1.0000	4.4138	1.0000	6.1583	1.0000
Group PP-Statistic	-0.9234	0.1779	-2.0909	0.0183	-0.8136	0.2079	-5.3687	0.0000
Group ADF-Statistic	-0.8502	0.1976	-1.1631	0.1224	-1.7908	0.0367	-2.1821	0.0146

[8] Test statistics are calculated via the econometric software Eviews 8.0

The p-values obtained from the models that analyze relationship between individual renewable energy sources and GDP show that there is no strong reason to reject the null of no long–run relationship. According to the results only one of the test statistics for each of the considered GDP-energy source models allows us to reject the null - group-PP (for GDP-wind), group-ADF (for GDP-solar), and panel-ADF (for GDP-biomass).

The results from the model that includes three renewable energy types simultaneously don't provide the clear evidence about the nature of the relationship between them. The p-values of PP- and ADF statistics allow us to reject the null of no cointegration, while remaining test statistics suggest that we have no reason to reject the null.

In light of the results inconsistency we should identify which of the test statistics has a higher power. In a number of experiments (Pedroni, 2004) shows that in small size samples group-rho statistics dominates other test statistics. According to Pedroni (2004) small sample studies can be relatively confident about group-rho statistics results. On the other hand one of his experiments was performed for the case of $N = 20$ (number of panels considered in our study) and showed that panel-t tests (PP and ADF) had the highest power. Similar conclusion were reported by Örsal (2007).

Summing up we can state that, since the time span and the number of countries in our sample is relatively short, the possibility of null hypothesis rejection is best determined by group-rho statistic followed by panel-t statistic. The p-values of two of these statistics show that we have no reason to reject the null of no cointegration at the 5% level of significance (with rho-statistics suggesting strong non-rejection of the null).

It is important to note that the cointegration technique by Pedroni (1999), widely used in the energy-growth literature (Apergis & Payne, 2009; Ohler & Fetters, 2014; Ucan et al., 2014; Sadorsky, 2009), relies on the assumption of cross-sectional independence. However, we have shown that CSD is present in our data.. That is why, in addition to Pedroni (1999) cointegration test we apply the technique proposed by Westerlund (2007) that is robust to CSD. This procedure includes four test statistics, two panel and two group mean statistics. Each of the tests is designed to test the null of no cointegration by verifying whether the error correction term in a conditional error correction model is statistically insignificant. Therefore, the tests consider the following data generation process:

$$\Delta y_{i,t} = \delta_i d_t + \alpha_i\left(y_{i,t-1} - \beta_i x_{i,t-1}\right) + \sum_{j=1}^{p_i} \alpha_{i,j}\Delta y_{i,t-1} + \sum_{j=-q_i}^{p_i} \gamma_{i,j}\Delta x_{i,t-j} + e_{i,t} \tag{5}$$

where d_t represents the deterministic component. Thus, the null of no cointegration is formulated as $H_0\colon \alpha_i = 0$ for all i. The difference between panel and group mean test statistics is that for the alternative hypothesis formulation the former ones assume α_i to be the same across panels, while the later statistics allow this parameter to vary. Following the author we use 500 bootstrap replications to control for CSD.

Table 4 provides the results[9] for the models that consider different renewable energy sources individually (biomass, wind and solar energies), and for the model that includes them simultaneously. The robust probability values for all models specifications report that there is no reason to reject the null of no cointegration between variables. Therefore, we conclude that there is no long run simultaneous relationship between GDP and renewable energy sources considered in all countries included in the sample

Table 4. Westerlund (2007) cointegration test

Energy variable	G_t - statistics	G_a-statistics	P_t -statistics	P_a -statistics
Biomass	0.946	0.962	0.922	0.834
Wind	0.984	0.316	0.942	0.858
Solar	0.420	0.516	0.530	0.320
Biomass, wind, solar	0.194	0.440	0.678	0.254

However, it doesn't necessarily mean that none of the analyzed countries exhibits the cointegration relationship between these variables. It might be the case that the nature of the linkage between GDP and renewables in the long run is country specific.

[9] The test is performed with Stata command *xtwest* (Persyn, 2010).

4.2. Analysis of short-run dynamics analysis

To examine whether renewable energy production affects economic activity in the short-run we apply the widely used ARDL approach proposed by Shin et al. (1999). The procedures consider the following ARDL (p_i, q_i) model:

$$\Delta y_{i,t} = \varphi_i\left(y_{i,t-1} - \theta_i x_{i,t}\right) + \sum_{j=1}^{p-1} \gamma_{i,j} \Delta y_{i,t-1} + \sum_{j=0}^{q-1} \delta_{i,t} \Delta x_{i,t-j} + \mu_i + \varepsilon_{i,t} \tag{6}$$

where $x_{i,t}$ is a set of explanatory variables for each group, μ_i represents the country-specific intercepts, φ is an error-correcting term, $\gamma_{i,j}$ and $\delta_{i,j}$ reflect short term country-specific coefficients, ε_i is the error term in each cross section. The equation (6) is estimated by maximum likelihood. Such model specification allows the intercepts, short-run coefficients, and error variances to vary across groups, but constraints the long run coefficients to be the same.

Given that our sample exhibits CSD we apply the technique developed by Pesaran (2004a). Due to the limited number of observations we aren't able to estimate model specifications that consider more than three explanatory variables[10]. Moreover, data limitation restricts the number of factors' means to be included in the model to three. However, we suppose that for the analysis of economic growth removing a variable of capital or labor is theoretically wrong. Therefore, using the production function framework (see equation 1 and 2) we augment the model with the means of GDP, capital, and the energy variable, without controlling for interdependence of labor force between panels. The analyzed models are conducted in a way to investigate the impact of renewable energy sources on GDP separately. Estimations of the equations, which include the first difference of GDP as a dependent variable and lagged differences of the explanatory factors, have been carried out using the Stata command *xtpmg* (Blackburne & Frank, 2007b)[11]. More detailed description of the model construction can be found in Kochergina (2015).

The outputs of the short-run dynamic estimations are presented in
Table 5[12]. Due to the fact that cointegration tests results provide an evidence that in the long run analyzed variables are not interrelated, the long run estimation part is no longer in our main focus. In particular, EC terms appear to be insignificant in the models for hydropower and solar energy that confirms our previous conclusion of no cointegration relationship.

The short-run estimates show that two renewable energy sources out of four considered have an impact on economic growth. While biomass positively affects GDP, the coefficient for the wind energy generation shows that it might have a negative impact on the economic activity in the short run. The negative impact of wind energy on GDP might be related to the cost of the wind equipment import. In 2012, for example, the amount of imported wind power equipment increased the US trade imbalance on USD 2.6 billion (NREL, 2013). Therefore, the wind power installation spending might be a reason for this energy source affects GDP negatively, but only in the short run.

Table 5. Panel ARDL estimation

Model specification	**Capital**		**Labor**		**RE variable**		**EC term**
	Long-run	**Short - run**	**Long-run**	**Short – run**	**Long-run**	**Short – run**	
Hydropower	0.5885 (0.000)	0.1381 (0.000)	0.0525 (0.572)	0.2328 (0.121)	0.0512 (0.001)	0.0025 (0.563)	- 0. 075 (0.097)
Biomass	0.4048 (0.000)	0.133 (0.000)	-0.1472 (0.047)	0.2066 (0.283)	-0.163 (0.018)	0.0122 (0.023)	-0.1639 (0.008)

[10] For the size of our sample the ARDL model can be estimated with seven regressors maximum. However, to account for CSD we follow(Pesaran, 2004b)) and augment estimated models with the means of each of the variables (independent and dependent), which consequently limited the number of regressors we can include in the model.

[11] Detailed description of the command can be found in (Blackburne & Frank, 2007a).

[12] We only present the averages estimates and not the country specific coefficients.

Model specification	Capital		Labor		RE variable		EC term
	Long-run	Short -run	Long-run	Short –run	Long-run	Short –run	
Wind	0.2729 (0.000)	0.0973 (0.025)	0.5478 (0.000)	0.1906 (0.433)	0.0166 (0.000)	-0.0066 (0.007)	-0.2159 (0.021)
Solar	0.0704 (0.291)	0.1424 (0.000)	0.9800 (0.000)	0.3201 (0.126)	0.1421 (0.000)	-0.0021 (0.792)	-0.758 (0.190)

The p-value for solar energy generation shows that there's no statistically significant relationship with economic growth. This conclusion is in line with the findings presented by Ohler & Fetters (2014)[13]. This fact might be explained by the share of solar energy sources in total electricity generation, which remains relatively low (BP, 2015). Similar to Silva (2012), whose structural VAR analysis shows that changes in the hydropower generation don't affect GDP, our results reveal that hydropower has no short–run impact on economic growth either. One possible explanation is the "decreasing dominance" of hydropower sources partially caused by the rapid growth of other renewables (EmployRES, 2009). Moreover, the majority of countries considered in our study don't exhibit significant hydropower deployment in recent years (REN21, 2015). Chien & Hu (2008) conclude that renewables affect GDP by the means of increasing capital formation level. Therefore, we might suspect that the actual impact of renewable energy sources depends not on the amount of energy produced but the level of new capacity installed, which would explain the nature of short–run relationship between hydropower and economic growth.

5. CONCLUSION

This study examines the relationship between economic growth and different types of renewables (hydropower, biomass, wind, and solar energies) for twenty OECD member states over the 1993-2012 period. For this purpose, we implement new panel time series techniques, mainly panel unit root tests, panel cointegration tests, and panel ARDL approach for short–run estimation.

The results of the cointegration tests show that there is no long-run relationship between individual renewable energy sources and economic activity. Moreover, according to the unit root test outputs, hydropower generation and GDP have different order of intergration that provides evidence on no long-run relationship between these variables.

The estimations of the short–run dynamics reveal that biomass power generation contributes to economic growth, while wind energy affects economic growth negatively. However, this impact is very low and can be related to a high level of initial capital costs, which, nevertheless, are most likely to be outweighed in the long–run.

Even though our results don't find a support for a long–run relationship between economic growth and renewable energy we believe that these energy sources are important tools for sustainable development. Despite the significant growth of renewable energy usage, they are mostly used for electricity generation, while the highest share of total final energy consumption (TFEC) belongs to oil. Moreover, our study examines disaggregate renewable energy sources, whose share in TFEC is even lower and so their impact on economic activity might be small.

At the same time our conclusions show that recent renewable energy penetration accompanied with significant government support doesn't create a burden for overall economic activity. Consequently, governments should keep taking further steps in supporting renewable energy industry. There might be a need for new more cost-efficient renewables assistance programs. But further development of this industry still relies on these schemes, which long-run benefits will outweigh.

It should be pointed out that due to data limitation we couldn't analyze the impact of different renewables and traditional energy sources on GDP simultaneously. Therefore, further research might consider a longer time span and estimate the influence of disaggregate categories of conventional and renewable energy sources on economic activity together, checking for bidirectional causality. At the same time because of the limited number of observations we don't control for the presence of interdependence between labor force across countries. Future investigation might

[13] According to the results of panel error correction model that account for CSD

create a data base that enables the estimation of the model augmented with the means for all regressors. Given the importance of renewable energy in meeting emission reduction targets we also suggest examining the impact of individual renewable energy sources on the level of CO2 emissions.

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Comparison of environmental impacts of Renewable and non-Renewable energy

Bolea M[1], Bolea I[2], Serra L[3]

University of Zaragoza. María de Luna 3, Zaragoza, Spain
[1] *mbolea@unizar.es*
[2] *irene.bolea@gmail.com*
[3] *serra@unizar.es*

ABSTRACT

The impact of renewable energy generation compared to fossil fuel generation is quantified in this paper. The main objective is the comparison of the environmental impacts associated to electricity generation from two different sources: a conventional coal power plant, which includes CO_2 capture based on post combustion amine-based technology, and a wind energy generation, with a comparable power output as the power plant.

The Life Cycle Assessment (LCA) is applied for both technologies, through the software *SimaPro 8.0*. This tool uses standardized procedures, such as the ISO 14044, 2006. The methodology applied is *IMPACT 2002+*, which quantifies the following indicators: i) human health damage, ii) ecosystem quality, iii) depletion of resources, and iv) climate change contribution.

The LCA results show great reduction on climate change contribution when using CO_2 capture in coal power plants. In addition, it also indicates the resources depletion by fossil fuel utilization for energy generation. On the other hand, the major impact of the wind generation plant is the use of materials for manufacturing.

KEYWORDS: Life Cycle Assessment (LCA), environmental impacts, CO_2 capture, coal power plant, wind energy

1 INTRODUCCIÓN

Fossil Fuel power and heat generation contributed around 25% to global CO_2 emissions in 2010 (IPCC, 2014). Estimates according to the current tendencies of global economies, indicate that this situation will get worse, particularly due to the increase energy demand in great populated developing countries, e.g China and India.

Technology is playing a key role to limit CO_2 emissions. In this sense, the Intergovernmental Panel on Climate Change proposes the following options (IPCC, 2005):

1)To reduce primary energy consumption, for example, by increasing energy efficiency
2)To use alternative fuels, like natural gas instead of coal
3)To increase renewable energy generation
4)To improve biologic CO_2 absorption, for example by reforesting
5)To capture and storage CO_2 emissions

CO_2 capture and storage (CCS) technologies aim to avoid CO_2 emissions generated in the combustion, in industry and power plants. These technologies are traditionally classified in three groups: i) pre-combustion technologies, in which the fuel is converted so that the CO_2 emissions are concentrated at outlet; ii) oxy-fuel combustion, which uses oxygen (with no nitrogen); iii) post- combustion technologies, in which the flue gas is treated chemically or physically. In this last group, amine-based solvents are the most mature and feasible at great scale.

To evaluate CO_2 capture technology feasibility, main parameters should address the costs, reduction of emissions capacity and the primary energy demanded.

Much effort has been devoted to renewable energy generation during last decades. Wind energy has already reached a maturity level enough to be competitive versus conventional generation. However, this technology presents also few drawbacks that must be taken into account.

In this paper, are compared both technologies, amine based carbon capture and wind energy generation, with the aim of being able to answer the following questions:

a) How much real impact has a conventional coal power plant when CO_2 capture plant is integrated, considering the required chemicals addition and the extra-fuel needed to regenerate solvents?

b) Keeping in mind that there is no technology with zero impact, how much more environmental advantageous is a well-established renewable energy plant, like wind energy, to produce equivalent power output than a conventional coal power plant?

c) How much more impact has a coal power plant with CO_2 capture versus a wind energy power plant?

To address these issues, the impacts of each technology should be quantified. Life Cycle Assesment (LCA) is an appropriate tool to do it. Life cycle concept make reference to consider all the phases of the product life: resources extraction, manufacturing, distribution, use and final disposition. LCA results provide the environmental impacts of a product, process or activity, taking into account all those aspects.

In this work, LCA is carried out to the involved systems:

i) A conventional coal power plant, with an average size of 355 MW

ii) A CO_2 capture plant able to avoid 90% of the emissions generated in the coal power plant

iii) The integration of both, conventional coal power plant with CO_2 capture, including the increase of fuel consumption due to energy requirements of chemical absorption process

iv) A wind energy field producing the equivalent power output than the reference coal plant.

2 METHODOLOGY: LIFE CYCLE ASSESMENT (LCA)

During last 15 years the use of LCA has been rapidly grown. In parallel, the international standardization of the LCA has been developed through ISO14044 (2006). The procedure is then to be carried out in four steps:

1) Objective and scope definition
2) LCA inventory
3) Impacts analysis
4) Results interpretation

2.1 Objective and scope definition

The size of the power plants in this study will be 355 MW. Coal power plant is using lignite as fuel, with a heating value of 19.75 MJ/kg. The plant life is 25 years, operating 7800 hours per year. Efficiency reaches 40%. Out of the scope of this study we leave the electrical connection to the network, the transformation substation and infrastructure.
CO_2 capture plant uses monoethanolamine (MEA) as chemical solvent capturing 100% of CO_2 generated in the plant. Out of the scope are the CO_2 compression, transport and storage.
Wind energy generation uses as reference the Gamesa turbine, model G8X, with 2MW capacity each (Martínez et al. 2009). It operates 2000 hours average per year. LCA includes the construction of main components of the turbine, the transport to the wind field, assembly, installation, dismounting and wastes treatment. Out of the scope will be the electricity distribution, the transformation substation and the connection to the national network.

2.2 Inventory Analysis

This phase involves gathering the data for all entries (materials and energy), and for all outputs (emissions to air, to water or to soil), according to the limits of the system considered in the previous phase.
The inventory data of a lignite power plant, shown in Table 1, were gathered by Spath et al. (1999),.

Table 1. - Inventory of main materials in a coal power plant

Material	Kg/MW (of plant capacity)
Concrete	158.758
Steel	50.771
Aluminum	419
Iron	619

For the CO_2 capture plant, data presented by Fayedi et al. (2013) have been scale up for the current reference size and characteristics as shown in Table 2.

Table 2. - Inventory of the CO_2 capture plant main components

Equipment	Material	Quantity	Unity
Absorber	Stainless Steel	12877	Kg
Regenerator	Stainless Steel	10112	Kg
Packing material	Mellapak (250Y)	146307	Kg
MEA storage tank	High density polyethylene HDLPE	788.5	Kg
NaOH storage tank	High density polyethylene HDLPE	262.8	Kg
Piping	Stainless Steel	82000	Kg

As seen in Tables 1 and 2, main material for construction in both plants is steel and concrete. To evaluate the system, considerate has to be considered not only the construction phase, but also the maintenance and operation requirements during the plant life (Table 3)

Table 3. - Inventory of main needs of a power plant with CO_2 capture

Material	Quantity	Unity
Coal (lignite)	448.17	Kg/MWh
Limestone	90.70	Kg/MWh
Activated Carbon	0.075	Kg/ tCO2
NaOH	0.13	Kg/ tCO2
MEA (initial)	1.5	Kg/ tCO2
MEA (flow rate)	7090.3	kmol/h

Based on the work by Martínez et al. (2009) a wind energy plant inventory includes main components such as the foundations, tower, rotor and nacelle, Table 4.

Table 4.-Wind turbine inventory

Components		Material	Weight (Tm)
Rotor	3 blades	Resin Glass Fiber	11.7 7.8
	Blades core	Cast iron	14
	Conical Nose	Resin Glass Fiber	0.19 0.12
Base	Foundations	Concrete Cast Iron	700 25
Tower	3 sections	Stainless steel	143 15
Nacelle	Structure Main shaft	Cast Iron Stainless steel	10.5 6.1
	Transformer	Stainless steel Cupper Silica	3.3 1.5 0.15
	Generator	Stainless steel Cupper Silica	4.29 2 0.2
	Gear Box	Cast Iron Stainless steel	8 8
	Casing	Resin Glass Fiber	0.8 1.2

2.3 LCA Impacts analysis

This stage aims at translating the information on the use of resources and emissions from the previous phase, by means of different software:

a) SimaPro 8.02 (LCA Software 2014. Pré Consultants, 2014, Netherlands) is the one used in this work. This allows analyzing and comparing the environmental issues from a systematic and consistent way. It has powerful database, like Ecoinvent v3.1 (2014), which is one of the largest data base internationally
b) Impact Assessment of Chemical Toxics, IMPACT 2002+ (Humbert et al, 2014), is the methodology used in this work. It determines for each of the gathered inventory data, their contribution to every of the 14 impact middle point categories. These are grouped in four final point categories, damage categories (Jolliet et al., 2003): Human Health, Environment Quality, Climate Change and Resources Depletion.

3 RESULTS AND DISCUSSION

3.1 Environmental impacts comparison between the coal power plant with CO_2 capture and the wind energy plant

For comparing the impacts from both energy generation plants, the following have been considered:
- The lifetime of the coal power plant with CO_2 capture is 25 years, working 7800 hours per year and for the wind energy farm is 20 years, operating 2000 yearly hours.
- Same power output is produced in both cases. For a wind farm to produce the same electrical energy than a 355 MW coal power plant, the number of turbines required is 693, with a land used estimated of 15800 Ha.

Results from the LCA carried out for both technologies is shown in Table 5:

Table 5. - LCA results comparison between the impact of energy production by a conventional thermal power plant and a wind energy farm

Damage category	**Wind Farm**	**CPP+CC**
	Pt/GWh	**Pt/GWh**
Human Health	1.97	1.91
Ecosystem Quality	0.247	0.192
Climate Change	1.08	2.08
Resources	1.01	37.1
TOTAL	**4.31**	**41.3**

CPP: Coal Power Plant. CC: CO_2 Capture

From the table, impacts to the damage categories of Resources and Climate Change are greater for the CPP+CC than for the wind energy. The impact to the resources is up to 10 times higher. This difference is due to the fossil fuel consumption, which is non-renewable source.

Major impact to the human health is shown by the wind farm, due to the resins and glass fibers used for their manufacturing, particularly for the blades. These substances are considered with high toxicity by the Impact Assessment of Chemical Toxics, integrated in the data base Ecoinvent 3.1.

3.2 Environmental impacts comparison between the power plant with and without CO_2 capture

Table 6 shows LCA results on the environmental impacts of a Coal Power Plant with and without CO_2 capture. The difference is significant. Looking at the climate change impact, the abatement by capturing CO_2 is shown by reducing the points down to 1.2%. Damage to human health is also reduced down to 57 times smaller.

Table 6. - LCA comparison results for CPP with and without CC

Damage Category	CPP + CC	CPP
	Pt/GWh	Pt/GWh
Human Health	1.91	109.00
Ecosystem Quality	0.19	15.60
Climate Change	2.08	157.00
Resources	37.10	118.00
TOTAL	**41.3**	**400**

CPP: Coal Power Plant. CC: CO_2 Capture

4 CONCLUSIONS

The Life Cycle Assesment has allowed to obtain the four damage categories (Human Health, Ecosystem Quality, Climate Change, Resources), in order to quantify the environmental impacts of two great sources for energy generation: a coal power plant with CO_2 capture and a wind energy farm. The aim was to evaluate how environmentally advantageous was to include CO_2 capture into fossil fuel power plants and also, how this advantage was compared to renewable energy generation.

The following conclusions are drawn from this assessment:

1) The Coal Power Plant presented similar or greater values for the four damage categories, when compared with wind energy generation. Globally, the impact was one order of magnitude higher for the coal power plant with CO_2 capture and two orders of magnitude higher for the conventional coal power plant. It is remarkable the damage to the natural resources, due to the fossil fuel consumption. However, the damage to the human health presented high values for the wind turbines, due to the manufacturing materials used, considered of great toxicity.

2) When comparing LCA results of a coal power plant with and without CO_2 capture, the benefits of this CCS technology are remarkable, drastically reducing the impact to Human Health and Climate Change, reducing the total CPP impact down to 10% with respect to a conventional coal power plant.

This evaluation allowed to answer the questions raised at the beginning of this paper as well as to quantify the impacts of both generation technologies. The methodology IMPACT 2002+ has been used by first time to calculate the environmental impacts of a Coal Power Plant with CO_2 Capture and the Wind Energy Farm. Thus, the LCA procedure has been confirmed as a very useful tool to configure the appropriate energy mix within the context of CO_2 emissions reduction, and with the same tendency of energy consumption as predicted.

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Could households' small actions make a difference in reducing emissions? A CGE analysis for Spain

Cristina Sarasa[1], Rosa Duarte[2], Julio Sánchez-Chóliz[3]

[1] Department of Economic Analysis, Faculty of Economics and Business Studies, University of Zaragoza, Gran Vía 2, 50005 Zaragoza Spain. Tel: +34 876554728; Fax: +34 976761996. Email: csarasa@unizar.es

[2] Department of Economic Analysis, Faculty of Economics and Business Studies, University of Zaragoza, Gran Vía 2, 50005 Zaragoza Spain. Tel: +34 97672213; Fax: +34 976761996. Email: rduarte@unizar.es

[3] Department of Economic Analysis, Faculty of Economics and Business Studies, University of Zaragoza, Gran Vía 2, 50005 Zaragoza Spain. Tel: +34 976 761826; Fax: +34 976761996. Email: jsanchez@unizar.es

ABSTRACT

In recent years, reducing emissions has become one of the main objectives of the European Community Environmental Policy, which sets emission ceilings for each member state (Directive 2001/81/EC). In Spain, the Energy Saving and Efficiency Plan (2011-2020) aims to reduce energy consumption by 2020, pursuant to the methodological recommendations on saving, measurement, and verification by the European Commission. In this context, we assess the long-term environmental impact of certain consumer-oriented measures, using a dynamic Computable General Equilibrium (CGE) model. Specifically, we generate scenarios that follow Spain's strategies, analyzing the impact of efficient technologies on electricity consumption and transport services, on greenhouse gas (GHG) and sulphur oxide (SO_x) emissions. Our results confirm the existence of "rebound effects" and also the role of technology improvements in delivering positive results for the environment.

Keywords: Consumers, Emissions abatement, CGE model, Rebound effect

JEL codes: Q4, Q51, Q56, Q57, C67, C68

KEYWORDS: Please provide up to 5 keywords that apply to your work

1. Introduction

In recent decades, developed countries have made significant investments in technological improvements aiming at increasing energy efficiency. For instance, the majority of electrical appliances sold today in Europe offer significant improvements in energy efficiency, and the promotion of public transport systems, with greater fuel efficiency has played a prominent role in institutional environmental campaigns at the national and international levels. The European Community Environmental Policy sets emissions ceilings for each EU member state (Directive 2012/27/UE). As a consequence, countries organize their contribution to environmental improvement through national strategies to meet these mandates. Spain's Energy Saving and Efficiency Plan (2011-2020) (IDAE, 2011-2020) aims to reduce energy consumption by 20% by 2020, pursuant to the methodological recommendations on saving, measurement, and verification of the European Commission. The Spanish Plan has the objective of improving final energy intensity by 2% year-on-year for the period 2010-2020, focusing efforts on 6 sectors (Industry, Transport; Building (residential and service); Equipment (residential and service); Public Services; and Agriculture and fisheries), with specific measures for each, involving direct, indirect, and end-users.

Concerning emissions abatement, there is a growing recognition that the responsibility for atmospheric emissions lies not only with producers but also with the end users of goods (Lenzen et al., 2007), although the bulk of the discussion in the literature is based on analyzing the effects of changes on the production side, rather than the consumer side.

In this paper, we assess the environmental impact of the Spanish strategy on the consumer side, using a dynamic Computable General Equilibrium (CGE) model calibrated on 2005 Spanish data. Our analysis focuses on the impact on greenhouse gases (GHG) and sulphur oxide (SO_x). Spain's CO_2 emissions increased to around 50% above 1990 levels in 2004 and 2005, while the Kyoto Protocol required a reduction in global emissions of GHG by 8% from 1990 levels between 2008 and 2012.

Specifically, we generate representative scenarios for certain changes on the consumer side consistent with the measures proposed in the Spanish current strategies, analyzing the impact of improvements in electricity savings (for domestic lighting and electrical appliances) and the promotion of efficient modes of transport. With this, we address the following general question: To what extent could an accumulation of many small actions lead to a large reduction of emissions in society as a whole, thus meeting environmental mandates? Put another way, could a mass of small environmental actions by Spanish households have a significant impact on emissions?

Emissions generated in the production process are considered as indirect emissions, linked to the different components of final demand (i.e. households, exports, public expenditure, and investment). Moreover, as has been applied in some studies to calculate environmental impacts using input-output models (e.g. Ferng (2002), Resosudarmo (2003), McDonald and Patterson (2004)), and CGE models (Turner et al., (2012) and Duarte et al. (2014)), emissions generated from heating, cooking, and car use are treated as direct household emissions, depending on the amount and kind of energy used (fuel, gas, coal, etc.).

Our approximation also considers the “rebound” effects (Jevons, 1985), which is usually associated with improvements in energy efficiency. Such improvements alter the mix of both final and input demands, increase consumers’ real income that can result in increasing final consumption. The rebound effect has been broadly studied via CGE models, finding evidence that these effects may lead to reduce the positive environmental results of efficiency improvements (see Hanley et al. (2006) and Anson and Turner (2009) for Scotland, using a dynamic CGE model; Barker et al. (2007) for the UK economy; Barker et al. (2009) for the world economy; Turner and Hanley (2011) for the Scottish economy, and Duarte et al. (2014) for a regional economy in Spain).

Our work benefits from this literature and attempts to go further into the analysis of rebound effects, on electricity use and on the transport sector, through a dynamic model that includes technological progress as a logistic evolution. In this way, we aim to evaluate the proposed sustainable changes in the national strategy to combat climate change.

The rest of the paper is organized as follows. Section 2 presents our methodology and data. Section 3 describes the baseline scenario for the pollution structure of the Spanish economy, our simulations, and the results obtained. Section 4 addresses sensitivity analyses on different assumptions for technological change, emissions data, and elasticity of substitution. Finally, Section 5 presents our concluding remarks.

2. Methodology

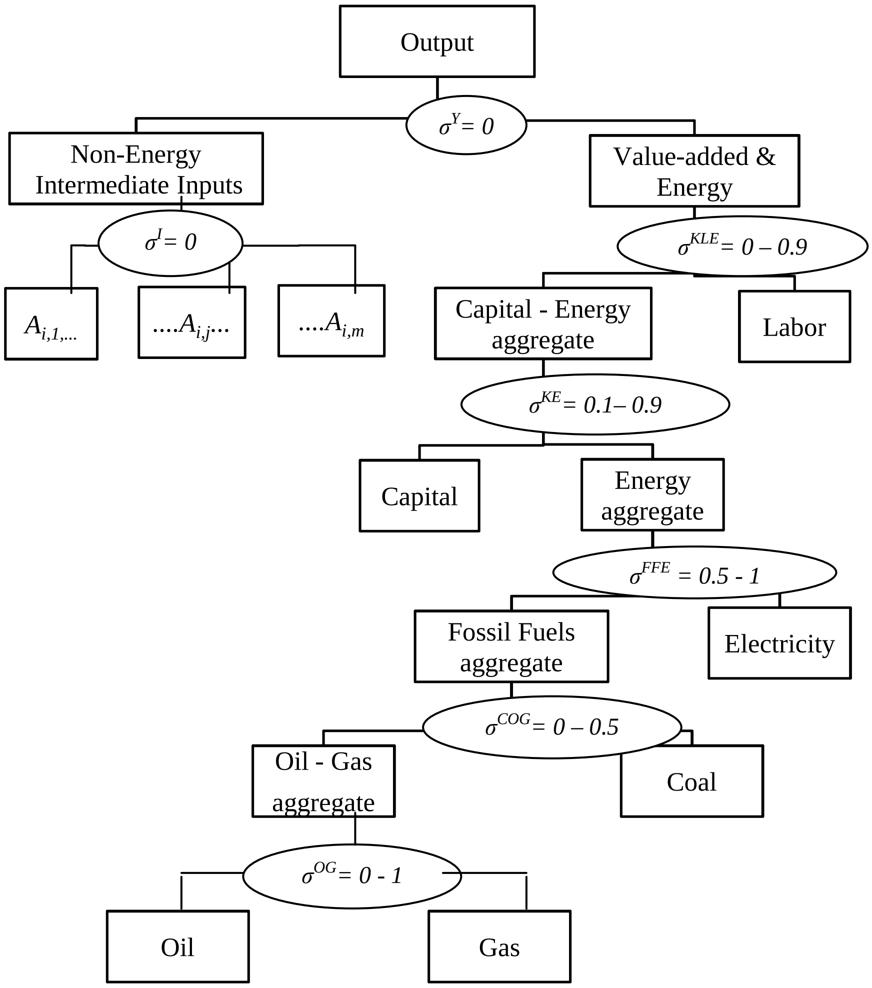
A dynamic CGE model is built and designed for the Spanish economy and calibrated using the Spanish Input-Output Framework (IOFA-05) available in INE (2005a). The input-output table has 34 economic activities, two factors of production (labour and capital), and such other accounts as Households, Companies, Saving/Investment, Government, and a Foreign Sector. The latter consists of two other accounts: transactions carried out with the rest of the European Union (EU), and with the Rest of the World (ROW). In line with the objective of our study, we take a special interest in energy, disaggregated into four sectors: coal, refined petroleum products, electricity, and gas. This high level of disaggregation focusing on sectors linked to energy allows us to consider specific production structures according to certain substitution assumptions.

In our analysis, we develop a multi-sector, recursive dynamic CGE model for the Spanish economy. The structure of the model is described in detail in Duarte et al. (2014), although it is extended dynamically to cover the period 2005-2020. In summary, the model assumes nested Constant Elasticity of Substitution (CES) structures for production and consumption. More specifically, firms minimize their costs and choose the combination of non-energy intermediate inputs and the composite of value-added and energy input (VAE). The aggregate of capital and energy is obtained through a CES combination of the capital factor and the energy composite. In the next stages, nested functions are modeled for the energy selection, as is presented in Figure 1.

Similarly, the selection of the energy goods is included in the consumption side of the model (Figure 2). Consumers maximize the total utility subject to the budget constraint. A nested structure is also adopted regarding the consumer choices with special focus on the energy bundle. The model also includes a wage curve specification which allows us to consider unemployment.

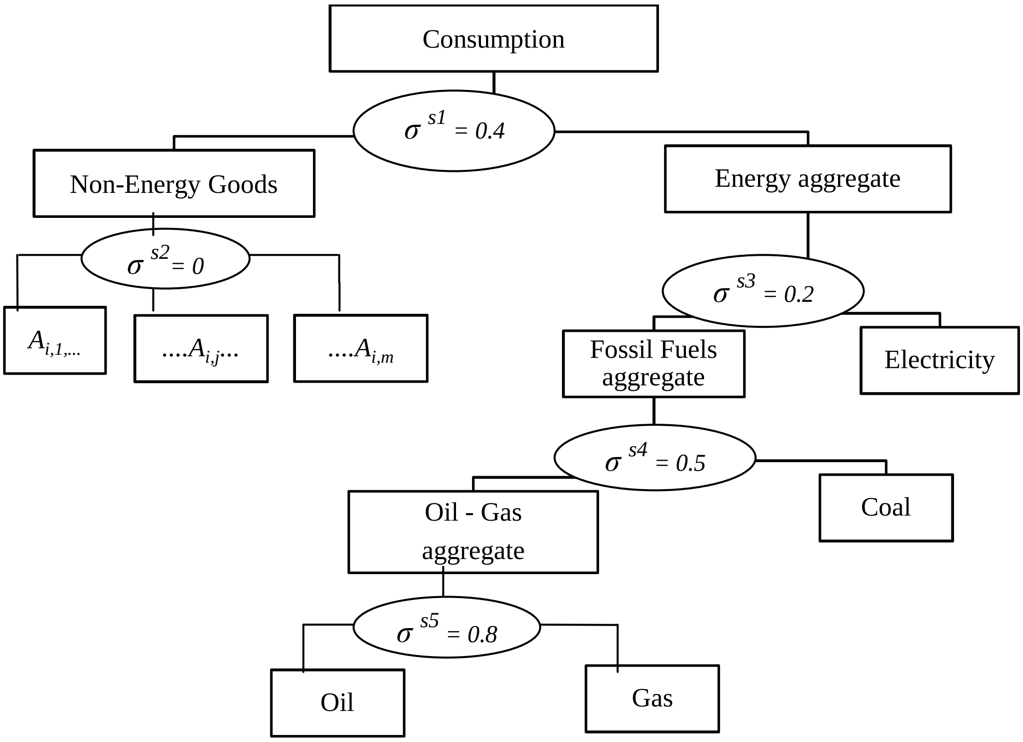
Finally, the elasticity parameters are selected on the basis of a review of the literature on this topic.

Figure 1. Structure of the model



Source: Duarte et al. (2014).

Figure 2. Consumption nesting structure



Source: Duarte et al. (2014).

The model above is calibrated for the Spanish economy, 2005 and dynamically extended for the period 2005-2020 following Paltsev (2000) and Sarasa (2014). The values of the main parameters of the dynamic model are obtained from actual average data for Spain in the period 2005-2013 (INE, 2005-2013). Specifically, the annual interest rate is 4.28% and the growth rate is 0.2%. The relationship between capital and investment in the steady-state is obtained from the calibration of the model using the information of the Spanish input-output table. The model is programmed as a mixed complementarity problem (MCP) using GAMS/MPSGE and is solved with the PATH algorithm.

Once the main economic and environmental impacts are obtained, the input-output model is used in the attribution of emissions to final demand (see also Turner et al., or Duarte et al., 2014). In this regard, the emissions estimated in the simulations take into account both household direct emissions, and direct and indirect emissions from production activities.

$$E^{TOT} = E^{DH} + E^{DIA}$$

Where E^{TOT} are total emissions, E^{DH} are household direct emissions, and E^{DIA} are direct and indirect emissions from all economic activities. The first component, i.e., the emissions resulting from household direct energy consumption (E^{DH}) refers to the emissions per type of energy (“Coal”, “Refined oil” and “Gas”) consumed[1]. The second component (E^{DIA}), captures the emissions that occur during the production process (domestic and foreign) and that are embodied in goods and services consumed by Spanish households. We use an input-output model to relate emissions from production activities to activity levels, applying the following expression (see Sanchez-Chóliz et al. 2007):

$$E = \mathbf{d}' (\mathbf{I}-\mathbf{A})^{-1}\mathbf{s}$$

where **d** is a vector of emissions intensities (Kt of CO_{2eq} and SO_x per monetary unit of output); $(\mathbf{I}-\mathbf{A})^{-1}$ is the Leontief inverse matrix, and **s** is the vector of final demand.

We consider greenhouse gases (GHG) and sulphur oxide (SO_x). The greenhouse gases comprise carbon dioxide (CO_2), methane (CH_4), nitrogen monoxide (N_2O), sulphur hexafluoride (SF_6), hydrofluorocarbons, and perfluorocarbons.GHG emissions are expressed in kilotons of equivalent carbon dioxide (Kt of CO_{2eq}), using the Global Warming Potential published in IPCC (2007). Primary information on emissions has been obtained from the Emissions satellite accounts provided by the Spanish National Statistics Institute (INE, 2005b)[2].

3. Results

Once the CGE model and the calibration are explained, we proceed to simulate alternative changes in the structure of private consumption through technological improvements. These changes provoke changes in the current prices of goods and services, and in the behavior of economic agents, defining a new equilibrium. We quantify their impacts by comparing the new equilibrium with the baseline scenario.

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[1] Electricity consumption is not included, because statistically, in Spain, its emissions are attributed to the electricity sector in their entirety.

[2] However, we conduct a sensitivity analysis to approximate to the emissions data by 2020 in Section 4 in order to observe potential differences in results.

3.1. Description of the baseline scenario

The direct and indirect emissions associated with this scenario are presented in Table 1. The embodied emissions are obtained using the input-output model and the above equation. Economic activities account for more than 84% of GHG and SO_x emissions. Within this, emissions associated with households (embodied emissions) are the most significant; 189,903 Kt of CO_{2eq} and 668 Kt of SO_x. Clearly, household indirect emissions far outweigh their direct emissions.

Emissions from “Electricity”, “Agriculture, forestry and aquaculture”, “Non-metallic and mineral products”, “Transport services” and “Refined petroleum products” comprise mainly GHG and SO_x emissions (see Table A1 of Appendix A). Specifically, the electricity sector accounts for 101,355 Kt of CO_{2eq}, representing 20.08% of GHG emissions, and 848,051 Kt of SO_x, representing 64.31% of SO_x emissions. Meanwhile, emissions associated with transport use, such as “Refined petroleum products” and “Transport services”, account for 55,034 Kt of CO_{2eq}, representing 10.09% of GHG emissions, and 171,393 Kt of SO_x, representing 12.99% of SO_x emissions. Therefore, changes in both electricity and transport use by households may have a significant impact in terms of emissions.

Table 1. Spanish GHG and SOx emissions in baseline scenario

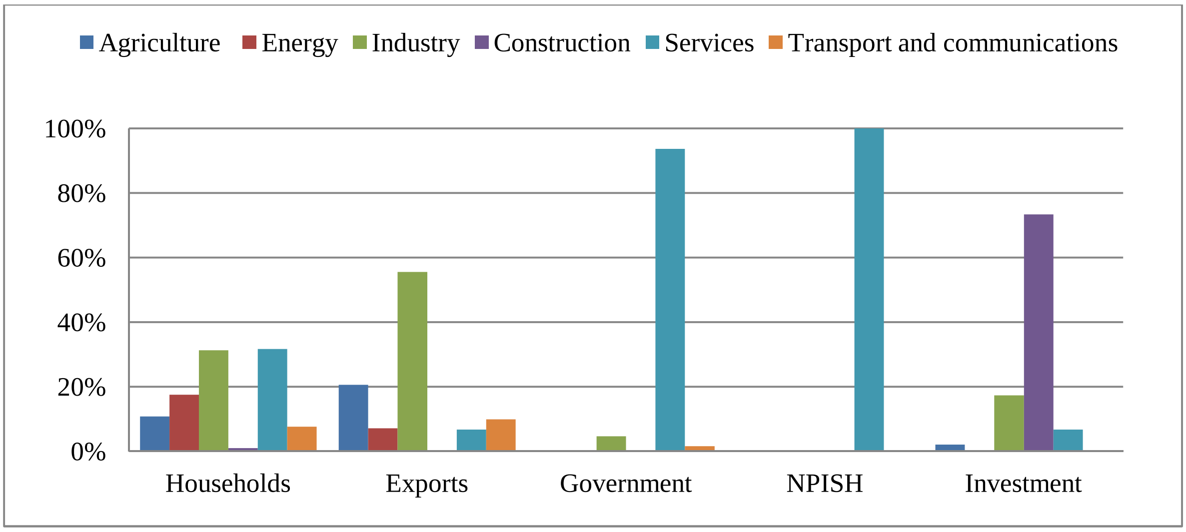
	GHG (Kt)	%	SO_x(Kt)	%
Household direct emissions (1)	77,084	*15.41*	19	*1.42*
Emissions of production activities (2)	422,988	*84.59*	1,300	*98.58*
Households	189,903	*37.98*	668	*50.68*
Export	84,585	*16.91*	255	*19.37*
Government	61,821	*12.36*	129	*9.81*
NPISH	3,477	*0.70*	6	*0.49*
Investment	83,202	*16.64*	240	*18.23*
Total emissions (1+2)	**500,072**	***100.00***	**1,319**	***100.00***

Source: Own elaboration.

The productive pollution structure of each component of Spanish final demand by product group is shown in Figures 3 and 4. In Figure 3, it is clear that GHG emissions associated with household consumption are mainly due to the “Energy”, ”Industry” and ”Services” sectors. The importance of “Services” is primarily for their share in total consumption, while “Agriculture” and “Industry” represent a significantly larger share of emissions attributable to exports, and by contrast, “Energy” and “Services” contribute less. Finally, Government and NPISH emissions are explained by the consumption of services (education and health), and those associated with investment arise mostly from “Construction”.

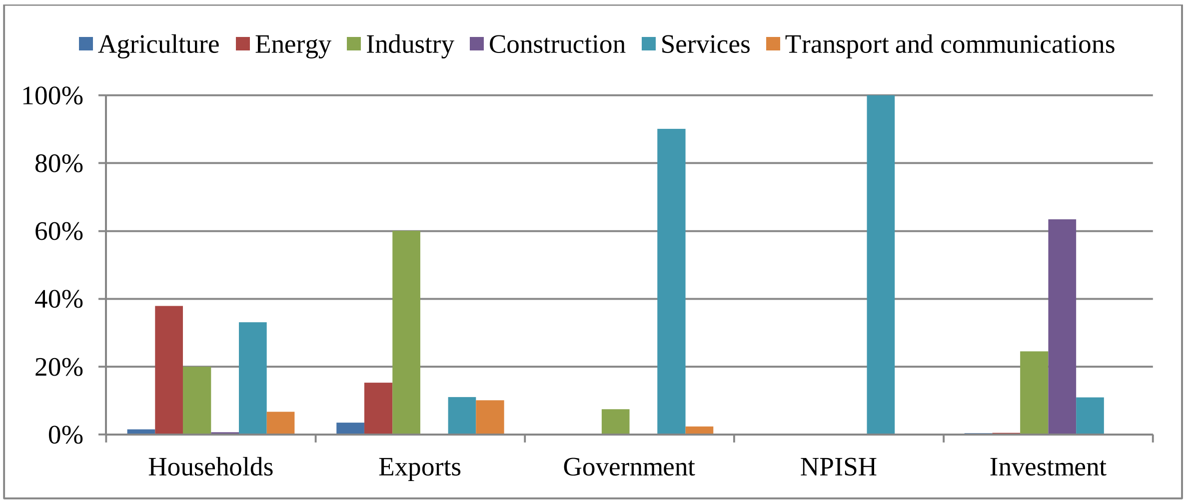
The SO_x emissions in Figure 4 reveal a very different structure. In private consumption and exports, a greater share of emissions are associated with the “Energy” sector, while the structure of SO_x emissions for the rest of final demand is very similar to that of GHG emissions. These differences are only in the emissions intensity of each economic activity, as the composition of demand is identical in both cases.

Figure 3. Structure of GHG emissions associated with Spanish final demand (%)



Source: Own elaboration.

Figure 4. Structure of SO_x emissions associated with Spanish final demand (%)



Source: Own elaboration.

3.2. Description of scenarios

In line with the objectives stated above, we simulate the following scenarios[3]:

- **Scenario 1:** We represent an electricity saving in the domestic sector, achieved through improvement in household energy use efficiency. Thus, we simulate measures such as the replacement of obsolete or low-efficiency domestic devices by appliances labeled Class A or higher, or turning down air conditioning or heating, or not leaving appliances on stand-by, using energy saving light bulbs, etc.
- **Scenario 2:** We simulate a change in the transportation mode of citizens. This scenario again models an improvement in efficiency, with the ultimate objective of improving mobility by fostering more efficient modes of transport. Technological changes occur in *Transport services* and *Petroleum products* as a consequence of expansion and improvement in the use of these sectors[4].

In both scenarios, we consider generalization of efficiency improvement as a learning process. Thus, we consider a logistic evolution following a Gompertz function, to represent the gradual upward improvement from 2005 to 2020 as a consequence of the implementation of Spanish measures simulated in Scenarios 1 and 2. We assume that generalization of improvements among citizens is low at the outset, with a temporal progression characterized by an intermediate acceleration and a smooth growth after a certain number of periods. This assumption allows us to better evaluate the rebound effects triggered by technical change, in line with the rebound literature in CGE models.

3.3. Results of simulations

Tables 2, 3, 4 and Table A2 of Appendix A show the effects of gradual technological improvements in the electricity and transport sectors. As the Energy Saving and Efficiency Plan (2011-2020) aims to reduce emissions by 2020, we assess whether the

[3] Actions included in these scenarios are reported by European citizens as the most common energy-related actions carried out for environmental reasons (Eurobarometer, 2008). In fact, 47% of European citizens in the survey reported one or more of the actions in Scenario 1 to reduce energy consumption, and 28% reported one or more of the actions in Scenario 2.

[4] The improvement is also included in the use of “Petroleum products” due to more efficient machines using less fuel.

conditions can be satisfied by the year 2020. We present the results as a comparison of the baseline scenario in 2020. (The baseline scenario is a steady state with a 2020 time horizon, in which the economy is assumed to be on a balanced growth path without technological improvements.)

Table 2 shows that an improvement in efficiency in electricity provokes an initial saving of electricity consumption of 20.280% by 2020, and an increase in demand for non-electrical goods, which in turn increases total private consumption, by 0.466%, and the associated consumption of the electricity sector at the same time. Electricity sector trade is also reduced. We observe a fall in electricity generation of 4.605% and a small increase in the price of power (0.062%), as well as declines in total exports and imports. However, the welfare level of the economy is enhanced, total output increases, and the unemployment rate declines.

Table 2 also presents the effects on the environment. A technological improvement in the electricity sector leads to a total reduction of 0.880% in GHG emissions by 2020 and 3.196% in SO_x emissions, representing a cut of 4,576 Kt of CO_{2eq} and 43.422 Kt of SO_x (see Table 4). However, we also find an increase of 0.403% in household direct emissions as a consequence of the rebound effects triggered by electricity savings, which increases the consumption of coal, gas, and refined petroleum products.[5] Thus, reductions in total emissions are due to cuts in emissions of production activities. Reductions in SO_x emissions are greater than in GHG emissions due to those emissions associated with the electricity sector representing a larger share of the total SO_x emissions, than in the case of GHG emissions (see Table A1 of the Appendix A, 64.31% of SO_x emissions versus 20.08% of GHG emissions).

[5]The overall change in GHG and SO_x emissions is the same, since it is measured as a percentage change with respect to the baseline scenario. These variations depend on the elasticities of substitution in the consumption function. Note that the amount of emissions variations is different, see Table 4.

Table 2. Effects of improvements in electricity in 2020 (% change with respect to the baseline scenario)

Macroeconomic results	2020	Sectoral & emissions results	2020
Total production	0.068	Electricity production	-4.605
Total imports	-0.108	Electricity consumption	-20.280
Total exports	-0.182	Electricity price	0.062
Total private consumption	0.466	Electricity imports	-4.434
Capital investment	0.000	Electricity exports	-4.776
Government	0.000	Household direct emission (GHG)	0.403
Unemployment	-1.941	Household direct emission (SOx)	0.403
Wages	-0.155	Emissions of production activities (GHG)	-1.128
Exchange rate	0.000	Emissions of production activities (SO_X)	-3.248
Welfare level	0.233	**Total emissions (GHG)**	**-0.880**
CPI	-0.292	**Total emissions (SOx)**	**-3.196**

Source: Own elaboration.

More efficient modes of transport lead to an increase in demand for non-transport goods and non-fuel products that, in turn, increases total private consumption considerably, by 2.6%, as can be seen in Table 3. Again, we observe a decline in transport and in petroleum production and consumption. We can also see that improvements in the transportation sectors produce different degrees of reduction in the consumption of transport services, and of fuel, due to the rebound effects that encourage consumption, and varying with the value of the elasticity of substitution of each product (see Figure 2). As in Scenario 1, the use of more efficient modes of transport and the associated global technological change imply an increase in total production from the economy as a whole, 0.35%, and enhances the general economic welfare. Moreover, we see that, in this case, the decline in unemployment is greater than in Scenario 1, due to larger declines in wages and the consumer price index.

Regarding environmental impacts, technological improvements in sectors linked to transport services lead to a total reduction of 2.706% in GHG emissions by 2020, and 0.588% in SO_x emissions, representing 14,078 Kt of CO_{2eq} and 7.993 Kt of SO_x, respectively (see Table 4). In this case, the fall in emissions is greater for GHG than for SO_x, largely due to the decline in transport services consumption, which is responsible for a larger share of GHG emissions (6.85%) than SO_x emissions (4.10%). More interestingly, we observe that, along with improvements in the transport sectors, we also obtain reductions in household direct emissions, stemming from reductions in refined petroleum products, unlike what we see in Scenario 1.

Table 3. Effects of improvements in transport in 2020 (% change with respect to the baseline scenario)

Macroeconomic results	2020	Sectoral & emissions results	2020
Total production	0.350	Transport services production	-6.890
Total imports	0.759	Transport services consumption	-23.149
Total exports	0.447	Transport services price	0.145
Total private consumption	2.600	Refined petroleum production	-6.278
Capital investment	0.000	Refined petroleum consumption	-16.724
Government	0.000	Refined petroleum price	0.108
Unemployment	-9.452	Household direct emissions (GHG)	-16.004
Wages	-1.108	Household direct emissions (SOx)	-16.004
Exchange rate	0.000	Emissions of production activities (GHG)	-0.134
Welfare level	1.300	Emissions of production activities (SOx)	-0.365
CPI	-1.793	**Total emissions (GHG)**	**-2.706**
		Total emissions (SOx)	**-0.588**

Source: Own elaboration.

To sum up, achieving global technological improvements through more efficient domestic devices, and improvements in transportation, reduces total GHG and SO_x emissions, as expected, and would satisfy the Spanish strategy for year 2020.

To shed more light on the importance of rebound effects, Table 4 disaggregates results by main accounts, and shows that improvements in the electricity sector (Scenario 1) lead to reductions in total emissions (GHG and SO_x), mainly due to reductions in emissions from production activity, specifically in household indirect emissions associated with electricity consumption (5,422 Kt of CO_{2eq} and 43.857 Kt of SO_x), which then provokes a rebound effect in other products and services, causing household indirect emissions to increase by 549 Kt of CO_{2eq} and 1.354 Kt of SO_x, and increases in households direct emissions due to increased consumption of coal, gas, and refined petroleum products, amounting to around 340 Kt of CO_{2eq}. We observe that the reduction in emissions from exports is due to cuts in electricity consumption, but also in energy and agriculture (see Table A2 of Appendix A). Finally, emissions associated with government and NPISH arise from the consumption of services (education and health), and those associated with investment come mostly from the construction sector. Note that, even though government consumption does not change, the emissions associated with government vary due to changes in the Leontief inverse matrix (see Section 2.3).

In the case of Scenario 2, with improvements in transport sectors, reductions in total emissions (GHG and SO_x) come primarily from household direct emissions, as a consequence of reductions in consumption of refined petroleum products (12,049 Kt of CO_{2eq} and 2.766 Kt of SO_x). In addition, emissions from production activity are reduced because of declines in household indirect emissions associated with transport consumption (3,484 Kt of CO_{2eq} and 10.825 Kt of SO_x). However, the rebound effect in other products and services, causing increases in household indirect emissions, is quite large (2,654 Kt of CO_{2eq} and 3.071 Kt of SO_x). Table A2 of Appendix A shows that reductions in emissions from exports are due to declines in transport, energy, and agriculture. Finally, emissions associated with government and NPISH arise from the consumption of services (education and health), and those associated with investment are due mostly to the construction sector.

A comparison of Scenarios 1 and 2 underlines the sensitivity of the rebound effect to elasticity values, as we analyze in the following section. With a similar reduction in the household bill in both scenarios, the rebound effects are quite different and the environmental consequences can vary considerably. Note that, in Scenario 2, environmental effects can be negative if there are no reductions in fuel consumption, and reductions in household indirect emissions are insufficient to offset a potential increase in household direct emissions.

Table 4. Effects on atmospheric emissions in 2020

	GHG (Kt)		**SOx (Kt)**	
	Sce1	**Sce2**	**Sce1**	**Sce2**
Household direct emissions (1)	**340**	**-13,494**	**0.078**	**-3.098**
Coal	1	-16	0.000	-0.004
Refined petroleum products	294	-12,049	0.067	-2.766
Gas	45	-1,430	0.010	-0.328
Emissions from production activity (2)	**-4,916**	**-583**	**-43.500**	**-4.895**
Households	-4,819	-253	-42.366	-3.107
Electricity	-5,422	576	-43.857	4.647
Transport	53	-3,484	0.137	-10.825
Other products and services	549	2,654	1.354	3.071
Export	-41	-259	-0.671	-1.094
Government	-33	-55	-0.258	-0.444
NPISH	-2	-3	-0.013	-0.023
Investment	-21	-14	-0.192	-0.227
Total emissions (1+2)	**-4,576**	**-14,078**	**-43.422**	**-7.993**

Source: Own elaboration.

4. Sensitivity analyses

It is possible that the above results are affected by different sources of uncertainty (Lenzen et al. 20013) and for a robustness test we conduct three sensitivity analyses of our assumptions, and some specific features of the model used. First, we assume that the gradual upward improvement (in household energy use or in public transportation modes) follows a Gompertz function, achieving an efficiency improvement by 2020 of around 33.41%. However, this evolution of technological change may be faster or slower; a faster adjustment would reduce emissions, and vice-versa. Second, we assume that our unit vector of emissions (Kt of CO_{2eq} per monetary unit of output) corresponds to 2005 data for the baseline scenario, and this unit vector does not vary, since we do not know the actual number for 2020. However, emissions satellite accounts show a downward trend of emissions from 2005 to 2010, which is expected to continue over time (see INE, 2005b). Thus, we conduct a sentitivity analysis to approximate the emissions satellite accounts by 2020 through the consideration of a decreasing logistic evolution involving a gradual decline in emissions, from 2005 to 2020, of around 40%. Third, in line with the existing CGE literature, we analyze the role of the elasticity of substitution between electricity and the fossil fuels aggregate in the consumption function, as well as the role of elasticities that affect the transport sectors in Scenario 2.

Table 5 shows the emissions abatement with a smoother function, which reaches 18.25% of efficiency by 2020 (around 55% of the previous improvement). The comparison of Tables 2 and 3 with Table 5 shows that a lower level of efficiency (due to a slower process of adjustment to the Spanish goals) involves smaller reductions in total emissions (GHG and SO_x emissions) in both scenarios. A smaller technological improvement leads to a lesser reduction of emissions from production activity, and a lesser increase of household direct emissions as a consequence of the rebound effect in Scenario 1. In the case of Scenario 2, the reduction of household direct emissions is also smaller, due to a lower level of global technological improvement in the use of petroleum products. Again, the difference in the reduction of total emissions is not significant.

Therefore, we can conclude that our Gompertz logistic assumption appears to be valid, since the environmental results are qualitatively similar, with the signs of the impacts being the same for different levels of improvement. However, the more intensive is the change or improvement, the stronger are the impacts.

Table 5. Sensitivity analysis, technology (% change compared with baseline)

	Scenario 1	Difference points with our results (absolute value)	Scenario 2	Difference points with our results (absolute value)
Emissions of production activity (GHG)	-0.671	*0.457*	-0.109	*0.025*
Emissions of production activity (SOx)	-1.943	*1.304*	-0.290	*0.075*
Household direct emissions (GHG)	0.245	*0.158*	-9.597	*6.407*
Household direct emissions (SOx)	0.245	*0.158*	-9.597	*6.407*
Total emissions (GHG)	**-0.522**	*0.358*	**-1.647**	*1.060*
Total emissions (SOx)	**-1.912**	*1.284*	**-0.423**	*0.166*

Source: Own elaboration.

As Table 6 shows, when we assume a gradual decline of emissions from 2005 to 2020, of around 40% in the unit vector of emissions, the environmental results obtained for the year 2020 barely change the results of Scenario 1. The environmental results of Scenario 2 for the case of GHG emissions vary a little more, but they remain on the same trend, even with a greater reduction of expected emissions. Thus, we conclude that our results can be considered robust as there are no significant differences, and in any case, the environmental results would be even more positive.

Table 6. Sensitivity analysis, emissions data (% change compared with baseline)

	Scenario 1	Difference points with our results (absolute value)	Scenario 2	Difference points with our results (absolute value)
Emissions of production activity (GHG)	-1.101	*0.027*	-0.151	*0.017*
Emissions of production activity (SOx)	-3.188	*0.060*	-0.401	*0.036*
Household direct emissions (GHG)	0.403	*0.000*	-16.004	*0.000*
Household direct emissions (SOx)	0.403	*0.000*	-16.004	*0.000*
Total emissions (GHG)	**-0.732**	*0.147*	**-4.034**	*1.328*
Total emissions (SOx)	**-3.103**	*0.093*	**-0.770**	*0.182*

Source: Own elaboration.

Finally, studies using CGE models usually check the sensitivity of the alternative elasticity of substitutions, so we conduct a sensitivity analysis for Scenario 1 on the elasticity of substitution between electricity and the fossil fuels aggregate in the consumption function. Specifically, we increase and reduce the initial value. Then, we conduct another sensitivity analysis for Scenario 2 on the elasticities that affect transport services sectors. In this case, we again increase and reduce the initial values, as shown in Table 7. The values of elasticities influence the strength of the substitution effect, due to changes in the relative prices of the alternatives.

Table 7. Sensitivity analysis of elasticities values (% change compared with baseline)

Baseline: $\sigma^{s3} = 0.2; \sigma^{s2} = 0; \sigma^{s5} = 0.8$	**Scenario 1**		**Scenario 2**	
	$\sigma^{s3} = 0$	$\sigma^{s3} = 0.4$	$\sigma^{s2} = 0$ $\sigma^{s5} = 0.4$	$\sigma^{s2} = 0.2$ $\sigma^{s5} = 1.2$
Emissions of production activity (GHG)	-1.353	-0.833	-0.105	-0.078
Emissions of production activity (SOx)	-3.899	-2.453	-0.267	-0.309
Household direct emissions (GHG)	0.453	0.350	-15.871	-16.070
Household direct emissions (SOx)	0.453	0.350	-15.871	-16.070
Total emissions (GHG)	**-1.060**	**-0.642**	**-2.661**	**-2.670**
Total emissions (SOx)	**-3.837**	**-2.413**	**-0.489**	**-0.534**

Source: Own elaboration.

For the case of Scenario 1, the comparison of Tables 2 and 7 presents only minor differences. Reducing the value of the elasticity, total emissions decline, due to a greater fall in emissions attributed to electricity consumption, which offsets higher emissions in other non-electrical goods and services (also comparing Tables 4 and 8). Increasing the value of elasticity has a smaller impact on the reduction of total emissions as a consequence of a lesser reduction in emissions attributed to electricity consumption, which does not offset the emissions attributed to other non-electrical goods and services. The same trend is observed in Scenario 2 when we compare Tables 3 and 4 with Tables 7 and 9. Moreover, differences in the environmental results are even smaller than in Scenario 1. However, the substitution issue arises as an important factor to consider in any environmental analysis.

In summary, we find the results of our simulations are sufficiently robust - as our three sensitivity analyses show – and that qualitative results do not differ with alternative features for the specification of the technological change, the uncertainty of the emissions data by 2020, and the parameterization of the model.

Table 8. Sensitivity analysis of elasticity value in Scenario 1 (variation in atmospheric emissions)

	GHG (Kt)		SOx (Kt)	
	$\sigma^{s3} = 0$	$\sigma^{s3} = 0.4$	$\sigma^{s3} = 0$	$\sigma^{s3} = 0.4$
Household direct emissions (1)	**382**	**295**	**0.088**	**0.068**
Coal	2	1	0.000	0.000
Refined petroleum products	330	255	0.076	0.059
Gas	51	38	0.012	0.009
Emissions of production activity (2)	**-5,898**	**-3,632**	**-52**	**-33**
Households	-5,861	-3,597	-51.401	-32.289
Electricity	-6,604	-4,176	-53.418	-33.774
Transport	66	49	0.196	0.139
Other products and services	677	530	2	1
Export	-20	-16	-0.690	-0.400
Government	-10	-12	-0.079	-0.098
NPISH	-1	-1	-0.004	-0.005
Investment	-6	-6	-0.056	-0.069
Total emissions (1+2)	**-5,515**	**-3,337**	**-52.142**	**-32.794**

Source: Own elaboration.

Table 9. Sensitivity analysis of elasticities values in Scenario 2 (variation in atmospheric emissions)

	GHG (Kt)		SOx (Kt)	
	$\sigma^{s2} = 0$ $\sigma^{s5} = 0.4$	$\sigma^{s2} = 0.2$ $\sigma^{s5} = 1.2$	$\sigma^{s2} = 0$ $\sigma^{s5} = 0.4$	$\sigma^{s2} = 0.2$ $\sigma^{s5} = 1.2$
Household direct emissions (1)	**-13,382**	**-13,549**	**-3.072**	**-3.111**
Coal	-16	-16	-0.004	-0.004
Refined petroleum products	-13,040	-11,096	-2.994	-2.547
Gas	-327	-2,437	-0.075	-0.560
Emissions of production activity (2)	**-458**	**-340**	**-4**	**-4**
Households	-125	-43	-1.895	-2.758
Electricity	573	598	4.620	4.826
Transport	-3,483	-2,827	-10.816	-8.784
Other products and services	2,786	2,186	4	1
Export	-273	-238	-1.119	-0.823
Government	-43	-43	-0.347	-0.347
NPISH	-2	-2	-0.018	-0.018
Investment	-14	-14	-0.194	-0.194
Total emissions (1+2)	**-13,840**	**-13,890**	**-7**	**-7**

Source: Own elaboration.

5. Conclusions

This paper examines the impact of adopting demand-side environmental strategies for atmospheric emissions in the Spanish economy. To achieve this objective, a dynamic CGE model is calibrated for the economic data from Spain that allows us to evaluate the effects of changes in household consumption patterns by year 2020, in line with the Energy Saving and Efficiency Plan (2011-2020).

The results from the baseline scenario (year 2005) suggest that both SO_x and GHG emissions are concentrated in a very few economic activities, in particular the energy sectors and agriculture, and production activity accounts for more than 80% of GHG and SO_x emissions. Indeed, emissions associated with households and exports (embodied emissions) are the most significant.

As a scenario analysis, we have simulated two measures established in the Energy Saving and Efficiency Plan for Spain, which are directly related to changes in household consumption through technological improvements in household energy use (Scenario 1), and via more efficient modes of transport (Scenario 2). The main insights of this paper can be summarized as follows. First, improvements in efficiency in the electricity and transport sectors drive increases in demand for non-electrical goods (in Scenario 1) and non-transport goods (in Scenario 2), respectively, that expand total consumption. In the case of electricity improvements, total production increases and the unemployment rate falls. In addition, the welfare level of the economy is enhanced. In the case of transportation improvements, we also find increases in total output, exports, and imports by year 2020, and even larger reductions in unemployment rates. More interestingly, both kinds of improvement lead to reductions in total emissions (GHG and SO_x).

Second, policies of electricity savings in households are efficient from an environmental point of view, although it should be noted that we then see increases in GHG and SO_x emissions in household direct emissions, due to the increased consumption of coal, gas, and refined petroleum products from the rebound effect. In this case, renewable resources should be promoted to counteract such increases in emissions. This issue encourages an extension of the current study to address the state of renewable energy in Spain, as well an analysis of methods to reduce the rebound effect.

Third, following our main question at the beginning of the paper, we conclude that many small actions on the part of Spanish households, following the lead of larger strategies that involve the employment of technological improvements in the electricity and transport sectors, can lead to a considerable reduction of emissions in society as a whole. Seen in this light, the voluntary efforts of every citizen should be considered by any politician, and never underestimated.

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Appendix A – Complementary Tables

Table A1. Structure of direct atmospheric emissions in Spain

Economic activity	**GHG (Kt of CO_{2eq})**	**GHG (%)**	**SO_x (Tn)**	**SO_x (%)**
Agriculture, forestry and aquaculture	91,342	*18.09*	16,726	*1.27*
Coal	4,674	*0.93*	19,208	*1.46*
Refined petroleum products	20,434	*4.05*	117,273	*8.89*
Minerals and metals	565	*0.11*	0,012	*0.00*
Non-metallic and mineral products	52,146	*10.33*	64,967	*4.93*
Electricity	101,355	*20.08*	848,051	*64.31*
Gas	9,625	*1.91*	80,511	*6.11*
Water	937	*0.19*	0,000	*0.00*
Meat industry	1,546	*0.31*	2,465	*0.19*
Dairy industry	682	*0.14*	1,088	*0.08*
Other food industries	3,615	*0.72*	5,764	*0.44*
Beverages	1,205	*0.24*	1,921	*0.15*
Tobacco	191	*0.04*	0,305	*0.02*
Textile products	2,603	*0.52*	4,108	*0.31*
Wood and cork	820	*0.16*	1,047	*0.08*
Paper, publishing and printing	4,924	*0.98*	8,088	*0.61*
Chemicals products	12,524	*2.48*	21,605	*1.64*
Plastic and other manufacturing products	781	*0.15*	1,258	*0.10*
Metal products and machinery	17,383	*3.44*	38,195	*2.90*
Transport equipment	2,369	*0.47*	3,977	*0.30*
Construction	5,396	*1.07*	0,148	*0.01*
Recycling	702	*0.14*	0,631	*0.05*
Commercial services	6,539	*1.30*	2,574	*0.20*
Hotels	86	*0.02*	0,041	*0.00*
Restaurants	427	*0.08*	0,206	*0.02*
Transport services	34,600	*6.85*	54,120	*4.10*
Credit and Insurance	455	*0.09*	0,556	*0.04*
Real estate	356	*0.07*	0,435	*0.03*
Private education	22	*0.00*	0,027	*0.00*
Private health	1,266	*0.25*	0,290	*0.02*
Other sales-oriented services	0	*0.00*	0,000	*0.00*
Public education	22	*0.00*	0,027	*0.00*
Public health	1,266	*0.25*	0,290	*0.02*
Public services	42,131	*8.35*	3,970	*0.30*
Households	81,827	*16.21*	18,785	*1.42*
TOTAL	504,816	*100.00*	1.318,666	*100.00*

Source: Own elaboration.

Table A2. Variations on atmospheric emissions associated with final demand in 2020

Scenario 1	**GHG**					**SOx**				
	Households	**Exports**	**Government**	**NPISH**	**Investment**	**Households**	**Exports**	**Government**	**NPISH**	**Investment**
Agriculture	79.289	-19.121	0.000	0.000	-0.477	0.029	-0.020	0.000	0.000	-0.001
Energy	24.273	-41.363	0.000	0.000	-0.163	0.142	-0.243	0.000	0.000	-0.001
Electricity	-5421.590	-87.356	0.000	0.000	0.001	-43.857	-0.707	0.000	0.000	0.000
Industry	218.662	89.182	-2.803	0.000	0.883	0.450	0.253	-0.017	0.000	-0.018
Construction	7.009	0.000	0.000	0.000	-18.416	0.014	0.000	0.000	0.000	-0.150
Services	219.587	8.393	-30.114	-1.697	-2.676	0.718	0.031	14.523	-0.013	-0.021
Transport and communications	53.314	9.632	-0.486	0.000	-0.051	0.137	0.014	-0.003	0.000	0.000
TOTAL	**-4819.456**	**-40.632**	**-33.403**	**-1.697**	**-20.899**	**-42.366**	**-0.671**	**14.503**	**-0.013**	**-0.192**

Scenario 2	**GHG**					**SOx**				
	Households	**Exports**	**Government**	**NPISH**	**Investment**	**Households**	**Exports**	**Government**	**NPISH**	**Investment**
Agriculture	524.135	-117.573	0.000	0.000	-0.740	0.249	-0.075	0.000	0.000	-0.002
Energy	-965.717	-298.640	0.000	0.000	-0.258	-6.106	-1.715	0.000	0.000	-0.001
Electricity	576.388	-10.800	0.000	0.000	0.003	4.647	-0.088	0.000	0.000	0.000
Industry	1527.479	708.610	-2.836	0.000	15.894	3.391	2.380	-0.020	0.000	0.040
Construction	46.744	0.007	0.000	0.000	-24.610	0.112	0.000	0.000	0.000	-0.229
Services	1521.227	66.462	-51.379	-2.862	-3.732	5.424	0.309	-0.418	-0.023	-0.034
Transport and communications	-3483.727	-606.727	-0.748	0.000	-0.078	-10.825	-1.904	-0.006	0.000	-0.001
TOTAL	**-253.471**	**-258.662**	**-54.963**	**-2.862**	**-13.521**	**-3.107**	**-1.094**	**-0.444**	**-0.023**	**-0.227**

Source: Own elaboration.

Regulatory trade-off between encouraging the improvement of technical quality and recognition of operating and capital costs on the distribution network operators in Brazil

Samuel J. C. Vieira[1,1], Nivalde de Castro[2], Andre L. S. Leite[3]

[1] *ENERGISA.SA – Federal University of Rio de Janeiro – GESEL – COPE,* *samueljcvieira@gmail.com*

[2] *Federal University of Rio de Janeiro – GESEL, nivalde@ufrj.br*

[3] *Federal University of Santa Catarina – andre.ls.leite@gmail.com*

- **SESSION:** Energy markets and regulation, Regulation and monitoring of energy markets

ABSTRACT

This paper takes the regulatory impact evaluation of the incentive mechanism to improve the technical quality of electricity distributors in Brazil. The methodology proposed by the Brazilian regulatory agency (ANEEL) follows the concept of the mechanism RPI - X know by subtracting the productivity gains in the annual tariff adjustments. Inside the X factor the regulator has created a mechanism that increases the tariff recognition of companies that can improve the quality of service. However, this mechanism does not have an empirical model that corroborates the estimated results and set in a discretionary manner the limits of incentive structure. In this paper we have created an empirical model that confronts the estimated elasticity percentage to increase (or decrease) recognition of costs following a panel fixed effects model. In this statistical model it is possible confront the magnitude of the trade-off in the structure of regulatory incentives linked to the amount of reconnaissance of operation and capital costs. The results indicate that in some underlying criteria the tariff recognition is insufficient to offset the increased costs that ensure the improvement of technical quality in both perspectives: punishment and incentive recognition for operate with better practices, especially in some immature concession areas.

KEYWORDS: Regulation, Technical quality, Benchmarking, OPEX, CAPEX.

[1] Corresponding author.

1. INTRODUCTION

Since the third periodic cycle revisions of the electricity distribution companies in Brazil, the firms can obtain tariff gains case deliver a better quality of service to their customers. The regulatory incentive mechanism adopted is dynamic, ie, greater variations of quality indicators between two consecutive years will be higher tariff appropriation in the next year.

The current regulation does not provide a model that the incentive level for the quality gains is empirically estimated. The applied results are derived from assumptions "*ad-hoc*" limited by the maximum percentage of recognition of +/- 2% per year. The importance of studying this mechanism comes from the fact that the strength of regulatory incentive may be underestimated in two cases: **A)** the punishment for sell a low quality service, and, **B)** the reward for improving services. Both can't express the degree of aversion of society to low-quality services.

Unfortunately this paper will only be considered the company's vision in terms of costs incurred to improve the technical quality of the services. An alternative treatment would add to this approach the vision of consumers against the cost of energy deficit. We don't treat this approach on this paper, however is an important perspective for future studies. The hypothesis to be measure in this paper it will then: "*The mechanism of incentives to improve the technical quality in Brazil corresponds to the opportunity cost of improving the quality of services?*"

To answer the question above, we made a regression analysis with panel data, considering two methodologies: **A)** The first it is a dynamic panel fixed effects as proposed by ARELLANO and BOND (1991). We have the intention to address the problem of inertia in trajectory of reducing costs and connect the estimated incentive to reduce them. With this approach is expected to obtain statistical significance between the incentive to improve the quality and the cost trajectories. This case demonstrated insignificant statistical results. **B)** A second model evaluated removed the autoregressive term and treat the variation of costs responds only with shocks in the panel variables. This model considers the "ceteris paribus" vision only on the quality indicators. This approach proved to be statistical significant. Both models were estimated considering two stages, where the effects of other variables that affect the costs were treated assuming be exogenous. The estimated models, therefore, restricted the quality information when separated. The Premise is not a very strong information that will be compound for a weighted index.

"The results indicate that the regulatory incentive to improve the technical quality of supply energy is undersized in Brazil". Besides this introduction the article is divided into the following sections: **2** – Brazilian model; **3** – Incentive mechanism to improve the quality; **4** – Methodology; **5** – Results; **6** – Conclusions **7** – Conflicts of interest; and **8** – Bibliography.

2. BRASILIAN MODEL

The regulatory and institutional framework of the Brazilian market is based on providing non verticalized services which generation costs and freight costs – transmission and distribution – are separated. The latter two characterized by regulated natural monopolies. On the portion of the distribution revenue acts the incentive mechanism to improve the quality[2].

The regulatory model in Brazil turns the operating conditions of the electricity distributors – provision of infrastructure and quality – in "*drivers*" of costs and simulates the competitive market by techniques of "*benchmarking*". For this the annual adjustment mechanism of tariffs in the regulated distribution market is affected by the performance of companies. The Brazilian mechanism is also one of the most common among regulators in other countries and is the evaluated joint an inflation index adjustment. The X – factor adjusts the retail tariffs annually[3] and this factor is described by

$$X = P_d + T + Q \qquad \mathbf{1}$$

As is known in microeconomic theory, the managerial process in competitive markets is different from that which should be adopted in markets without competition – monopolies – as the interaction of agents becomes not necessarily cooperative. The mechanism of **equation 1** affects competition in the Brazilian electricity sector and the companies start to compete with each other seeking higher tariff margin gains.

The X – factor impose compulsory the sharing of productivity on the regulated tariff simulating the competitive market. It's magnitude depends on the three factors above on **equation 1** that capture different cost drivers: **a) Pd component** – or distribution productivity – is responsible for the sharing of productivity gains on the scale or growth of the concession area, this tends to be positive, ie, it's commonly one tariff reducer; **b) The T component** – or trajectory of operating costs – is responsible for the equalization of operating processes of distribution, identify and apply penalties for not achieving the best operation practices. This component tends to be positive for inefficient firms, also resulting in reduction of tariffs; **c) The Q component** – is responsible for regulatory incentive to improve the quality of service. It tends to be negative for companies that gain efficiency in quality, implicated rate increase when the quality improves, though it may have an impact on rising costs, causing "*trade -off*" especially with T component.

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[2] This portion is known as "portion B" comprises the operation and maintenance costs, and return on investments in distribution systems.

[3] The new indicator that adjusts the tariffs in Brazil is the IPCA - national price index broad consumer - calculated by the Brazilian Institute of Geography and Statistics. Its adoption will take place from 2016 at concessioners to renew their contracts. Before the adjustment was made by the IGP-M – general price index of markets.

In competitive markets when the productivity of a business increase this business is more likely to be successful over time. It can be seen from this that the establishment of regulatory conditions through the "benchmarking" means the removal of a significant degree of comfort to business managers and enforce then act searching better practices.

3. INCENTIVE MECANISM TO IMPROVE THE QUALITY

The mechanism to incentive the improvement of the energy quality in Brazil is applied in the calculation of X – factor according to the sub module 2.5 of PRORET[4]. The component responsible for tariff recognition of improvements in quality of service is described by X_Q factor – or simply Q – where improvements or deteriorations in the quality of service provided to consumers is captured as an increase or reduction of tariffs respectively. For a more detailed description of this mechanism the main references are the technical notes number 67/2015 – SRM / SGT / SRD / ANEEL and number 404/2014 – SRE / ANEEL[5].

Generally speaking the incentive mechanism for quality improvement to distribution system operators with more than 60.000 consumer units[6] is divided into two components:

A. The incentive component improving the Q_T (technical quality), and,

B. The incentive component improved Q_C (commercial quality).

At where:

$$Q = 0{,}70 \times Q_T + 0{,}30 \times Q_C \qquad \mathbf{2}$$

And

$$Q_T = 0{,}50 \times Q_{DEC} + 0{,}20 \times Q_{FEC} \qquad \mathbf{3}$$

$$Q_C = 0{,}10 \times Q_{FER} + 0{,}10 \times Q_{IASC} + 0{,}04 \times Q_{INS} + 0{,}03 \times Q_{IAb} + 0{,}03 \times Q_{ICO} \qquad \mathbf{4}$$

The classification of indicators above is show that, by

[4] Tariff Regulation Procedures, available at: http://www.aneel.gov.br/area.cfm?idArea=702. Only in Portuguese, accessed in14-12-2015.

[5] Avaible at; http://www.aneel.gov.br/, Informações Técnicas > Audiências / Consultas > Audiências Públicas > Audiência Ano 2014 – (Finalizado o período de contribuição em 2015) > Audiência 023/2014, resultados da primeira e segunda fases.

[6] Small distributors have more flexible treatment where the implementation of "Call-centers" and it's optional according to the Art. 184 da REN nº 414/2010.

Indicator	Definition	Regulamentation
DEC	Equivalent duration of interruptions per unit consumer (in hours).	Module 8 of PRODIST[7]
FEC	Equivalent frequency of interruptions per unit consumer (in times).	Module 8 of PRODIST[7]
FER	Equivalent frequency of reclamation for each 1000 consumers.	REN nº 574/2012
IASC	ANEEL index of consumer satisfaction. Results on the degree of consumer satisfaction with the service provided.	-
INS	Reflects the answered calls in call-center on respect for calls received less abandoned.	REN nº 414/2010
IAb	Reflects the list of dropped calls on incoming.	REN nº 414/2010
ICO	Reflects the ratio of busy calls.	REN nº 414/2010

The incentive mechanism for each "driver" of quality has the same quantitative basis. But to make an evaluation of a new incentive mechanism we are limited by available historical data for the treatment of the technical component (Q_T). The commercial component (Q_C) will not be considered on this paper for to two reasons: **1** – have recent regulation, and; **2** – the absence of data for statistical analysis. Anyway, the study of only the technical component corresponds for 70% weight in the estimation of Q component of X – factor.

The regulatory incentive mechanism in the tariff for to improve the DEC (in other words reduce the indicator) – and therefore the FEC – is given as follows in Brazil:

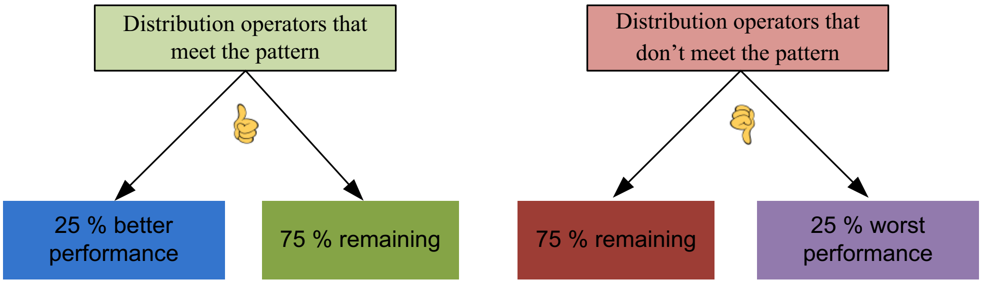
1. The global indicators[8] are computed from adjusting for electrical assembly[9]:
2. After identifying the quality indicators set by electrical assembly we building the individual goals by clustering method using the distance function of the Euclidean technique, where the benchmarks are defined by clusters of 50 to 100 sets from the second decile of box-plot dispersion of comparable values.
3. The individual limits leading to overall limits for distributors where the quality goals that define the pattern of service that being delivered to consumers and are constructed by the weighted sum of the individual indicators.
4. The distributors are separated in large (market ≥ 1 TWh / year) and small companies.

[7] Distribution Procedures, available at em: http://www.aneel.gov.br/area.cfm?idArea=82. Only in Portuguese. Access in 10-12-2015.

[8] The indicator do not consider faults of energy in the transmission system, is the weight sum for each assembly.

[9] The electrical assembly is compound for the electric extensions of a determined electric substation and can include one, many, or only parts of cities.

5. The distributors are divided into two groups in year of analysis: **i** – companies that meet the pattern, i.e. manage to overcome the specific quality goals in item 3, and; **ii** – companies that don´t meet the pattern:



6. Given the two groups of item 4, the distributors are ranked from best to worst effective performance, and classified in sub-groups (Blue, Green, Red and Purple) performance where relationships incentive will be more or less restrictive according to the position of companies in the performance scale compared.
7. Is computed the percentage change between $t-1$ and $t-2$ – two years preceding the year of evaluation – of DEC (Δ% DEC) and FEC (Δ% FEC), for each distributor on the case of technical indicators.
8. The calculated value of the percentage change in the index: $\Delta I\% = (IND_t/IND_{t-1}) - 1$, is applied in the next equations:

Meet the pattern?	Class of performance	Band of variation (DEC or FEC)	Curve Q(ΔI%) in (%)
Yes	25% better	ΔI% ≤ - 25%	$Q(\Delta I\%) = -2{,}0000$
		-25% < ΔI% < 5%	$Q(\Delta I\%) = 0{,}0667 \cdot \Delta I\% - 0{,}333$
		5% < ΔI% < 20%	$Q(\Delta I\%) = 0{,}0267 \cdot \Delta I\% - 0{,}133$
		ΔI% ≥ - 25%	$Q(\Delta I\%) = 0{,}4000$
Yes	75% remaining	ΔI% ≤ - 25%	$Q(\Delta I\%) = -1{,}3000$
		-25% < ΔI% < 5%	$Q(\Delta I\%) = 0{,}0520 \cdot \Delta I\%$
		5% < ΔI% < 20%	$Q(\Delta I\%) = 0{,}0600 \cdot \Delta I\%$
		ΔI% ≥ - 25%	$Q(\Delta I\%) = 1{,}2000$
No	75% remaining	ΔI% ≤ - 25%	$Q(\Delta I\%) = -0{,}9000$
		-25% < ΔI% < 5%	$Q(\Delta I\%) = 0{,}0450 \cdot \Delta I\% - 0{,}225$
		5% < ΔI% < 20%	$Q(\Delta I\%) = 0{,}0640 \cdot \Delta I\% - 0{,}320$
		ΔI% ≥ - 25%	$Q(\Delta I\%) = 1{,}6000$
No	25% worst	ΔI% ≤ - 25%	$Q(\Delta I\%) = -0{,}5000$
		-25% < ΔI% < 5%	$Q(\Delta I\%) = 0{,}0333 \cdot \Delta I\% - 0{,}333$
		5% < ΔI% < 20%	$Q(\Delta I\%) = 0{,}0667 \cdot \Delta I\% - 0{,}667$
		ΔI% ≥ - 25%	$Q(\Delta I\%) = 2{,}0000$

Finally the values calculated in item 8[10] are replaced in **equations 2, 3 and 4**, and applied directly to the X factor on every revenue portion B of the distributors, leading to higher tariff or lower level that reflects the quality performance.

4. METHODOLOGY

4.1. Theoretical discussion

The quality of the optimal level adjustment mechanism is based on many factors that are directly or indirectly on the management of companies. Among the items that most affect the continuity of energy supply are: **i)** exogenous factors related to weather – lightning, rain and wind – **ii)** building pattern of networks, **iii)** the incidence of the practice (still common) of power theft **iv)** the cost of tariffs, which can increase the level of default by consumers, **v)** the conflicting mechanisms of regulatory incentives, especially the requirement to reduce operating costs in companies with low quality. This last is the object of study of this paper.

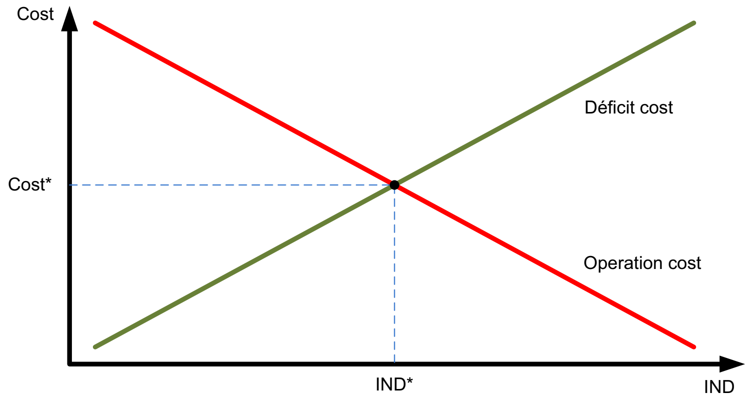
The first item mentioned relates to stochastic events of atmospheric nature there are uncontrollable and unmanageable and generate considerable costs in terms of quality. Added to this perception the constructive pattern of networks and the degree of depreciation of assets, increases the system vulnerability. The power theft reduces the operating capacity of enterprises, leading instability in the supplier. Such factors are condensed on the ability that the concessionary need to have evaluated the capability to pay of their consumer units. In the Brazilian case – particular for some concessions that have socially vulnerable areas – there can be no large proportion of commitment of family income in payment of bills, because which presses the increase in energy theft and default.

On this paper we estimate of empirical reliably relations that indicate the best possible way what the average elasticity for the Brazilian market adjustments that converge in the improvement of quality of service in terms of costs. In a general way these adjustments has the tendency to evidence part of the information needed so that can identify an optimal level of quality.

From the figure below you can see two behaviors based on the amount of quality indicator. The first described the red line shows the company's vision, where the indicator increases – lower quality – lower costs are expended to maintain the service delivery infrastructure. However the

[10] Available at: http://www.aneel.gov.br/arquivos/PDF/Proret_Subm%C3%B3dulo%202.5_V2.pdf. 2.5 module of PRORET, access in 10-12-15.

consumer view is evidenced by the green equation, where the higher the quality – smaller indicator – more costly it becomes to deliver the service. In this case the energy deficit causes economic losses to consumers.



The dynamic equilibrium between the perception of quality by consumers – cost of the deficit – and the actual cost of providing a more reliable service – operating cost – define on the middle an optimal value for the cost for a given concession area.

Generally speaking the red equation can be estimated – and it is about her the study of this article – from operating data of the distribution companies in Brazil. The green equation has set more complex because it depends on the consumer market expectations, energy demand growth and any "*trade-offs*" involving increase in operating costs, the cost of welfare, opportunity or the production of products and services that depend on electricity as irreplaceable input.

The simple model presented above shows the importance of following premise: "*There is a theoretical limit of the operating cost of a concession and the level of quality required by its consumer market*." On this limit none improvement in the quality of service may be appropriate by the concessionaire or by their consumers, causing economic loses and allocative irrationality. The most important restriction of the trajectory for the correlation between cost and quality is the valuation that the consumer units have for the level of quality that are willing to pay.

4.2. Empirical adjustment

Dealt with issues that related to the identification of the efficient cost level compared to quality, it is necessary to indicate how the cost equations and deficit cost can be calculated. Two adjustment assumptions were used on this paper. One considers the inertial effect of other adjustment policies on the level of costs that affect the quality indicators, ie, it was assumed that the cost depends on the cost today a step forward. The second alternative considers only the contemporary impact of quality indicators on the level of cost.

The deficit cost equation – the view of consumers – have relatively complex estimation and the time has not yet formed a consolidated view of how such a relationship could be estimated, considering the specificities of each concession in Brazil. Some ideas already exist to promote this adjustment as estimate, using as a proxy GDP growth, compared to the variation of global indicators for concession. These studies are a continuation of this work, in which it is expected to give more robustness to the analyzes presented.

The cost equation award for quality can be estimated from operational indicators of distribution concessions in Brazil. It was decided to adjust the model containing the inertia parameter using the technique proposed by Arellano and Bond (1991), where the major references on the construction of mathematical assumptions of analysis can be obtained.

According to GREENE (2008), TRIVEDI and CAMERON (2010) the model proposed by ARELLANO and BOND (1991) can be described by the following equations:

$$\begin{aligned} y_{i,t} &= \mathbf{x_{i,t}\beta} + \delta y_{i,t-1} + c_i + \varepsilon_{i,t} \\ &= \mathbf{w_{i,t}\theta} + a_i + \varepsilon_{i,t} \end{aligned} \qquad \mathbf{5}$$

In equation 5 it notes where two equivalent formulations $\mathbf{w_{i,t}}$ presents part of the information contained by $y_{i,t-1}$. In general the dynamic autoregressive term – of interest – is correlated with the error term, said that the estimators of fixed effects, which depend on second WOOLDRIDGE (2006) by the transformation of fixed effects will be inconsistent. Thus the model:

$$y_{i,t} - y_{i,t-1} = (\mathbf{x_{i,t}} - \mathbf{x_{i,t-1}})\boldsymbol{\beta} + \delta(y_{i,t-1} - y_{i,t-2}) + (\varepsilon_{i,t} - \varepsilon_{i,t-1}) \qquad \mathbf{6}$$

Becomes inestimable. Since:

$$E(\varepsilon_{i,t} | \mathbf{x}_{\mathrm{i,t}}\boldsymbol{\beta}) \neq 0 \qquad \mathbf{7}$$

The solution to this problem has been given by applying the generalized moment estimator proposed by HANSEN (1982), where $\mathbf{w_{i,t}}$ capture the effect of $y_{i,t-1}$, leading to consistent estimator. The OLS estimator is biased in this case because: **i)** the fixed effects should not be equal for all companies; **ii)** the explanatory variables are not exogenous especially $y_{i,t-1}$ – there is a direct correlation relationship between costs and quality; and **iii)** the OLS does not allow for serial correlation in the error term; It's precisely to correct this autocorrelation which are included the lagged instruments.

Without this, $y_{i,t-1}$ the set of independent variables included in the model $\mathbf{x_{i,t}}$ is "*all information*" necessary for the estimation of $y_{i,t}$, in this way, any change of dependent variable is expressed by the impact of "*new*" information. So it is observed that the effect of temporal correlation in costs can be "*removed*" from the model so as to subtract only the effect of endogenous variables without temporal correlation. However a most suitable inference process can be built with the exclusion of "*inertial*" term. In this case the $y_{i,t-1}$ may be included as exogenous, if the model is not significant, and a model including only the relationship between the costs and the quality indicator can be estimated by least squares two stages with safety. According to GREENE (2008) the specification of this model would be:

$$\begin{aligned} y_{i,t} &= \mathbf{x_{i,t}\beta} + \mathbf{\alpha h_{i,t}} + \varepsilon_{i,t} \\ &= \mathbf{x_{i,t}\beta} + a_i + \varepsilon_{i,t} \end{aligned} \qquad \mathbf{8}$$

Where it is noted that $y_{i,t}$ does not depend on lagged cost $y_{i,t-1}$. In this case there is no "*inertia*" in $y_{i,t}$. The effects of unknown variables not included $\mathbf{h_{i,t}} = a'_i - \mathbf{\gamma z_{i,t}}$ are treated exogenously.

5. RESULTS

The estimation results of the two models for the DEC and FEC have been calculated from the data of public audience 023/2014 organized by the National Electric Energy Agency[11] (ANEEL). The number of data set consists only of CAPEX values of the second cycle of periodic revisions of power distributors extrapolated to the year 2012 for the third cycle results. Thus the data used in the sample represent a balanced panel from 2005 to 2012, to amount of 61 (of 63) Brazilian power distributors, totaling a sample of 488 observations.

The estimated models take into account the behavior of costs according to the DEC assumption is correlated with TOTEX and the FEC is correlated only with the CAPEX, given the particular nature of each indicator. The DEC depends on the investments and so much of the OPEX, just watch with the duration of interruptions is strongly related to the time spent for repair of power outages, and the FEC is particularly dependent on investments so not be affected by OPEX.

The set of considered instruments included the following variables: Market weighted revenue for each voltage level, kilometers of total network, number of users, FEC performed (DEC performed when the setting involve FEC), a dummy equal to 1 if the FEC performed is lower than the target FEC (or equal to 1 is performed DEC is less than the target DEC, in the case of setting involve FEC). The summary of the adopted models are as follows:

[11] See:

http://www.aneel.gov.br/aplicacoes/audiencia/dspListaDetalhe.cfm?attAnoAud=2014&attIdeFasAud=938&id_area=13&attAnoFasAud=2015 – acessed at 12-12-2015.

i. Relation between the DEC and the TOTEX:

$$\ln(TOTEX)_{i,t} = \mathbf{x}_{i,t}\boldsymbol{\beta_1} + \mathbf{z}_{i,t}\boldsymbol{\beta_2} + \nu_i + \epsilon_i \qquad \mathbf{9}$$

$$\ln(TOTEX)_{i,t} = \boldsymbol{\beta_0}\ln(TOTEX)_{i,t-1} + \mathbf{x}_{i,t}\boldsymbol{\beta_1} + \mathbf{z}_{i,t}\boldsymbol{\beta_2} + \nu_i + \epsilon_i \qquad \mathbf{10}$$

where:

$$\mathbf{x}_{i,t}\boldsymbol{\beta_1} = [\ln(DEC_a) \quad LIM_D] \cdot \begin{bmatrix} \beta_{11} \\ \beta_{12} \end{bmatrix} \qquad \mathbf{11}$$

$$\boldsymbol{z}_{i,t-p}\boldsymbol{\beta_1} = [MP_t \quad REDE_t \quad CONS_t \quad \ln(FEC_a)_t \quad LIM_{F_t}] \cdot \begin{bmatrix} \beta_{21_p} \\ \beta_{22_p} \\ \beta_{23_p} \\ \beta_{24_p} \\ \beta_{25_p} \end{bmatrix} \qquad \mathbf{12}$$

ii. Relation between the FEC and the CAPEX:

$$\ln(CAPEX)_{i,t} = \boldsymbol{x}_{i,t}\boldsymbol{\beta_1} + \boldsymbol{z}_{i,t-p}\boldsymbol{\beta_2} + \nu_i + \epsilon_i \qquad \mathbf{13}$$

$$\ln(CAPEX)_{i,t} = \boldsymbol{\beta_0}\ln(CAPEX)_{i,t-1} + \mathbf{x}_{i,t}\boldsymbol{\beta_1} + \mathbf{z}_{i,t-p}\boldsymbol{\beta_2} + \nu_i + \epsilon_i \qquad \mathbf{14}$$

Where:

$$\boldsymbol{x}_{i,t}\boldsymbol{\beta_1} = [\ln(FEC_a) \quad LIM_F] \cdot \begin{bmatrix} \beta_{11} \\ \beta_{12} \end{bmatrix} \qquad \mathbf{15}$$

$$\boldsymbol{z}_{i,t-p}\boldsymbol{\beta_1} = \left[MP_{t-p} \quad REDE_{t-p} \quad CONS_{t-p} \quad \ln(DEC_a)_{t-p} \quad LIM_{D_{t-p}}\right] \cdot \begin{bmatrix} \beta_{21_p} \\ \beta_{22_p} \\ \beta_{23_p} \\ \beta_{24_p} \\ \beta_{25_p} \end{bmatrix} \qquad \mathbf{16}$$

9 and 13 models are simple panel models, since models 10 and 14 assumes the dynamic argument proposed by ARELLANO and BOND (1991), where the number of lags was chosen in this case to be p = 2. Observing these equations, the expected signal to β_1 coefficient is negative, i.e., if the DEC (FEC) increases costs should fall, revealing a negative substitution ratio.

The $\mathbf{z}_{i,t}\boldsymbol{\beta}_2 = \boldsymbol{\alpha}$ is an intercept term, can have any signal. If negative, it indicates that business costs that reach the targets are on average – X % lower than those who do not reach the goal, revealing that the best quality practices are linked to the best costs practices. If the signal is positive, it indicates that those with better quality on average operating at a higher cost than the average, and for this group the average cost is higher. Thus the results are:

Model	**DEC**		**FEC**	
Est.	Model (9)	Model (10)	Model (13)	Model (14)
L1.TOTEX	0,790*** (0,040)			
L1.CAPEX			0,911*** (0,013)	
ln(DEC)	0,028 (0,026)	-0,342*** (0,065)		
ln(FEC)			0,035*** (0,010)	-0,460*** (0,125)
lim.DEC	0,011 (0,019)	-0,483*** (0,089)		
lim.FEC			-0,020* (0,010)	-0,743*** (0,199)
Cte	2,428*** (0,504)	13,033*** (0,220)	0,929*** (0,157)	12,539*** (0,459)
Prob > F	-	0,000	-	0,000

The above results indicate that the models 10 and 14 on both DEC and for FEC are not significant. That said it is observed that when treated together the term of inertia and quality indicators lack statistical significance. Therefore it is not possible to estimate the elasticity of costs when applying a dynamic model, implying that the trajectory of reducing costs and improving quality indicators not jointly explain the cost level of Brazilian concessions.

One possibility that can't explain the significance of the dynamic model is the lack of observations over time. Then it could be biased by the lack of degrees of freedom. Another important assumption is to assume that there is no correlation between cost reduction and quality improvement trajectories. In this case it would be characterized a significant statistical "*trade-off*" between adjustment strategies that can result in the deterioration of the performance indicators of the regulated businesses.

By comparison models without dynamic terms have great significance. Thus, considering the effect of improving the quality of the costs it is noted that the signs of the estimators are correct and that from them it is possible to estimate the elasticity of substitution between costs and improving quality indicators, without however correlate this impact with cost trajectories. Thus the assumptions of the analyzes that follow are based on the assumption that costs are related to the quality only, regardless of the effects of the derived cost savings from implementation of other components of the X – factor, especially the T component that affects OPEX causing effects on the estimates of the adjustments relative to DEC.

To compare the empirical estimates to the results of the amounts recognized by ANEEL, it takes the average participation of the CAPEX on the distributors in Brazil, weighted by TOTEX between 2005 and 2012 amounting to 47.5%. On this case the elasticities for the estimators of the FEC will be multiplied by this term to reflect the impact of CAPEX on total costs. Comparisons were made with models 9 and 13:

DEC						
Variation	Q ANEEL - Blue	Q ANEEL - Green	Q ANEEL - Red	Q ANEEL - Purple	Model don't meet the pattern	Model meet the pattern
-20%	-1,67	-1,04	-0,90	-1,00	-6,85	-7,33
-15%	-1,33	-0,78	-0,68	-0,83	-5,13	-5,62
-10%	-1,00	-0,52	-0,45	-0,67	-3,42	-3,91
-5%	-0,67	-0,26	-0,23	-0,50	-1,71	-2,19
0%	-0,33	0,00	0,00	-0,33	0,00	-0,48
5%	0,00	0,26	0,23	-0,17	1,71	1,23
10%	0,13	0,60	0,64	0,00	3,42	2,94
15%	0,27	0,90	0,96	0,33	5,13	4,65
20%	0,40	1,20	1,28	0,67	6,85	6,36

FEC						
Variation	Q ANEEL - Blue	Q ANEEL - Green	Q ANEEL - Red	Q ANEEL - Purple	Model don't meet the pattern	Model meet the pattern
-20%	-1,67	-1,04	-0,90	-1,00	-4,37	-5,12
-15%	-1,33	-0,78	-0,68	-0,83	-3,28	-4,02
-10%	-1,00	-0,52	-0,45	-0,67	-2,19	-2,93
-5%	-0,67	-0,26	-0,23	-0,50	-1,09	-1,84
0%	-0,33	0,00	0,00	-0,33	0,00	-0,74
5%	0,00	0,26	0,23	-0,17	1,09	0,35
10%	0,13	0,60	0,64	0,00	2,19	1,44
15%	0,27	0,90	0,96	0,33	3,28	2,54
20%	0,40	1,20	1,28	0,67	4,37	3,63

In the tables above we see that the models estimated by ANEEL recognized – under the analysis of assumptions adopted without the inertial term – *less costs than would be appropriate for the improvement of quality indicators*.

Nevertheless it is noted that both, the empirical reward, and the punishment for breaches of the quality goals are greatly increased. For the most feasible performances between -5% and 5% strong differences are noted. *It is believed in this case that the regulatory incentive is undersized*.

6. CONCLUSIONS

This paper demonstrated that the regulatory incentive to improve the quality of service provided by power distribution utilities in Brazil can be changed in order to provide greater penalties or incentives to improve the quality of service.

The principle of regulatory parsimony can make little regulatory feasible volatilities estimated empirically, when it applies the tariff recognition of companies, either by volatility in tariffs factors, whether the eventual extraction of the tariff increases for tariff setting methodologies.

It is noteworthy that the proposed results are not limited to the treatment of other regulatory incentives involving a reduction in operating costs, which are ultimately important sources of "*trade-offs*" particularly in the case of DEC.

It is characterized unless the restrictions of statistically significant model used to analyze the regulatory incentive introduced in Brazil to improve quality indicators is not enough to "*offset*" the expenses incurred by the distributors in improving the technical quality indicators in the short term.

In the long run it is important to point it out that the regulatory incentive to improve the quality must tend to be zero, "backed the operational characteristics of the companies and exogenous factors that affect the quality such as the weather." This is important as there are operators that can serve as a reference for others in more mature concession areas. The concessions tend dynamically become saturated when its quality index going to stationary state.

Thus the benchmark of quality is not actually bad, but it needs to capture the short-term needs of the less mature concession areas, especially where there is still much work to be done for yours difficulties. The economic and financial balance of concessions can't be threatened by performance awards that do not face the same short-term improvement challenges.

7. CONFLICTS OF INTEREST

The opinions described on this academic work don't represent the institutional view of ENERGISA Group, shareholders, managers and controllers.

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Development of Smart Grids in Brazil: a multi-level perspective analysis

Guilherme Dantas[1], Caetano Penna[2], Pedro Vardiero[3], Rubens Rosental[4], Maria Alice Espinola[5]

[1] Gesel (Electrical Sector Studies Group), Federal University of Rio de Janeiro, Av. Pasteur, 250 Palácio Universitário, Rio de Janeiro, Brazil, e-mail: guilhermecrvgr@yahoo.com.br
[2] Gesel (Electrical Sector Studies Group), Federal University of Rio de Janeiro, Av. Pasteur, 250 Palácio Universitário, Rio de Janeiro, Brazil, e-mail: caetano.penna@gmail.com
[3] Gesel (Electrical Sector Studies Group), Federal University of Rio de Janeiro, Av. Pasteur, 250 Palácio Universitário, Rio de Janeiro, Brazil, e-mail: pvardiero@hotmail.com
[3] Gesel (Electrical Sector Studies Group), Federal University of Rio de Janeiro, Av. Pasteur, 250 Palácio Universitário, Rio de Janeiro, Brazil, e-mail: rubens.rosental@gmail.com
[3] Gesel (Electrical Sector Studies Group), Federal University of Rio de Janeiro, Av. Pasteur, 250 Palácio Universitário, Rio de Janeiro, Brazil, e-mail: maliceem@yahoo.com.br

ABSTRACT

The development of smart grids is a complex, multidimensional process, which contemplates the emergence of new technologies, their dissemination and social acceptance, and also a difficult market-creation phase. Such process is therefore better understood through an interdisciplinary approach. In recent years, the approach of the multilevel perspective (MLP) has gained acceptance as an explanatory dynamic methodology of technological transitions; it is based on the concepts of socio-technological regimes, niches and "landscapes". The purpose of this paper is to analyze the smart grids in Brazil based on the theoretical framework multi-level perspective. The analysis of the status quo and perspectives of development of smart grids in Brazil requires prior knowledge of the motivations and challenges involved. The Brazilian landscape in which smart grids are embedded points to efficiency gains, to the promotion of a more reliable system, and to higher quality as key drivers for the transition, in a context of significant growth in demand. But, it is noteworthy that the current regulatory framework does not encourage investment in network modernization (development of smart grids). Thus, existing smart grid projects in Brazil are currently restricted to early-stage research and development projects, particularly pilot projects.

KEYWORDS: smart grid, smart meter, regulation, projects, policies, multi-level perspective

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1 - INTRODUCTION

The development of smart grid consists of a central element in the dynamics of transformation of the electricity sector in order to meet the growing demand for electricity with safety, quality and sustainability. Although such networks are not an end in themselves, they create necessary conditions for the electrical systems to become more distributed without compromising the security of supply and at the same time, where consumers have a more active behaviour in the management of demand for energy. However, the techno-economic characteristics of the electricity sector (capital-intensive, undifferentiated product, regulated tariffs, inelastic demand, need for instant balance between supply and demand, etc.) do not induce the innovation process to occur endogenously. Therefore, there is a need to adopt public policies to promote investments in the development and the diffusion of innovation such as smart grids.

In Brazil, the development of intelligent networks is still at a very early stage, with incentives restricted to financing pilot projects. In other words, Brazil presents ad hoc initiatives, coupled with insufficient and thus ineffective policies for the implementation of smart grids. Besides the need to improve the quality of service, the need to reduce non-technical losses is a great motivation for investments in smart grids for many distributors. The purpose of this article is precisely to examine the smart grids development prospects in Brazil, considering the characteristics of the existing system and the pressures exerted on it. At the same time, it examines the niches where one can develop and implement smart grid solutions in Brazil.

The development of smart grids is not merely a technological innovation. It is a technological transition, because a new technology will substitute for the incumbent one. It is therefore necessary to examine all the multidimensional variables present in this evolutionary process such as the organizational environment, the institutions involved and especially the interests of different stakeholders in the process. Our study applies the multilevel perspective (MLP) (Geels, 2005a; 2005b; 2012; Markard and Truffer, 2008) to the Brazilian case, which is an adequate approach to analyse the dynamics of technological transitions.

2 – SMART GRIDS AND TECHNOLOGY TRANSITION OF POWER SECTOR

The development of smart grids is complex which contemplates the emergence of new technologies, their dissemination and social acceptance, and also a difficult market-creation phase. Such process is therefore better understood through an interdisciplinary approach. Therefore, it is adequate to use the analytical framework of technological transition on the analysis of smart grids. This approach enables the identification of a set of challenges for policy makers. Strictly speaking, the framework is concerned not with the potential of a new technology itself, but with how this potentiality can be materialized and realized against the advantages of the incumbent technology (Jacobsson and Bergek, 2004).

The following features allow one to analyse the development of smart grids as a process of technological transition:

i. The technologies associated with smart grids can be analysed as an emerging technological system, with the set of emerging technologies associated with smart grids challenging incumbent technologies;

ii. The international literature on smart grids recognizes that this is a long term project, with several full implementation goals by the year 2030. It is therefore a project of slow implementation;

iii. Already there are networks and coalitions of interest around the technologies of smart grids;

iv. Cases of imminent success in relation to smart grid projects are strongly associated with the institutional framework created to develop and disseminate technology.

Although the Technological Systems consists of a very consistent approach to examine the interaction between actors, networks and institutions within the scope of the dynamics of innovation, it is important to emphasize that this approach does not provide a clear distinction between incremental innovations and radical innovations (Markard and Truffer, 2008). Therefore, there is a limitation on this theoretical framework for dealing with technological transitions, i.e. the change from one system to another.

Since the technological transition is the change in a larger system, it is noticeable that it is not confined to the technological sphere and one must consider the presence of lock-in around the existing system. This lock-in is derived from the advantages and / or economic interests of the firms established on the basis of current technological paradigm: core competences on related technologies, built infrastructure, organizational arrangements established standards and consumer preferences (Geels, 2005a).

In summary, the roots of lock in in the electricity industry transcends the supply chain industry where the technology is used. Therefore, the examination of Technological Transition cannot be restricted to comparing alternative technologies in terms of technical efficiency because nothing guarantees that a demonstrably superior technology will be able to overcome initial socio-economic barriers and diffuse in the market. Thus, the process of "locking out" that will ultimately enable the technological transition necessarily involves the consideration of economic, organizational, institutional and cultural variables. Among the possibilities that can trigger lock out, Cowan and Hulten (1996) highlight a possible crisis in the current technological system, adoption of new regulatory guidelines, a technological breakthrough, changes in consumer preferences, the existence of niche markets and the results of scientific research.

3 – ANALYTICAL FRAMEWORK: THE MULTI-LEVEL PERSPECTIVE

In recent years, the approach of multilevel perspective has been gaining space as an explanatory dynamic methodology of technology transition based on the concepts of socio-technical regimes, niches and "landscapes". Briefly, this theoretical framework considers that technological transitions are not a linear process; they occur due to the interaction between the changes in the micro-level of the niches and the meso-level of socio-technological regimes, which are embedded in a macro level called "landscape". Based on this approach, authors have proposed policies and helped to define business strategies (Markard and Truffer, 2008).

Such an approach allows working with different levels of system stability. The socio-technical regime is characterized by a high degree of stability, whereby actors and institutions reproduce and maintain the existing system. Thus, it is apparent that innovations that arise at the regime level tend to have an incremental character, as the presence of lock in mechanisms and path dependence lead to changes along the established technological trajectory. It therefore at the niche level that the disruptive innovations tend to appear, as at this level practices and institutions are not yet stabilized. In short, niches are protected areas (market segments where demand has specific characteristics, demonstration projects, research and development laboratories, etc.) in which actors seek the development of promising innovations, which can be incorporated into the regime, or even replace the existing regime in the long run. Within a niche, processes of learning about a new technology take place, together with the alignment of expectations and building of a network. Such processes lead to the involvement of more actors, which enables the expansion of these niches. Finally, above regimes and niches, there is the socio-technical "landscape", comprising elements on which niche and regime actors have little influence and those that change only slowly, such as wars, economic crises, culture and demographical trends (Geels, 2005a).

The various dimensions interact in a dynamic where innovations arise in niches, while slow changes happen at the landscape level, both of which exerting pressure on the existing socio-technical regime. The destabilisation of the regime creates opportunities for the dissemination of innovations originated in niches. In this sense, the Multilevel Perspective considers that the transition process is not the result of linear and unidirectional causal relationships. According to this approach, there are interrelated processes cutting across different levels and comprising multiple (social, economic, political, technical, etc.) dimensions that build up and influence one another; it is therefore possible to speak of "circular causality" in the transition process.

The MLP has been applied the analysis of transition processes taking place at the energy sector,considering the importance of lock-in effect on this industry and pressure from other socio-economic developments. For example, Solomon and Krishna (2011) emphasize the importance of this methodology to examine energy transition processes in general, while Strunz (2014) uses it to analyse the German energy transition, and Mah et al. (2012) address the development of smart grid in South Korea.

4 – SMART GRIDS IN BRAZIL

The analysis of the status quo and perspectives of development of smart grids in Brazil requires prior knowledge of the motivations and challenges involved. This analysis should include not only issues related to the energy sector, but also consider Brazilian socio-economic variables. For example, one must consider the reduced Brazilian per-capita income because it makes implementation costs one of the most relevant obstacle when compared to the reality of developed countries, because costs can hardly be passed on to consumers. The purpose of this section is to analyse the development of smart grids in Brazil with the aid of the multi-level perspective.

4.1 – Landscape

Even considering the increase in income per capita projected over the next twenty years, Brazil will be no more than a country whose income is at average levels internationally. Therefore, the decision of allocation of scarce resources becomes even more complex due to the need to meet several competing demands. This results in difficulties in the definition of priority capital expenditures by the public and private sectors. In contrast, the ability of consumers to pay for the provision of public services is limited, which justifies, for example, the search for low tariffs as one of the priority guidelines in the Brazilian power sector. In addition, the low level of income of a considerable part of the population leads to high levels of non-technical energy losses, especially in regions where the enforcement and inspection is weak and, thus, illegal connections are made (stealing electricity).

In terms of the structure of the economy, although the tertiary sector is predominant in the Brazilian economy and the agricultural sector is also significant, there are many industries characterized by a high energy consumption. As a result, the energy intensity of the Brazilian economy is not low and ensuring energy supply at reasonable prices is of relevance to the competitiveness of domestic industry.

In recent years, there has been much discussion of the process of "earlier deindustrialization" of the Brazilian economy (Carvalho and Kupfer, 2011; da Silva, 2014). This process is characterized by a reduction in the share of the industrial sector in the Brazilian economy, at an early stage of socioeconomic development, characterized by a relatively low level of per-capita income. Given that the Brazilian industry tax costs are often mentioned as one of the main reasons for this phenomenon, it is understandable that the prices of electricity are seen as an added obstacle for the industry.

At the same time, Brazil needs to increase the added value of the national economy through the development of sectors more intensive in technology and knowledge. This strategy aims to make Brazil a developer of technologies in different areas rather than its traditional role of importer of technologies and, consequently, generate income, jobs and foreign exchange. As illustration, the Greater Brazil Plan established, among its goals, an increase in expenditure on research and development as a proportion of GDP, a higher percentage of knowledge-intensive industry, and qualification of human resources.

In this context, we emphasize the importance of developing smart grids, as an economic structure with higher technological density will allow the existence of an electricity network with real-time monitoring of energy flows. In addition, if stimulus are given to the local development of the equipment industry, investments in smart grids may become a value-added mechanism for transforming the Brazilian economy.

The corollary of the maintenance of the Brazilian industrialization process, as well as development focused on sectors with higher added value and more efficient use of energy resources is a reduction in energy intensity of the Brazilian economy. However, considering the still low per-capita level of power consumption in the Brazil, in absolute terms the consumption tends to grow over the coming decades. In particular, demand for electricity should show significant increases.

Besides the demand for electricity is increasing, the requirements of consumers in terms of quality and sustainability of goods and services is also increasing. This consumer behaviour change is associated with diffusion of the knowledge society and a more effective participation in the economy. As a result, the power sector will be subject to increasing pressures on the reliability and quality of supply.

Given the higher demand of society for the sustainability of socioeconomic activities, the need to preserve natural resources and the mitigation of environmental impacts will become increasingly imperative. In fact, since the 1988 Constitution there is a more rigid Brazilian environmental legislation, especially in terms of implementation of projects in the Amazon biome. In turn, in light of the level of climate change mitigation efforts comprised by the Paris Agreement, Brazil will assume formal commitments to reduce its emissions of greenhouse gases. As a result, it is expected that some emissions limitation effort will be imposed on the Brazilian energy sector.

In summary, we can say that the Brazilian landscape in which smart grids are circumscribed indicate potential efficiency gains, the promotion of a more reliable system and higher quality as key drivers in a context of significant growth in demand. The environmental driver is smaller when compared to dynamic seen in countries with electrical systems characterized by the predominance of generation from fossil sources. In the case of regions with high non-technical losses, addressing this issue is also an important motivation. Furthermore, one needs to consider adherence between the development of smart grids and the goal of providing the Brazilian economic structure of greater technological density. On the other hand, limitations on capital availability to the investments and the necessity of offer energy at affordable prices consist of barriers for smart grid development in Brazil.

4.2 – Socio-Technical Regime

In 2014, the Brazilian electricity consumption was approximately 531 TWh, being approximately 2630 kWh per capita. Therefore, it is a level of consumption still relatively modest compared to developed countries. This consumption has been met by a 624 TWh production and thus there was a loss in the order of 14,9% (MME e EPE, 2015a). Although Brazil is a country with an interconnected system of intercontinental dimensions, these losses are not explained only at the technical level because also include non-technical losses (theft) of energy.

At the level of electricity generation, Brazil's system is predominantly hydroelectric. To handle the seasonality of inflows, the hydric park was built historically associated with storage reservoirs with the function to regularize the supply of energy throughout the whole year. In addition, it has a robust transmission system in order to interconnect different regions and to exploit synergies derived from the differences between these inflows regions. In turn, the function of the traditional thermal power stations must be backup system.

Is highlighted that, even with the water crisis that started in late 2012 and the consequent need to dispatch a large amount of thermal power plants on the system's basis continuously, the hydro park continues to account for over two thirds of electric power generation. However, the profile of the hydro park is changing and, to a large extent, the current water supply crisis is already consequence of this paradigm shift.

Given that the remaining hydropower potential is located in the Amazon region, which is characterized by soft topography, and there are restrictions imposed by the environmental sphere, the plants that are being built, as planned, do not have storage reservoirs. Therefore, the regulating capacity of the hydroelectric supply is clearly downwards and therefore the hydroelectric energy supply will become increasingly seasonal.

We observe thus the need to diversify the Brazilian energy matrix, especially when considering that the expected growth in demand for electricity between 2014 and 2024 is 260 TWh (MME e EPE, 2015b). Thus, prospects are of a considerable increase in non-hydro renewables in the period, which is consistent with the finding that the exploitation of Brazil's potential for renewable energy is a relevant and aligned strategy with the promotion of a low carbon economy. In this sense, besides the inclusion in the network of surplus electricity produced in sugarcane plants from the residual processing of sugar cane biomass, in recent years there has been significant investments in the construction of wind farms. As a result, the installed capacity of wind power generation amounted to approximately 8.5 GW at the end of 2015.

Although wind power is seasonally complementary to the hydrological regime, it is an intermittent source that poses challenges for system operation, especially in terms of peak demand service. Even if the participation of wind generation is still small, these effects can already be noticed. This difficulty tends to be accentuated with the inclusion of solar generation, specifically photovoltaic solar energy over the next few years. Given that the diffusion of photovoltaic generation will occur mainly in the consumer units connected to the low voltage network (according to Resolution 482/2012 and its later revisions), the issue of intermittency will also need to be managed directly by the electricity distribution companies.

In order to ensure security of supply, hiring controllable power plants presents itself as a relevant strategy. Generally speaking, the strategy consists in the realization of investments in thermoelectric plants to operate in the base of the system, as well as in thermoelectric plants equipped with dispatch to meet peak demand. At the same time, it recognizes the importance of carrying reinforcements on the network in order to make it more robust.

However, one must emphasize that the flexibility of demand can take on great importance in the system management. While the entire set of measures in the scope of demand side management is important in terms of an integrated view of energy planning, the focus here is specifically on demand response measures that alleviate the system’s peak demand. At the level of large consumers, there is the existence of rates of time-of-use type (TOU). This tariff structure shows a time signal that aims to distinguish the peak hours compared to other times. In fact, studies indicate that industrial consumers effectively respond to this tariff signalling.

More recently, the white tariff mode destined for low voltage consumers was created, whose membership are optional. This tariff structure is also the TOU kind and seeks to distinguish the price of energy in terms schedules on weekdays, i.e. the peak hours between 18 and 21 hours; an intermediate time comprising the hours immediately before and after the peak hours; off the peak comprising the remaining schedules. However, the effectiveness of the white tariff requires the existence of smart meters. But, currently, the vast majority of consumers continue to have their energy consumption measured by electromechanical meters. Although Resolution 502/2012 has set March 2014 as the deadline for the installation of smart meters in the consumer units who join the white tariff, this issue is not yet equated due to the limited supply of smart meters in the market and uncertainty about technical standards. In this context, it is understandable why in February 2014 ANEEL chose to postpone the schedule originally envisaged for implementation of the white rate.

The existence of intelligent tariff models is a central rationale for the dissemination of smart meters. But there are other reasons, which range from inciting more efficient behaviour in the use of equipment, to handling two-way flows of energy and monitoring the load. Furthermore, the need to combat non-technical losses in some regions emphasizes the importance of implementing smart meters. While these meters alone will not reduce losses, they permit to accurately identify loss location and therefore they make it possible to adopt effective measures for combatting fraud.

However, it should be stressed that the development of a smart metering system and not only the roll out of smart meters is required. This highlights the the importance of communications infrastructure. Given the precariousness of the Brazilian telecommunications network, it is common that distribution companies have to develop their own networks. As a result, the cost of smart metering systems ends up being a burden and this makes it difficult to implement them, with the potential impact on tariffs.

Consequently, given that smart grids are not limited to smart metering, we need to consider other of its aspects in terms of relevance to the Brazilian electrical system and the plausibility of effective implementation. Therefore, it is first necessary to consider the status quo of the current grid. In this regard, the generation facilities and transmission system operators in Brazil are characterized by the presence of automated systems equipped with digital technology and controlled by virtual centers. Thus, it is possible to monitor in real time the operating conditions. In contrast to the high voltage domain, distribution companies have networks characterized by an automation level still quite limited. The operation of the distribution network continues to be performed based on conventional technologies and practices (Galo *et al.*, 2014).

Furthermore it is important to emphasize that the Brazilian distribution network has obsolete assets. Therefore, it becomes understandable why, in addition to the high level of losses, there is a low quality of electricity supply. This poor quality is measured by the high number of interruptions during the year and the duration of these interruptions, the latter metric directly derived from difficulties / system limitations in correcting faults and carrying out the re-establishment (Di Santo et al., 2015).

The modernization of the distribution infrastructure, particularly the development of smart grids is central to the improvement of quality of service, contributing to the achievement of objectives such as increasing system efficiency level and reducing of non-technical losses. However, they are not checked effective efforts in this direction. To a large extent, the difficulty arises from the current regulatory model because it does not encourage companies to opt for more efficient technology: it does not recognize the investment and/or the investment cannot be paid appropriately with the current rules, especially when they concern technology characterized by a cost structure of higher OPEX relative to CAPEX. The issue of investment in telecommunications networks and information technology has thus become problematic.

4.3 – Niche-innovations

With the aim of developing smart grids in Brazil, there is some important niche initiatives. The legislative framework is being reformed: bills are still pending in Congress, such as 608/2001, 84/2012 and 3337/2012 which deal with the large-scale dissemination of smart grids. In parallel, there is the work of the inter-ministerial group under the command of ABDI (a quasi-governmental organization devoted to industrial development) that seeks to identify the entire production chain of smart grids and propose public policies that include the development of a national industry. In the context of regulatory guidelines, besides the already mentioned Resolution 482/2012 and 502/2012, there are resolutions 375/2009 and 395/2009 which deal respectively with the use of the distribution network to carry analog and digital signals (for example, internet) and the implementation of georeferenced information of the distribution network system.

However, it must be emphasized that the most effective initiatives for smart grid development are still restricted to research and development projects, in particular through pilot projects implemented by some electricity distribution companies. Commonly, these projects are intended to test on a sample of market technologies and measures inherent to smart grids, among which, metering systems and smart tariffs, network automation (including self-healing), micro, electric mobility and smart home.

As an illustration, there is the InovCity project developed by EDP / Bandeirantes in the city of Aparecida (state of São Paulo), which is analogous to the project implemented by EDP in the city of Évora in Portugal. The city of Aparecida represents 1% of the consumer market of EDP / Bandeirantes and the project covers a universe of 15,000 consumers. The project includes the installation of smart meters, energy efficiency measures, network automation, distributed generation, public lighting provided with efficiency, public awareness actions on the rational use of energy and electric mobility.

In turn, AES / Eletropaulo has the largest smart grid project in Brazil in the cities of Barueri and Vargem Grande Paulista (both in São Paulo). Given that Barueri is part of the metropolitan region of São Paulo, this is a suitable city for experiments to be replicated in urban and industrial areas. In short, the project will meet 52,000 consumers in Barueri and will include smart metering and automation of the network in order to reduce commercial losses, improve quality of supply and make the system more efficient. In contrast, Vargem Grande Paulista is an essentially rural area where the concessionaire seeks to develop solutions for such regions, especially in terms of self healing.

With some variations, similar projects to the EDP / Bandeirantes and AES / Eletropaulo are being developed by Ampla in the city Buzios (state of Rio de Janeiro), by Cemig in the city of Sete Lagoas (Minas Gerais) and by COPEL in the metropolitan region of Curitiba (paraná). Generally speaking, the projects seek to not only find ways to make the system more efficient and with lower operating costs, as define a model to be replicated on a larger scale.

The development of smart grids is occurring primarily on the basis of pilot projects, because the current regulatory framework does not encourage the modernization of the network, there are specific niches where the reduction of operating costs can justify larger investments. This is the case of Light in Rio de Janeiro that has already installed 400,000 smart meters in order to reduce commercial losses and, consequently, improve its operating result.

5 – CONCLUSIONS

Growing demand for electricity and the predominance of renewables in the energy matrix make smart grids motivations in Brazil a little different from those observed in developed countries. Although the easing of demand has increasing importance due to the disseminating intermittent sources, investments in smart grids are justified primarily by the need to improve the poor quality of supply, make the system more efficient and enable the reduction of non-technical losses.

But, it is noteworthy that the current regulatory framework does not encourage investment in network modernization. Thus, existing smart metering projects turn out to be too restricted to research and development projects, particularly pilot projects. Therefore, it emphasizes the necessity of regulatory changes that encourage innovation and regulation of new business. In addition, the formation of public policies providing, for example, targets for rolling out smart meters, or standard quality requirements of the telecommunications infrastructure.

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Tracking fuel poverty with smart meters: the case of Évora

João Pedro Gouveia (jplg@fct.unl.pt), Júlia Seixas (mjs@fct.unl.pt)

CENSE – Center for Environmental and Sustainability Research, Department of Science and Environmental Engineering, Faculty of Science and Technology, Universidade NOVA de Lisboa, Portugal.

ABSTRACT

Fuel poverty is a recognized as an increasing problem in several EU countries. A growing body of literature covers this topic in several European countries, but despite being very vulnerable to this condition, hitherto no dedicated analysis of Portugal has been done. We combine electricity smart meters' registries (average 2011-2014 of 265 meters) with socio economic data collected from door-to-door surveys for the same houses to track fuel poverty, using the Portuguese city of Évora as case study. We apply a hierarchical cluster method and survey screening to elaborate on consumers' segmentation. Our results unfold that one of the ten electricity consumption clusters is characterized as under fuel poverty (21% of the sample) due to the lowest electricity consumption levels. The socio economic data from the survey support a fuel poverty profile: low incomes, occupants older than 65 years, houses built 1946 and 1990 with no insulation, low levels of ownership and use of fireplaces and heating equipment on gas. These data combined with the annual consumption profile portray the lack of fulfillment of thermal comfort levels inside households both in summer and winter.

KEYWORDS: Fuel Poverty, Smart Meters, Surveys, Hierarchical Clustering, Évora

1 INTRODUCTION

Fuel poverty is increasingly becoming a problem in European countries as acknowledge by the European Council Directive 2009/72/EC. Atanasiu *et al.* (2014) estimates that between 50 and 125 million people are currently unable to afford proper indoor thermal comfort. Nevertheless, despite the pan-European dimension of the problem, no consistent and common definition of fuel poverty is used in Europe Union (EU) countries.

For the purpose of this paper, following the Republic of Ireland and United Kingdom (UK) definition, fuel poverty occurs when households are unable to afford adequate energy services in the home at reasonable cost, while spending more than 10% of its disposable income on energy services (Department of Communications, Energy and Natural Resources, 2011; Department of Energy and Climate Change, 2013). It includes all uses of energy and considers the thermal comfort levels needed and not what is effectively being consumed.

For this matter, the combination of low incomes (Wright, 2004; Saunders *et al*., 2012; Moore, 2012); low performance dwellings with defective insulation (i.e. windows, walls, roofs) (Shortt and Rugkasa, 2007, Morrison and Shortt, 2008), older household members (EPEE, 2009) and high costs of energy (Atanasiu *et al.*, 2014) are enablers of fuel poverty.

Proxy indicators have been used to estimate fuel poverty, such as the ones included in the EU Statistics on Income and Living Conditions (EU - SILC) like: inability to keep home adequately warm; arrears on utility bills; and the presence of a leaking roof, damp walls, floors or foundation, or rot in window frames or floor (Thomson and Snell, 2013). For Thomson and Snell (2014) the surveys behind those indicators were not designed to measure fuel poverty and as such provide imperfect estimates of the problem.

As recognized by Thomson and Snell (2013), knowledge on fuel poverty in UK and Ireland is well established, with a strong focus on heating demand (Healy and Clinch, 2002a). A lot of work as also been also carried out focusing on the impacts of fuel poverty on health (Healy, 2003; Marmot Review Team, 2011) since the impact of temperature and damp upon the body are significant (Sumby *et al.*, 2009).

Therefore, despite a growing body of literature covering several European countries (e.g. Brunner et al., 2012; Atanasiu *et al.,* 2014; Pye *et al*., 2015; Schumacher *et al.,* 2015) and acknowledged by Thomson and Snell (2013) and Wand (2013) as being a particular problem for southern European member states, single evaluation of such countries have recurrently dismissed Portugal.

Despite being a warm southern EU country with mild winters, several facts point Portugal as severely endangered by fuel poverty issues. Healy and Clinch (2002b) sets Portugal within the group of EU countries with the poorest housing status (as Greece, Ireland and UK) with consequences in the levels of excess winter deaths. Between 2007-2012 Portugal has ranked first or second in this EU28 ranking.

Portugal had in 2014, 27.5% of people at risk of poverty; 20.9% of people with arrears on utility bills, 28.3% of people enabled to keep home adequately warm, 35.7% living in a dwelling not comfortably cool during summer time (2012 data) and 32.8% of dwellings with leakages and damp walls (Eurostat, 2015). A combination of these indicators sets the scene to identify the share of people at risk of poverty who are affected by fuel poverty. According to Bouzarovski, S. (2013) calculations, Portugal ranks in the top three EU countries of fuel poverty risk, mainly justified by the lack of thermal comfort levels inside households.

Additionally, the electricity and natural gas prices for families with all taxes included were, in 2014, 12% and 32%, respectively, higher compared to EU28 average (DGEG, 2015). All these indicators have continuously been increasing in recent years stressing the need for in depth and dedicated studies on fuel poverty for Portugal.

This paper contributes to fill this gap using a different perspective and datasets, deriving fuel poverty from electricity consumption. We combine electricity smart meters' registries (average 2011-2014 of 265 meters) with socio economic data collected from door-to-door surveys for the same houses to track fuel poverty, using the Portuguese city of Évora as case study. The paper is organized in four sections. Section 2 describes the methodology used, while Section 3 is dedicated to the case study results on fuel poverty. Section 4 concludes.

2 METHODOLOGY

The abovementioned literature review shows the lack of studies at both national and international grounds addressing fuel poverty issues in Portugal interlinked with the high percentage of people in risk of fuel poverty in the country. These sets the background for our methodology, where we combine household surveys, daily electricity consumption data to evaluate fuel poverty at a city level. The specific goals of each approach are explain bellow (Figure 1).

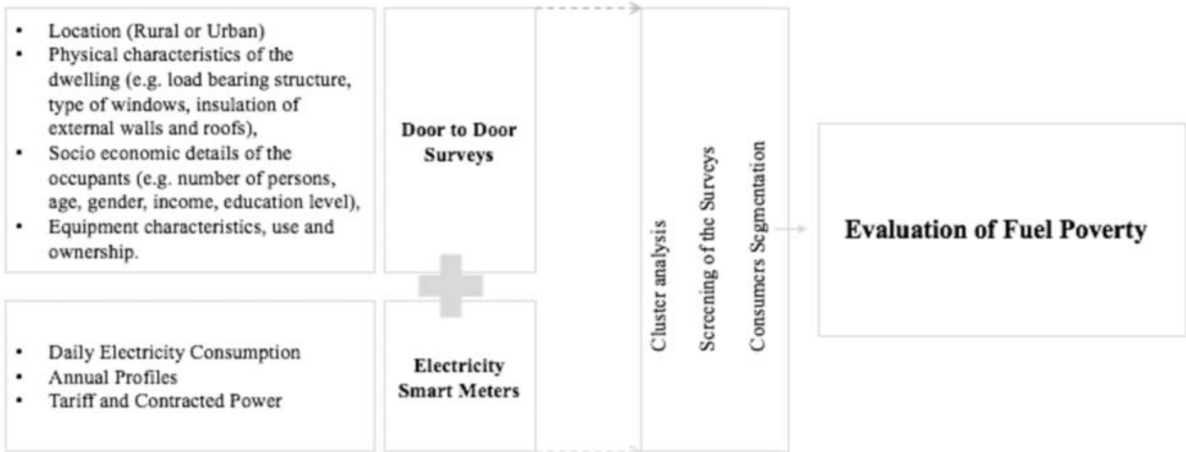

Figure 1 – Overall methodology to track fuel poverty

1.1 Door-to-Door Surveys

Surveys of households' energy use are increasingly common in many developed countries and are important sources for energy data (e.g. EIA, 2009; INE and ICESD, 2011). However, most of these studies and statistics are presented only at national or regional level with no city spatial detail, missing the opportunity to characterize the determinants of energy consumption and groups of consumers at city level.

Different from Thomson and Snell (2014) approach that proposed a pilot survey exclusively dedicated to evaluate fuel poverty; our objective with a door to door survey was to characterize the residential sector of the city of Évora within the EU INSMART project (Gouveia et al., 2015), and to identify distinct groups of electricity consumers. Nevertheless, several recommendations from Thomson and Snell (2014) to the EU SILC survey and for a future EU28 household survey on fuel poverty were accommodated in our survey. We included questions regarding the heating and air conditioning equipment, energy efficiency questions concerning forms of insulation and window glazing, the type of energy sources used for primary and secondary heating and socio economic details as income.

Thus, we conducted 389 door-to-door surveys with 110 questions covering information about location, physical characteristics of the dwelling (e.g. load bearing structure, type of windows, insulation of external walls and roofs), socio economic details of the occupants (e.g. number of persons, age, gender), appliances characteristics, use and ownership.

1.2 Electricity Smart Meters

The information from the buildings survey benefits from its combination with data from electricity smart meters, whenever these are available. In the city of Évora, the electricity distribution system operator is running a smart grid project - InovGrid with registries of 15-min interval electricity data (EDP Distribuição S.A., 2015).

Through the combination of this smart metering dataset as in Wyatt (2013) and Bartusch et al. (2012); and a door-to-door survey as in Kavousian et al. (2013) and Gram-Hanssen et al. (2004); we have made an in-depth analysis through segmentation of consumers based on clustering electricity consumption, aiming to identify distinct yearly electricity consumption profiles and to characterize their determinants trying to isolate important groups of consumers for policy and stakeholders.

For our objective, while avoiding too much granularity (by using 15-minute data), daily electricity consumption data was retrieved for the years 2011 to 2014 for a sample of 275 meters. Despite the information acquired from the surveys referred only to 2014; we assumed that the characteristics mostly apply for the electricity profiles of 2011-2014.

A data trimming of the electricity dataset was made. Following Torsten and Mathias (2013) meters with annual readings with less than 80% of available electricity readings were discarded. The 275 meters were therefore reduced to 265. For further analysis, the daily electricity consumption data were averaged for the four years, preserving the intra-annual variability for each household. This approach will allow us to identify important and distinctive profiles of consumption and make typifications of consumers' characteristics (e.g. dwelling characteristics and occupants' profiles). The 265 meters remained with few days with missing data (less than 1%), for which we imputed values based on the average values of the neighboring days.

1.3 Consumers Segmentation and Characterization

An exploratory data analysis of the final sample of 265 households' daily electricity consumption data sets from smart meters was made, as well as a clustering analysis. The cluster analysis was carried over the daily means (per household), i.e., averaged over 2011-2014 for each day. After the previous explained electricity data trimming, we applied a hierarchical clustering using the Ward's Method (Ward, 1963) with a measured interval through the squared Euclidean distance, allowing an analysis of variance approach to evaluate the distances between clusters. This method is regarded as very efficient, however it tends to create clusters of small size (Statsoft, 2015). Therefore, through an iterative process, we evaluated the clustering results for a number of clusters ranging from 3 to 12. We concluded that still maintaining robustness and statistical significance of the clustering, only increasing the number of clusters allows to capture distinct yearly consumption patterns and to create types of consumer for which different policy and energy reduction measures could be targeted. The 10 clusters option with similar means and standard deviations were selected for further profiles analysis and consumers' identification.

A screening of the surveys allocated to each cluster was made in order to recognize the parameters (e.g. dwelling characteristics, occupants' profiles, electrical appliances ownership and use) that further explain the electricity consumption patterns and major similarities/distinctions within clusters allowing an increased knowledge on the clusters segmentation and type of households within each cluster.

From the information collected in the households' survey, we retain the following variables to characterize the households in each cluster: (i) location (Urban and Rural), (ii) dwelling type, (iii) dwelling age, (iv) dwelling total floor area, (v) type of glazing and windows framing, (vi) bearing structure and (vii) type of external walls. The socio economic variables, which might influence electricity consumption, were selected: (i) the number of occupants (ii) education of the household responsible person (iii) household income and (iv) employment status. Factors associated with electrical appliances and heating and cooling equipment were also selected: (i) ownership of heating and cooling, (ii) ownership of white electrical appliances, (iii) type of tariff and (iv) contracted power.

3 RESULTS AND DISCUSSION

In this section, we explore the results from the clustering analysis and household surveys allowing to identify and characterize group of consumers to target specific energy efficiency or/and energy reduction measures.

The residential buildings survey and electricity data analysis had as primary objectives twofold: 1) combine groups of consumers based on their electricity consumption annual profiles and 2) highlight main socio economic differences and similarities amongst households in each of the clusters. Derived from this first assessment and results we were able to look deeper into fuel poverty issues.

The clustering method applied split the 265 electricity smart meters' dataset into 10 clusters, showing a distinct distribution of meters (with at least 25 meters per cluster) within clusters with mean daily electricity consumptions below 12 kWh (cluster 1 to 5), totaling 217 meters (more than 82%) and the other five clusters. The remaining 47 meters are included in clusters 6 to 10 fitting the high levels of consumption and/or variability with daily median consumption of almost 28 kWh (i.e. cluster 8). The box-and-whisker plot (Figure 2) unveils the descriptive statistics of the clusters (C*i*) regarding their dispersion and skewness, and the existing outliers. The distribution of electricity consumption data from C1 to C5 is similar, with C1 presenting the lowest statistics (median 3.99 kWh and standard deviation of 2.10 kWh) and C2 the highest variance (standard deviation of 4.26 kWh). The short box plots within these clusters (and also C9 and C10 at a certain extent) suggests that, generally, the consumption data have similar profiles. Clusters C6 to C8 present tall box plots depicting significant variances (standard deviations ranging from 6 to 11 kWh) within clusters already unveiling possible differences among the seasons of the year. Cluster C7 shows the highest data variability (standard deviation of 10.87 kWh) and highest consumption. With the exception of clusters C6 and C7, all the other clusters have a consistent distribution of data within the second and third-quartile. Based on these profiles analyses we identified cluster C1 as a possible segment of our sample which might be under fuel poverty conditions.

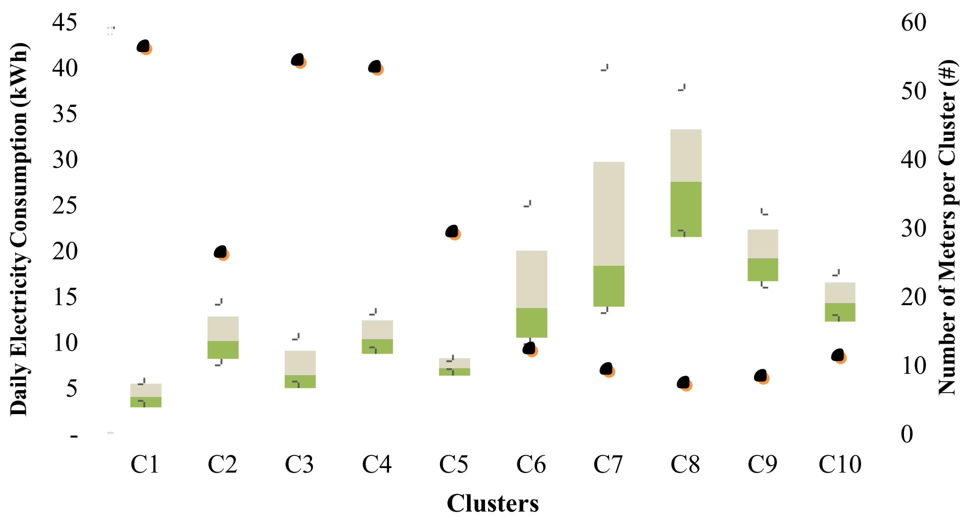

Figure 2- Daily electricity consumption (box and whisker plot) and number of meters (black circles) per cluster

Cluster C1 presents a higher difference on winter and the remaining seasons (Figure 3) portraying the inexistence or low use of cooling equipment in the summer compared to a higher use of electricity-based technologies for space heating in the colder months of winter (December, January and February) which is corroborated by the findings in Tables 1 to 4. For a thorough characterization of the electricity consumption of the households behind this cluster, we crossed the meters' data with the correspondent households' survey results.

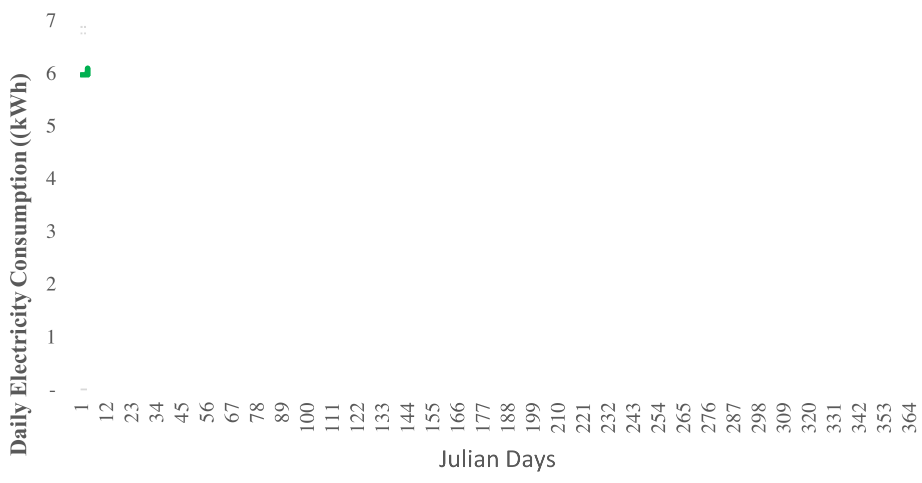

Figure 3 – Cluster 1 annual profile of electricity consumption (2011-2014 average)

Table 1 – Characteristics of the dwellings on Cluster 1

Characteristics of Dwellings																						
Location (%)		Type (%)			Period of Construction (%)					Average Household Area (m^2)	Bearing Structure (%)			External Wall (%)				Glazing (%)		Window Framing (%)		
Urban	Rural	Semi Detached	Terraced	Detached	<1919	1920-1945	1946-1990	1991-2005	≥2006		Concrete	Masonry Wall with and without plate	Masonry wall with loose stone	Brickwork double layer with insulation	Brickwork double layer without insulation	Brickwork single layer	Stone Masonry and Rammed Earth	Single	Double	Aluminum	Wood	PVC
61	39	30	52	18	16	20	55	9	-	90	24	70	6	6	2	72	20	83	17	38	60	2

Table 2 – Characteristics of household occupants of Cluster 1

Characteristics of Household Occupants																						
Average Number of persons per household	Age of Household Members (%)					Gender of Household Members (%)		Education of the Head of the Family (%)			Monthly Average Income of the Household (%)				Employment Status (%)				Household Occupation Contract (%)			Relation of Household members (%)
	<5 years old	5-17	18-49	50-64	≥65 years old	Male	Female	<9th grade	9th-12th grade	Graduation, MSc or	≤750€	751€-1500€	1501€-2500€	≥2501€	Working	Retired	Student	Other	Owner	Rented	Tenant for Free	Family	Room Mates	Other Couple
2	-	7	32	18	43	44	56	53	35	12	60	29	11	-	32	47	15	6	60	38	2	89	9	2

Table 3 – Appliances ownership in households of Cluster 1

Appliances Ownership																								
Heating Technologies (%)			Cooling Technologies (%)			DHW Technologies (%)		Cooking Technologies (%)		White Appliances and Other Electric Equipment (%)									Lighting (%)					
Heating Equipment Ownership	Electric (HVAC, heaters)	Non Electric (fireplaces, gas room heaters, heat pumps)	Cooling equipment Ownership	HVAC	Fan	Electric (electric resistance)	Non Electric (gas, solar)	Gas Stove	Electric Stove	Desktops	Laptops	Refrigerators	Freezers	Microwaves	CWM	CDM	DWM	TV	IL	TFL	CFL	HL	LED	Lamps per household
86	88	12	46	27	73	6	94	98	5	16	52	100	61	91	96	16	29	171	20	3	72	3	2	10.1

Note: PVC - poly(vinyl chloride), HVAC - heating, ventilation, and air conditioning; DHW - domestic hot water; CWM - cloth washing machines; CDM - cloth drying machines; DWM - dish washer machines; IL - incandescent lamps; TFL - tubular fluorescent lamps; CFL - compact fluorescent lamps; HL - halogen lamps; LED - light emitting diode

Table 4- Contracted power characteristics of the households in Cluster 1

Contracted Power Characteristics				
Contracted Power (%)			Type of Tariff (%)	
≤3.45kVA	*4.6-6.9kVA*	*≥6.9kVA*	*Single*	*Dual*
78	20	2	71	29

Cluster 1 is characterized by a predominance of terraced dwellings located in urban areas, in small houses (around 90m^2) built between 1946 and 1990 period. Following the period of construction, materials and techniques, the predominant bearing structure of the dwellings comprised in this cluster is masonry wall with or without plate associated with brickwork single layered in the external walls. The majority of the dwellings (83%) have single glazing and wooden window framing.

Regarding occupants' characteristics, we can say that these clusters' households are portrayed by the smallest families of all clusters (average of two persons per household), generally older than 65 years old with low levels of education (secondary level), retired and with households' monthly average income below 750€. It is in this cluster that the level of owner occupied houses is the lowest, with a relative important share of rented houses (38%).

The electricity profile of this cluster defined by a significant difference of consumption on winter months is backed up by the survey results with predominant ownership and use of electric heating equipment (88%). Only 46% of these cluster dwellings have cooling equipment. From which, near 80% own fan coils, that consume a lot less than HVAC systems. Still, it is in this cluster that the ownership and use of fans is the lowest.

In C1, the overall smallest ownership of white appliances, computer equipment and lamps from all the clusters combined with the dominant number of houses (78%) with low contracted power (under 3.45kVA) also explain the lowest levels of daily electricity consumption in this cluster when compared to others. 71% of the houses in this cluster still have single tariffs not taking advantage of the lowest prices at night of dual tariffs.

Being the cluster with the higher number of dwellings from our sample (21%), C1 is, as seen, characterized by the lowest electricity consumption levels and annual consumption profile portraying the lack of fulfillment of thermal comfort levels inside households both in summer and winter, suggesting a case of fuel poverty.

The socio economic details, building characteristics and equipment ownership and use behind the households in this cluster are consistent wit the literature review characterizing enablers of fuel poverty. Also consistent with our findings, under EU fuel poverty network, it is pointed out that currently in Portugal, around 28% of the population under fuel poverty risk.

We conclude that fuel poverty is prevalent amongst the households in this cluster although an in-depth assessment of individual households suggests that not all households might experience fuel poverty in equal measure.

From our analysis we point out that fuel poverty issues related to cooling demand are also of paramount importance that should be further investigated, mainly on countries expected to suffer from average temperature increase due to climate change, as southwestern European countries.

The lack of awareness given to this topic from public institutions together with the country current situation derived from the proxy indicators of European statistics and our results for one city calls for further investigation, dedicated surveys and policy portfolio testing. Fuel poverty can be tackled by income increase, fuel prices regulation and energy efficiency improvements in buildings. In Portugal, energy subsidies (named as social tariff) have been provided for the poorest households, but as discussed by Atanasiu et al. (2014), these subsidies do not provide a sustainable long-term solution to the fuel poverty problem. On the opposite, energy renovation measures of households in fuel poverty risk can give a long-term sustainable answer to fuel poverty. These measures address the root of the problem and result in reduced energy costs and/or improved thermal comfort in homes.

4 CONCLUSIONS

This paper shed the light on how to track fuel poverty using a combination of electricity smart meters' dataset and door to door surveys with information of socio economic household occupants' details, building structure characteristics and equipment use.

The presented approach is anchored on the use of daily electricity consumption data evaluated by a cluster analysis, proving to be a powerful data nutshell to distinguish groups of consumers while giving insights of distinct groups of consumers (e.g. under fuel poverty and also with fuel "obesity" levels).

The characterization of the dwellings, in terms of construction type, socio economic factors and equipment, beneath the consumption of the clusters highlight and explain the wide range of electricity consumption groups of consumers, within the same country region. This illustrates the relevance of consumer segmentation to derive important or fragile consumer groups for policies and measures design and implementation, tailored to energy reduction, increase of indoor thermal comfort levels, energy efficiency increase and renewable energy integration.

Despite mainly focusing on electricity consumption, this results provides policy makers and relevant stakeholders such as ESCOS and energy utilities and the general population to recognize the problem, include it in current policies whilst also providing a comprehensive picture of its evolution over time.

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Economic benefits of small PV “prosumers” in south European countries

Cristina Camus[1]

[1] *ISEL – Polytechnic Institute of Lisbon, Conselheiro Emidio Navarro,1, Lisbon, Portugal, ccamus@deea.isel.ipl.pt*

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ABSTRACT

Within various renewable energy technologies, Photovoltaic (PV), long known as one of the most expensive, is today becoming cost competitive with wind, hydro and other conventional thermal technologies in countries with a considerable number of hours of sun exposition. The development of the PV sector in the last decade has been fuelled by the implementation of various supporting strategies aimed to reduce the gap between PV energy cost and the price of energy from conventional generation. Many countries have had policies which directly subsidise small-scale PV systems for domestic applications but these have stopped in 2014/15 not only as a response to economic crisis but mainly because solar PV has become able to compete without subsidies.

This paper presents a comparative assessment of the expected economic benefits of grid-connected residential and small business PV systems. Case studies from Portugal, Spain, Italy, France and Greece are taken as examples, as they have similar levels of the solar resource and customers demand but some differences in electricity prices and financial support mechanisms.

The levelized costs of energy (LCOE) from PV systems have already, crossed the increasing cost of electricity for low voltage consumers. Italy, Spain and Portugal have higher electricity prices than France and Greece and for those, self-consumption and net-metering have become the most profitable solution even considering that the energy injected into the grid is paid at less than the average spot-electricity price (or even zero as the case of Spain). Under these conditions, a 50% to 80% of self-consumption is needed to attain any benefit from a PV investment, depending on, other also important factors, such as location and PV systems costs. The best case studies maximized NPV for 95% of self-consumption, which indicated for residential customers a low PV power installed and only 30% of self-sufficiency while for commercial consumers, as the majority of consumption coincides with PV generation, it is possible to install more PV power and attain almost 50% of self-sufficiency. With further increase of retail electricity prices and decrease of PV costs, PV self-consumption becomes the logical way to decrease energy costs with environment benefits (renewable energy) and increase energy efficiency (energy is generated locally).

KEYWORDS: Photovoltaic System, *prosumer*, Grid connected PV, LCOE

1. INTRODUCTION

Solar photovoltaic (PV) technology, which converts sunlight directly into electricity, is one of the fastest growing Renewable Energy Technologies in the world (IEA, 2014). PV, a clean, sustainable, renewable energy conversion technology is thus becoming a visible source in helping to meet the world's growing electricity demand. It draws upon the planet's most abundant and widely distributed renewable energy resource - the sun. The technology is inherently elegant - the direct conversion of sunlight to electricity without any moving parts or environmental emissions during operation. In the last ten years, cumulative installed capacity has grown at an average rate of 49% per year, and can, at present, be considered as a mature technology which in about two or three decades would probably move to the terawatt scale, of global cumulative installed power (Martínez-Duart JM, 2013, Hernández-Moro J., 2015). In Europe, from 2000 to 2013, solar PV deployment has increased at an annual average rate of 31% (40% between 2010 and 2012) and passed the 80GW in 2013 (Fig.1).

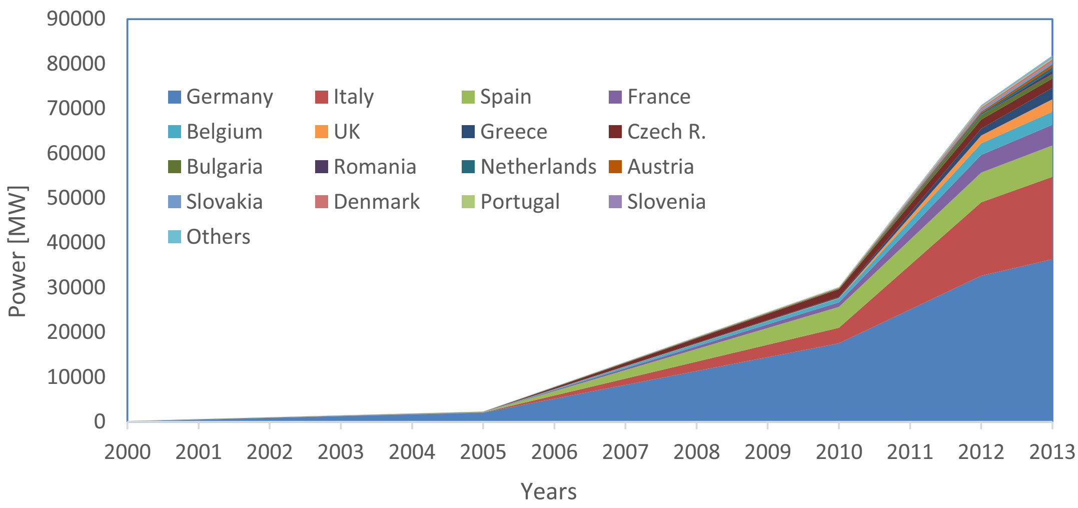

Fig. 1 – Evolution of solar capacity installed in Europe (EU energy, 2015)

Although Germany was the country with more capacity installed by the end of 2013, with almost 50% of all European capacity, Italy was the country with the highest percentage (7.4%) of PV generation within the country's total electricity production (Fig. 2).

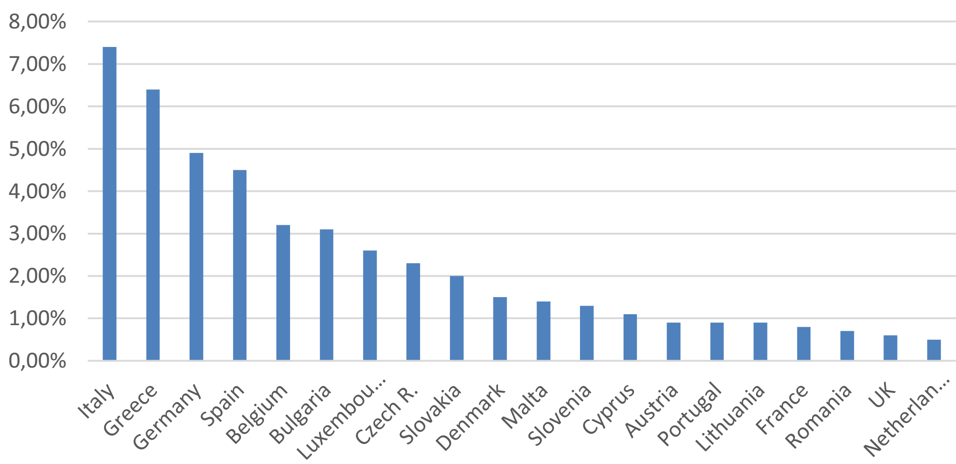

Fig. 2 – Percentage of PV generation within total electricity production in 2013 (EU energy, 2015)

In fact PV penetration at the end of 2013 was below 5% in all the European countries except in Italy and Greece (countries with both high sun exposition and considerable amount of PV capacity installed.

From 2004 to 2008, the price of PV modules remained approximately flat at €3.20 - €3.70/W, despite manufacturers making continuous improvements in technology and scale to reduce their costs. Much of this could be attributed to the fact that the German, and then the Portuguese and Spanish, tariff incentives allowed project developers to buy the technology at this price, coupled with a shortage of poly-silicon that constrained production and prevented effective pricing competition (Morgan Brazilian et al., 2013). From 2008 onwards PV systems prices have decreased (Fig. 3 – adapted from IEA-PVPS 2006 till IEA PVPS 2015).

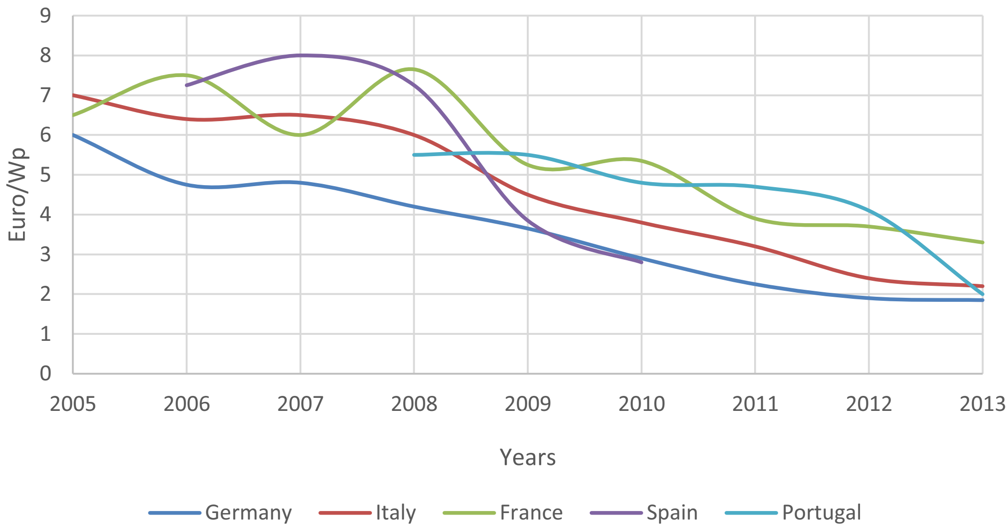

Fig. 3 – Evolution of PV systems prices in selected European countries

A growing important part of the PV market has been formed by Rooftop or Building Integrated PV (BIPV). This segment is important for deployment of PV because of two reasons: no additional space is required because the panels are mounted on existing or newly build structures and the energy is consumed locally reducing distributional losses and the need for network upgrades. The idea that PV producers could be considered as *prosumers* – both producers and consumers of energy – has been evolving rapidly and policies have been adapted accordingly in several countries. Net-metering policies have been considered in some countries such as, Denmark, Netherlands, Portugal, Sweden and Belgium and many countries are introducing a variant through self-consumption (IEA-PVPS 2015).

This paper presents a comparative assessment of the expected economic benefits of grid-connected residential and small business PV systems. Case studies from Portugal, Spain, Italy, France and Greece are taken as examples, as these counties have similar levels of the solar resource and customers demand but some differences in electricity prices and financial support mechanisms.

2. SUPPORTING STRATEGIES FOR PV SYSTEMS

The development of the PV sector in the last decade has been fuelled by the implementation of various supporting strategies, reducing the gap between the PV energy cost and the cost of energy for conventional generation. Different forms of financing have been put into force for PV systems in the last decade: capital subsidies, VAT reduction, tax credits, net-metering, feed-in tariffs (FiTs), etc.

2.1. PV supporting policies

PV is by nature a technology with limited maintenance costs, no fuel costs but a high upfront investment need in the earlier years. This has led some countries to put in place policies that reduce that up-front investment in order to incentivize PV. Capital subsidies, VAT reductions and tax credits are part of the government expenditures and are limited by their capacity to free enough money.

FiTs have been the most widespread support mechanism adopted all over the world. A FiT's value represents the full price received by an independent producer for any kWh of electric energy produced and injected into the grid by a RES-based system under a long-term contract between RES producers and the electric utility company, based on the generation cost of each technology. Under a FiT, utilities are obliged to purchase the energy produced from RES, paying a tariff established by public authorities and guaranteed for a fixed period. The FiT rate is determined by each country based on investment and maintenance costs. FiT is a very simple instrument to develop PV technology, but it needs to be fine-tuned on a regular basis in order to avoid uncontrolled market development. The subsidy component costs of FITs are normally spread among tax payers and/or electricity users; economic efficiency is thus central to their design (IEA-PVPS 2013).

2.2. Electricity Compensation Schemes

Various schemes exist that allow compensating electricity consumption and the PV electricity production, some compensate real energy flows, while others are compensating financial flows.

Traditional self-consumption systems assume that the electricity produced by a PV system should be consumed immediately or within a 15 minutes timeframe in order to be compensated. The PV electricity not self-consumed is injected into the grid. Several ways to value this excess electricity exist today (IEA PVPS 2015):

- The lowest remuneration is 0: excess PV electricity is not paid while injected;
- Excess electricity gets the electricity market price, with or without a bonus (Germany);
- A FiT remunerates the excess electricity (Germany, Italy) at a pre-defined price. Depending on the country, this tariff can be lower or higher than the retail price of electricity.
- Price of retail electricity (net-metering), sometimes with additional incentives or additional taxes (Belgium, USA).

A net-metering system allows energy compensation to occur during a longer period of time, ranging from one month to several years, sometimes with the ability to transfer the surplus of consumption or production to the next month(s).

2.3. PV markets evolution

The incentives towards micro-generation started strongly in 2008/9. Table 1 shows details of the initial purchased conditions for PV electricity in some European countries (L.M. Ayompe n, A.Duffy, 2013). Thanks to the declining cost of PV technology, several countries are starting to put in place rules allowing local consumption of the RES electricity produced. In 2014, the cost of producing electricity from PV (LCOE) continued to drop to levels that are, in some countries, below the retail price of electricity.

Table 1 – Micro-generation FiTs in years 2008/09 in some south European countries

Country	Guarantee period years	Year of implement.	PV Capacity kWp	Feed In Tariffs cents/kWh		
				Rooftop	Ground-based	Build integrated
Italy	20	2008	1-3/3-20	44/42	40/38	49/46
Spain	25	2009	≤ 10	34	32	
Greece	10	2008	<100	45.3		
Portugal	15	2008	≤ 3.7	65		

The Spanish government has suspended all incentives for PV systems in response to the current financial situation, PV generators up to 10kW have to pay for the net assess and receive nothing for the exported electricity (RD 900/2015).
In Portugal, in the end of 2014 a new legal framework was set to incentivize self-consumption and the electricity exported to the grid should be paid to the PV generator at a 90% of the monthly average Iberian Electricity Market (IEM) price and no net assess fees are charged until 3% of total power is achieved (DL 153/2014). In Italy and in Greece installations bellow 20kW pay no charges and receive the pool price for the exported electricity (Hellenic Association of Photovoltaic Companies, 2015). In France, in the end of 2014, the PV roof top tariffs were 0.0736 €/kWh for installations less than 12 MW (EPEXSPOT).

3. METHODOLOGY

In this section, self-consumption and related economic metrics are formally defined as well as input data and PV system modelling.

3.1.PV energy generation modelling and simulation

The amount of energy produced by the PV modules is determined by developing a mathematical model of the PV array allowing the determination of the extracted electrical energy as a function of the solar radiation and the ambient air temperature.
PV modules are commonly characterized by their *Wp* (Watt-peak) equivalent, being a measure of the nominal power of the PV module by determining the current and voltage while varying the resistance under defined laboratory illumination, at 1 kW/m² and 25°C. This peak power value serves a reference and is given per m² area of the PV module. A PV module characteristics is made under STC, the standard temperature and radiation conditions (radiation of 1000 W/m^2, and cell temperature of 25^{o}C). Short circuit current, I^r_{sc}, maximum power current I^r_{mp}, open circuit voltage V^r_{oc} and maximum power voltage V^r_{mp} are standard values available in manufacturer's catalogues.
The annual total of global irradiation, *G*, that hits the module, is specific for each location.
The model starts to compute the constant parameters:

Thermal voltage, V_T under STC

$$V_T = \frac{KT}{q} \qquad (V) \tag{1}$$

Where K is the Boltzman's constant (1.38 x 10^{-23} J/K), T, the cell absolute temperature in Kelvin (0 ºC = 273.16 K) and q, the electron charge (1.6 x 10^{-19} C).
The cell's ideality factor, m (ideal cell m=1, real cell m>1)

$$m = \frac{V_{mp}^r - V_{oc}^r}{V_T^r \, ln\left(1 - \frac{I_{mp}^r}{I_{sc}^r}\right)} \tag{2}$$

The maximum inverse saturation current under STC,

$$I_0^r = \frac{I_{sc}^r}{\left(e^{\frac{V_{oc}^r}{mV_T^r}} - 1\right)} \qquad (A) \tag{3}$$

The short circuit current, considering a linear function of radiation

$$I_{sc} = I_{sc}^r \frac{G}{G^r} \qquad (A) \tag{4}$$

The parameters that depend on the cell temperature

$$I_0 = I_0^r \left(\frac{T}{T^r}\right)^3 e^{\frac{\varepsilon}{m'}\left(\frac{1}{V_T^r} - \frac{1}{V_T}\right)} \qquad (A) \tag{5}$$

Where ε is the silicon energy gap *(ε=1.12 eV*) and m', the equivalent ideality factor.
The cell temperature T must be computed in each condition of radiation and air temperature

$$T = \theta_c + 273.16 \qquad (K) \tag{6}$$

$$\theta_c = \theta_a + \frac{G(NOCT - 20)}{800} \quad {}^{\circ}C \tag{7}$$

where θ_a is the ambient temperature (^oC); G the solar radiation (W/m^2); $NOCT$ the normal operation cell temperature ($NOCT = 45^{\circ}C \pm 2^{\circ}$), it represents the temperature of a cell at $G=800$ W/m^2 of $\theta_a = 20^{\circ}C$ ambient temperature.

There is a non-linear relationship between the voltage (V) and the current (I) at the terminals of the PV array,

$$I = I_{sc} - I_0\left(e^{\frac{V}{mV_T}} - 1\right) \qquad (A) \tag{8}$$

The power generated in DC can be computed by

$$P = V \times I = V\left[I_{sc} - I_0\left(e^{\frac{V}{mV_T}} - 1\right)\right] \qquad (W) \tag{9}$$

The relation between voltage and power is also non-linear and a maximum power point can be detected. This maximum power point voltage can be analytically computed by *dP/dV=0* and solved by implicit equation 10.

$$I_{sc} - I_0\left(e^{\frac{V_{mp}}{mV_T}} - 1\right) - \frac{V_{mp}I_0}{mV_T}e^{\frac{V_{mp}}{mV_T}} = 0 \tag{10}$$

Current at maximum power point using equation 8, with $V=V_{mp}$ and $I=I_{mp}$
Maximum DC power

$$P_{mp} = V_{mp} \times I_{mp} \qquad (W) \tag{11}$$

The AC output power is computed considering the inverter and MPPT (Maximum Power Point Tracker) performances

$$P_{ac} = P_{mp} \times \eta_{inv+MPPT} \qquad (W) \tag{12}$$

3.2. Solar regional data base and location selection

In this research PVGIS climate-SAF was used as reference solar database for the selected countries. (PVGIS). The main parameters influencing the PV system energy output in a specific location are the irradiation and air temperature. The annual Direct Normal Irradiation (DNI) for a fixed orientation of 35º for the PV modules in each of the selected places varies from 1350kWh/m^2 in the north of France to 2180kWh/m^2 in the south of Spain. In each country, 3 different sites were chosen (north centre and south) and aggregated information was computed for a 1kW of PV modules installed and is described in table 2.

Table 2 – Annual DNI at 35% inclination and full load hours in the selected location

Country	City	Latitude	DNI (35%) kWh/m2	Annual full load hours
France	Paris	48°51'23" N	1370	1030
	Lyon	45°45'50" N	1540	1160
	Marseille	43°17'47" N	1940	1470
Italy	Milan	45°27'55" N	1680	1270
	Rome	41°54'10" N	1930	1440
	Sicilia	37°35'59" N	2060	1550
Greece	Salonica	40°38'24" N	1940	1460
	Athens	37°59'2" N	2090	1570
	Heraklion	35°20'19" N	2100	1570
Spain	Bilbau	43°15'45" N	1490	1130
	Madrid	40°25'0" N	2070	1560
	Sevilla	37°23'20" N	2180	1600
Portugal	Oporto	41°9'28" N	2000	1490

	Lisbon	38°43'20" N	2020	1500
	Beja	38°0'55" N	2150	1580

For self-consumption computation the hourly DNI data in each site is used in conjunction with local hourly temperature to hourly PV energy generation simulation.

3.3. *Prosumers* annual PV generation and energy balance

Fig. 4 shows a schematic outline of the power profiles of on-site PV generation and power consumption. The area A+B is the total energy demand and the area B+C is the total PV energy generated. Self-consumption is thus the self-consumed part relative to total production.

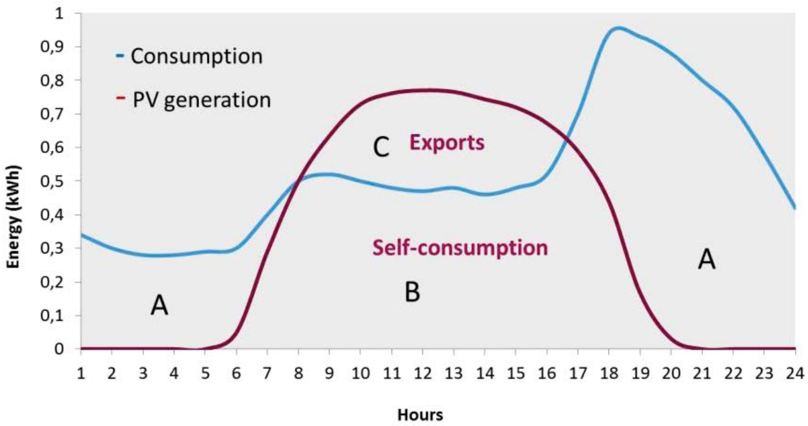

Fig. 4 – Schematic outline of a daily energy balance of a residential PV *prosumer*

$$self - consumption = \frac{B}{B+C} \quad (13)$$

The self-consumed part relative to total load is also a computed metric named self-sufficiency.

$$self - sufficiency = \frac{B}{A+B} \quad (14)$$

More formally, let *L(t)* the instantaneous building power consumption, *P(t)* the instantaneous PV power generation. The power generation used on site is

$$M(t) = min\{L(t), P(t)\} \quad (15)$$

Self-consumption and self-sufficiency are defined as

$$\varphi_{SC} = \frac{\int_{t=t1}^{t2} M(t)dt}{\int_{t=t1}^{t2} P(t)dt} \quad (16)$$

$$\varphi_{SS} = \frac{\int_{t=t1}^{t2} M(t)dt}{\int_{t=t1}^{t2} L(t)dt} \qquad (17)$$

3.4. Economic Assessment

For a PV *prosumer* there are two kinds of benefits: The energy savings due to self-consumption and the revenues due to the surplus energy produced and exported to the grid. The costs associated are mainly investment costs in the PV system, although in some cases it could be considered annual operation and maintenance costs and costs associated with the use of the electric networks that depend on the PV power installed. The generation costs of any electricity plant are computed using the *LCOE* (Levelized Cost of Electricity). The *LCOE* is defined as the cost assigned to every unit of energy produced by the system over the lifetime period,

$$LCOE = \frac{I_a + o\&m}{E_a} \qquad (18)$$

where I_a is the annualized capital cost of the plant, *o&m*, are the annual operating and maintenance costs and E_a the expected annual energy generated.

$$I_a = \frac{I}{k_a} \qquad (18)$$

where I is the total initial investment and k_a the annuity factor.

$$k_a = \frac{1}{r} - \frac{1}{r(1+r)^n} \qquad (19)$$

where r is the discount factor (assumed to be constant) and n is the economic life of the plant.

If the *prosumer* was paid at the same retailer price of the electricity he/she consumes, the *prosumer* profits could be easily computed by the difference between retailer electricity price (*RP*) and *LCOE* and the *NPV* as equation 20

$$NPV = (RP - LCOE) \cdot E_a \cdot k_a \qquad (20)$$

Under different values of *RP* and PV sales price (*SP*), and considering the percentage of self-consumption, φ_{SC}, the *NPV* should be computed as in equation 21

$$NPV = \left(RP - \frac{LCOE}{\varphi_{SC}}\right) \cdot E_a \cdot \varphi_{SC} \cdot k_a + SP \cdot E_a(1 - \varphi_{SC}) \cdot k_a \qquad (21)$$

The first term represents the savings along the system life cycle due to self-consumption and the second term represents the revenues due to the surplus energy sold to the grid.

4. RESULTS AND DISCUSSION

Location has a great effect on PV energy production, but the cost of PV systems, retail electricity prices, export electricity tariff and the percentage of self-consumption define in conjunction with PV generation, the level of economic benefits of PV *prosumers*. Table 3 summarises the main results of each of the selected countries. For Italy, due to high retailer electricity prices and low investment costs on PV systems, with less than 50% self-consumption the project's NPV becomes positive, while on the other side, France with low retailer prices and high PV investment costs, the LCOE for PV is higher than retailer prices (PV investments should be less than 2200€/kW in the south and at least 90% of self-consumption).

Table 3 – Summary of expected results for minimum self-consumption level

Country	France	Italy	Greece	Spain	Portugal
Project life time (n)	25				
Discount rate % (r)	6				
Capital Cost (€/kW)	3000	1750	2000	2200	2500
Annual O&M costs (€/Wh)	a)				
Electricity price (€/kWh) b)	0,1384	0,2227	0,1564	0,1908	0,1856
Export tariff (€/kWh) c) – f)	0,048	0,0558	0,0523	0	0,0432
PV generation (kWh/kW)	1030	1270	1460	1130	1490
	1470	1550	1570	1600	1580
LCOE (€/kWh)	0,228	0,108	0,107	0,152	0,131
	0,160	0,088	0,100	0,108	0,124
Min Self-consumption (%)	-	48	69	80	75
	-	40	64	57	68

a) O&M costs were neglected in this analysis b) (Eurostat 2015) c) (OMIE 2015) d) (GME 2015) e) (PV-tech) f) (Hellenic operator of electricity market, 2015)

Residential consumption usually peaks at 8am and 8pm while PV production is at its highest between 10 am and 3 pm, and under these conditions it is difficult to attain a high level of self-consumption so the majority of the energy produced will be exported to the grid instead of self-consumed unless the PV power installed is very low. Fig. 5 shows how NPV and IRR with self-consumption and self-sufficiency evolve with the PV power installed.

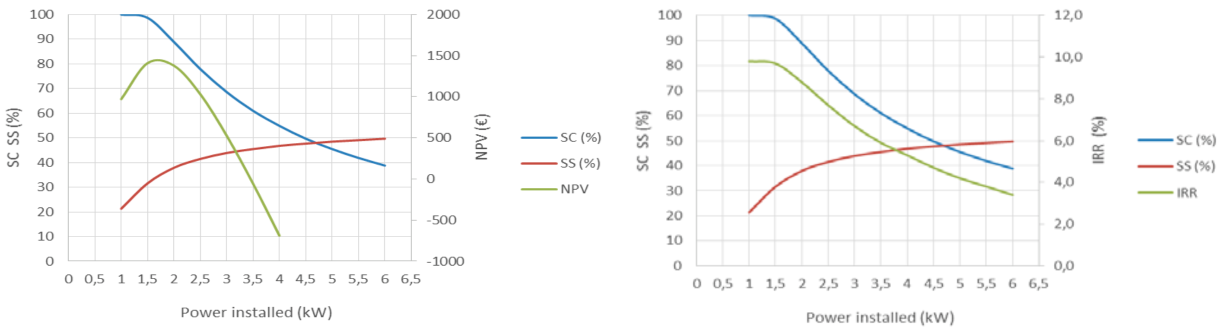

Fig. 5 – Evolution of NPV, IRR, SC and SS with PV power installed regarding a typical load profile of a *prosumer* in the south of Portugal

In this case, NPV is maximum at 95% of self-consumption which is attained at 1.75kW of power installed.
Several simulations were made in different sites and with different consumer types. Fig 6 represents an example of the typical load diagrams for a residential and a commercial *prosumer* considering the power installed for the NPV maximization. The optimal power installed for a commercial customer is much higher than for a residential. In this case self-sufficiency is 48% for a commercial client and for a residential only 31%.

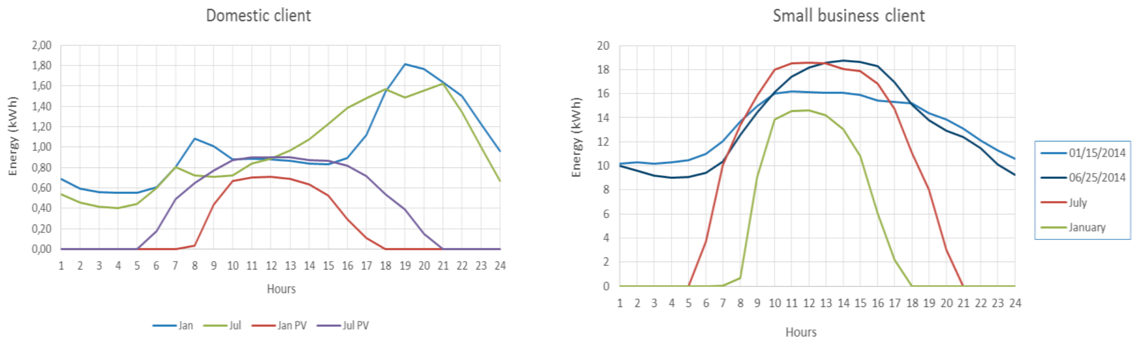

Fig. 6 – Typical winter and summer load and production profiles for domestic and commercial customers

The coincidence between consumption and PV generation is thus one of the major factors that make the PV investment the best economic and environmental solution. Load shifting measures could help in increasing self-consumption level for residential customers allowing more PV power installation.

5. CONCLUSIONS

The expected economic gains for a PV *prosumer* depend on many factors: location, PV system prices, retailer electricity prices, national policies and load/production adequacy. A location with high radiation, cheap PV systems, high retailer electricity costs and governmental policies that do not penalise PV producers with net access costs is the best combination for maximizing *prosumers* NPV especially if the consumer power follows the PV generation increasing PV power and self-sufficiency. A residential customer installing a grid-connected PV system, is paid for the exported electricity less than 5 c€/kWh (or nothing) by the electricity provider while charging about 18c€/kWh for the same kWh. At this exchange rate it is obviously more economical to consume than to export. In fact NPV maximizes at a 95% of self-consumption in the best case studies which usually is attained with small percentage of self-sufficiency and low power installed. With further increase of retail electricity prices and decrease of PV costs the business case for storage may become economically interesting for residential customers with the advantage of increasing self-sufficiency and decreasing even more electricity demand for the centralized power systems.

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Evaluating the impact of new renewable energy in the peak load - An ARDL approach for Portugal

Flávio Rodrigues Serras[1], António Cardoso Marques[1,2], José Alberto Fuinhas[1,2]

[1] *University of Beira Interior, Management and Economics department and* [2] *NECE-UBI, Estrada do Sineiro, 6200-209 Covilhã, Portugal, ffrserras@gmail.com*

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ABSTRACT

The increasing integration of renewable electricity generation, namely the new renewables (photovoltaic and wind), causes a change in the way the traditional notion of peak load should be considered. This integration will lead to demand surplus, whenever the need for generation from combined cycle plants increases. That happens whenever the demand increases is not followed by the new renewables generation. This paper focuses in Portugal, which is a country with great integration of wind power and recently with major investment in solar power. Monthly data are used for the period from July 2007 to September 2015, with a total of 99 observations. Taking into account the different stationary properties of the variables, the ARDL approach is performed. This approach allows to observe the short- and long-run effects; it allows I(0) and I(1) series; and it is less restrictive. Four ARDL models have been developed in order to verify the different relationships between generation from coal and total thermal (coal and combined cycle plants powered by natural gas) sources with the electricity demand and net load. The results show that coal energy has little flexibility and so its management does not contribute to smooth the new renewable intermittency problems. However it is essential for network security due to its baseload function. For that reason, there are long-run positive relationships, which are observed between the new renewables and the electricity generation by coal. However it appears that coal energy generation contributes to the increase in exports when production of other types of generation is abundant, causing the system to benefit from MIBEL prices whenever the prices are higher than the generation costs. The results further demonstrate that the inclusion of the new renewables in the electricity system causes significant changes in demand surplus leading to a greater need for combined cycle generation. Thus, the results suggest that a differentiated price policy will only be effective if, instead of consumption, the focus is on net load.

KEYWORDS: Net load, New renewables, Combined cycle, ARDL, Demand surplus.

1 INTRODUCTION

The new renewable sources (hereafter NRES) are characterized by intermittent generation with variable costs close to zero. However, the penetration of NRES implies high initial investment costs. These costs are an obstacle to the investors and therefore the generation by NRES sources would have to be subsidized. The most common contracts used to finance wind power and solar energy are the feed-in tariffs, which provide the NRES with dispatch priority at a fixed price throughout the period of consumption/generation (Ramli & Twaha, 2015; Ritzenhofen & Spinler, 2014).

In order to analyze the problem of the new renewables intermittency it is crucial to define the notion of net load. The net load is defined in the literature as the demand electricity minus total renewable energy (Chaiamarit & Nuchprayoon, 2014; Tarroja, Mueller, Eichman, & Samuelsen, 2012) or minus wind power (George & Banerjee, 2011; Hedegaard & Meibom, 2012). In this paper the electricity net load (hereafter ENL) is defined as the demand for electricity minus the supply from wind and solar power.

With non-renewable sources, the variable costs vary with the prices of raw materials. As such when there is higher consumption, the demand for raw materials also increases leading to an increase in its price. Thus, before the integration of new renewables it is crucial to smooth the load diagram by decreasing consumption peaks. The consumption peak corresponds to the generation peak of the total thermal sources. The following Fig.1 serves as an example of the demand surplus before the integration of new renewables.

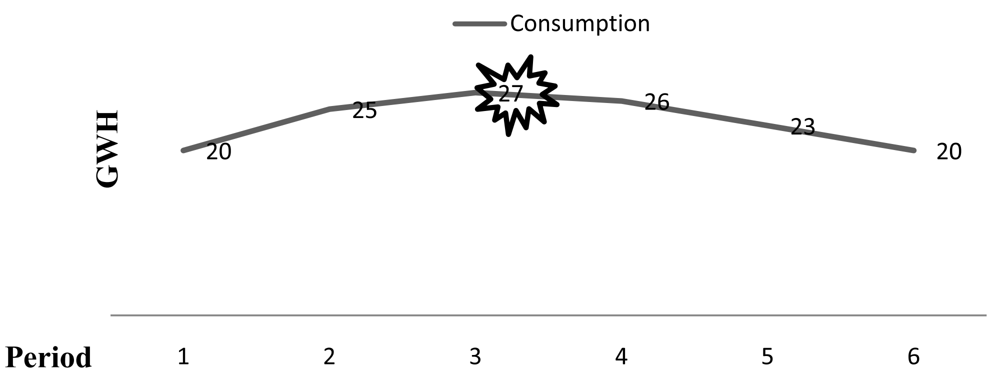

Fig. 1: Demand surplus before the new renewables integration

The example (Fig.1) corresponds to a situation of the electricity demand in GWh over a period of 6 hours on a given day. Values are merely illustrative.

So, before the NRES integration, the critical consumption would be in the period 3, i.e., a consumption of 27 GWH.

Considering the intermittent nature of resource availability, the peak pricing concept has to be adapted to the new energy mix challenges.

Since the NRES are intermittent, the firstbest scenario of accomodation to these renewables is when demand follows the availability of the natural resources. That is, the higher costs of electricity may not be present in times of higher consumption. This will happen whenever the need for generation from thermal sources increases. The following Fig. 2 helps to illustrate the ENL concept.

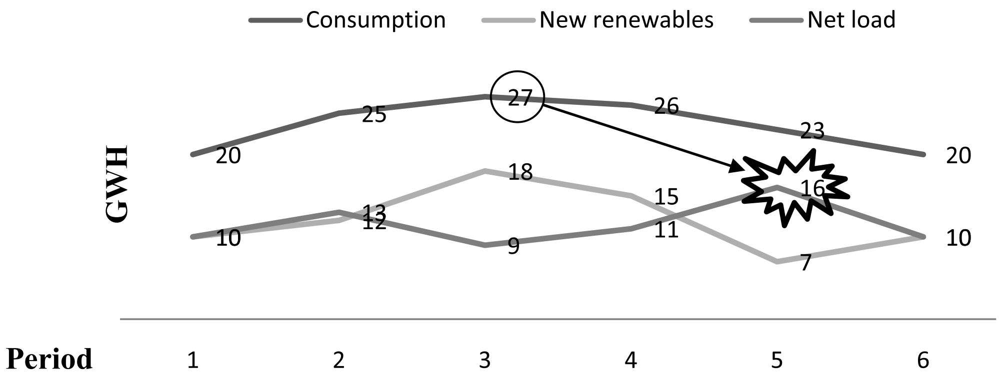

Fig. 2: Demand surplus with new renewables integration

In Fig. 2, there is a change regarding the period of peak consumption due to the new renewables, i.e., the peak period is not period 3 (consumption = 27 GWh) but period 5 (consumption = 23 GWh). This peak change is due to the greater need for electricity production by thermal sources during period 5. Thus it can be seen that, with the integration of the renewables, the most problematic moments are the peaks observed in the net load since it is at these times that renewable production is lower.

This paper is looking to answer the question: could intermittent electricity contribute to the reduction of the demand surplus? The objectives are to identify the differences between the presence and absence of the combined cycle generation in relation to consumption and ENL. Through the enunciated relationship, the impact of NRES on the remaining generation sources will be identified. To do that, the paper focus on Portugal, wich is a country with great integration of wind power and one of the most insolations countries in Europe. The main outcome shows that the NRES, by not following the increases of electricity demand, causes an increased need for generation of combined cycle plants.

The article is developed as follows: section 2 presents the literature review; section 3 is devoted to presenting the data and methodology used and the preliminary results; section 4 present the main results as well as its robustness checks; section 5 discusses the results; and Section 6 concludes.

2 LITERATURE REVIEW

In order to reduce the emission of greenhouse gases (GHG), some European countries have set targets for RES integration. By 2020 the goal is for that at least 20% of energy consumption is to be from renewable sources (Directive 2009/28/EC) and for this amount to reach 27% by 2030 (http://ec.europa.eu/energy/en/topics/energy-strategy/2030-energy-strategy).

To achieve this goal, several forms of electricity generation from NRES have been added to the energy mix of European countries (Huber, Dimkova, & Hamacher, 2014). NRES have the characteristic of intermittent generation, not dispatchable. Due to its intermittence, the adoption of these new NRES causes changes in electricity demand characteristics (Chaiamarit & Nuchprayoon, 2014). Intermittent energy causes the need to increase the flexibility of the electricity market (Huber et al., 2014). However, the coal thermal power plants with carbon capture have low flexibility (Brouwer, van den Broek, Seebregts, & Faaij, 2014). This should provide the sources of combined cycle, which are more flexible, and the ability to ensure a faster response to the most sudden changes in production of new renewable (Barelli & Ottaviano, 2015).

There is evidence in the literature that the generation of electricity from new renewables causes a higher reduction in the base-load and intermediate-load than in the peak-load (Chaiamarit & Nuchprayoon, 2014). In this perspective it is necessary to consider the impact of new renewables in order to define the changes that occur in all of the load groups (base, intermediate and peak).

The impact of renewable energy integration is considered, sometimes, as capacity savings as well as savings in the CO2 emissions costs (George & Banerjee, 2011). However, savings in electricity capacity do not always follow the reduction of the costs. There is evidence in the literature that the renewable energy contributes to smaller price fluctuations, which in itself does not guarantee that these are lower, since prices depend on the penetration of renewables (Chaiamarit & Nuchprayoon, 2014). Larger penetration of renewables requires backup capacity as well as flexibility to manage surplus, such as pumping or exports. These requirements may be reduced in the future because in a situation of a great penetration of wind power there are moments when the net load would be negative, i.e., renewable production would exceed the demand for electricity. In that scenario there are two alternatives, the excess electricity is storaged (equivalent to the current pump) or the demand must have high flexibility (which could reduce the need for backup) (Hedegaard & Meibom, 2012). However, there is evidence in the literature of the concept of V2G/G2V of electricity, of electricity, which consists in the utilization of electrical cars as storage/supply components in the electricity grid, to be a combination of the two previous alternatives (Morais, Sousa, Vale, & Faria, 2014).

It is often reported in the literature that in order to accommodate renewable energy it is necessary to store it. It is indicated in the literature that the existence of renewable energy surplus (negative net load) does not allow the use of all the electricity from renewable sources, and therefore larger amounts of energy are wasted the greater the renewable energy penetration is (Tarroja et al., 2012).

3 METHODOLOGY

3.1 Data:

Monthly data are used for the period from July 2007 to September 2015, with a total of 99 observations. The selected period begins in July 2007 since it was on that date that the MIBEL market between Portugal and Spain went established. September 2015 is the most recent date at the time of data collection. All data is available on REN’s Monthly Statistics, except MIBEL prices which were collected from the OMIE. Table 1 lists the variables and summary statistic.

Table 1
Variables and summary statistics

Variable	Descriptive Statistics				
	Obs	Mean	Std dev.	Min	Max
COAL	99	1229.687	396.2385	267	2198
TERMOR	99	1548.556	509.0514	313	2639
CONS	99	4162.465	278.25	3728	4920
CARLIQ	99	3377.374	361.5209	2698	4301
NRE	99	785.0909	305.6216	271	1655
RE	99	679.8788	135.8636	429	988
HYDRO	99	847.4545	520.3952	291	2350
MIBEL	99	47.5535	12.8933	15.39	76.55
BOMB	99	80.9697	37.2124	22	191
REXP	99	2.3529	4.8002	1	37.1364

Thermal energy is generally the backup power source for new renewables (NRE) and as such, its interaction with the photovoltaic and wind energy is decisive. Knowing that thermal energy is divided into coal energy and total thermal energy (coal and combined cycle). The impact of combined cycle is determinant because its flexibility characteristic serves as a response to the new renewables intermittency. Thus the coal source (COAL) and total thermal sources (TERMOR) are defined as the dependent variables.
In order to understand the relationship between the different thermal sources and the new renewables, in a perspective of assessing the impact of new renewables on peak load, it is carried out an indirect relation by measuring the consumption (CONS) and the electricity net load (NLOAD), i.e., CONS minus NRE.
The other factors that influence the thermal generation are all the remaining sources of electricity generation and/or import/export to ensure that all consumption of electricity is satisfied. They are, the renewables (RE), composed mostly of thermal biomass; hydroelectric generation under the ordinary regime (HYDRO); pumping (BOMB); the export/imports ratio of electricity (REXP); and also MIBEL's market electricity prices for Portugal (MIBEL) because of its potential influence on dispatchable generation.

3.2 ARDL approach:

The fact that any electricity system, which also includes Portugal's system, is managed in real time, leads to endogeneity between variables. To deal with the endogeneity the VAR/VEC model is often used. However the ARDL model (Pesaran, M. H., Shin, 1999) is also suitable in the presence of endogeneity and cope well with. The uncertainty about the order of integration of the variables, only ensuring that no variables is I(2) are present. This is just our case (see Table 2). The ARDL also allows checking the short and long-run effects between the variables.
The ARDL model is specified as follows:

$$\Delta y_t = c + \sum_{i=1}^{k} \beta_i \,.\, \Delta y_{t-i} + \sum_{i=0}^{k} \beta_{i+2} \,.\, \Delta x_{t-i} + \beta_{i+3} . y_{t-1} + \sum_{i=0}^{k} \beta_{i+4} \,.\, x_{t-1} + \beta_{i+4} ID + \varepsilon_t,$$

where y=[COAL, TERMOR] are the dependent variables in the estimated models; x=[CONS, NLOAD, NRE, RE, HYDRO, MIBEL, BOMB, REXP, ID] corresponds to the exogenous variables in the models; c is the constant; β_i and β_{i+3} are the coefficients of the dependent variables; β_{i+2} and β_{i+4} are the coefficients of the explanatory variables; y_{t-i}, y_{t-1}, x_{t-i} and x_{t-1} correspond to the lags of the dependent and explanatory variables, respectively; and ID corresponds to the dummies used to control for the outliers.

Given that relative changes are more representative than absolute ones, the varibles were transformed to its natural logarithms. Thereafter the prefix L means natural logarithm of the variables. To ascertain the order of the variables integration, traditional unit root tests were performed (Table 2). They are Augmented Dickey-Fuller (ADF) (Dickey & Fuller, 1979), Phillips-Perron (PP) (Phillips & Perron, 1988) and Kwiatkowski-Phillips-Schmidt-Shin (KPSS) (Shin, Kwiatkowski, Schmidt, & Phillips, 1992).

Table 2
Unit roots tests.

Variables		ADF			PP			KPSS	
		C	CT	None	C	CT	None	C	CT
LCOAL	Level	-4.2414***	-4.3620***	-0.2583	-4.3018***	-4.4653***	-0.2219	0.4558*	0.1253*
	1st dif	-11.103***	-11.065***	-11.162***	-11.403***	-11.371***	-11.470***	0.0472	0.0230
LTERMOR	Level	-3.7785***	-4.1698***	-0.2386	-3.8271***	-4.3067***	-0.2007	0.7227**	0.0867
	1st dif	-10.910***	-10.866***	-10.968***	-11.441***	-11.406***	-11.513***	0.0587	0.0356
LCONS	Level	-0.5642	-1.2857	-0.5582	-5.2107***	-5.1735***	-0.4668	0.3293	0.0639
	1st dif	-4.9629***	-4.9291***	-4.9563***	-18.940***	-19.059***	-19.071***	0.1963	0.1709**
LCARLIQ	Level	-1.1926	-7.6017***	-2.5809**	-4.6164***	-7.5406***	-0.9683	1.2989***	0.0986
	1st dif	-4.4937***	-4.5878***	-3.9824***	-42.171***	-41.916***	-33.105***	0.1892	0.1652**
LNRE	Level	-3.0658**	-5.1910***	2.6952	-3.7209***	-5.1899***	0.4197	1.1435***	0.1678**
	1st dif	-7.3250***	-8.0577***	-6.6223***	-13.374***	-13.393***	-13.417***	0.1418	0.0616
LRE	Level	-2.4383	-2.7842	0.2964	-2.4459	-2.9330	0.3179	0.9434***	0.2578***
	1st dif	-10.705***	-10.719***	-10.744***	-10.702***	-10.720***	-10.739***	0.0859	0.0236
LHYDRO	Level	-4.5653***	-4.6929***	-0.2927	-3.6844***	-3.7568**	-0.3632	0.2289	0.0607
	1st dif	-8.1045***	-8.0739***	-8.1483***	-8.1077***	-8.0769***	-8.1515***	0.0339	0.0291
LMIBEL	Level	-3.5990***	-3.6212**	-0.2200	-3.5990***	-3.6212**	-0.1139	0.1674	0.1031
	1st dif	-9.9091***	-9.8567***	-9.9604***	-10.543***	-10.474***	-10.616***	0.0582	0.0522
LBOMB	Level	-3.6322***	-4.5894***	-0.0022	-3.4171**	-4.5979***	0.0162	0.8674***	0.0927
	1st dif	-12.187***	-12.124***	-12.239***	-13.469***	-13.392***	-13.507***	0.0457	0.0452
LREXP	Level	-4.8508***	-5.0611***	-4.1142***	-4.9841***	-5.2172***	-4.2167***	0.4343*	0.0475
	1st dif	-10.385***	-10.332***	-10.439***	-15.877***	-15.832***	-16.000***	0.0886	0.0797

Notes: None denote without constant and trend; C denotes constant; CT denote constant and trend.
***, **, * Denotes significance at 1%, 5% and 10% level respectively.

During this period some phenomena are observed which reveals with statistical significance. They are, a break that occurs every year around April/May in hydro generation. Considering that the beginning of 2012 was characterized by little rain, this led to the months of January/February to have little ability for hydroelectric generation, and hence the structural break in April/May

2011 was included in the model (dummies ID2011:05 and ID2011:04). It was also considered the case in which the MIBEL price reached a minimum (dummy ID2010:03). In the same way, the peak in the MIBEL price (dummy ID2013:12) was considered.
Two more breaks were identified throughout the Zivot-Andrews unit root test (Zivot & Andrews, 1992):

Table 3
Break point test.

Variables	Zivot-Andrews test statistic	Chosen break point
LCONS	0.0401**	ID2009m12
LMIBEL	0.0152**	ID2008m12

The date that marks the renewable upward trend and the downward trend of the entire thermal energy; represented by the dummy ID2009:12. The downward trend in the MIBEL price; represented by the dummy ID2009:01 (a following month was chosen for the observation of residues)**.**
The follow diagnostic residual tests were performed: the ARCH test for heteroscedasticity; Breusch-Godfrey serial correlation LM test; Jarque-Bera normality test, stability coefficients test of CUSUM and CUSUM of squares and Ramsey RESET test. The robustness of the models were also checked.

4 RESULTS

After confirming that no variables is I(2), the ARDL model were estimated. It were estimated four ARDL models (I, II, III and IV), namely two have COAL as the dependent variable (I and II) and the remaining two (III and IV) have the TERMOR as the dependent variable, i.e., with the sum of the cycle combined with the coal source. Taking into account each dependent variable, an analysis was performed in comparison to the consumption and the net load.
The model I includes the relationship between COAL and consumption CONS. The model II considered the relationship between the COAL and NLOAD. The model III relates the TERMOR to consumption CONS. Finally the model IV relates the TERMOR to the NLOAD. It is to be highlighted that when the NLOAD is considered, both the CONS variable and the NRE variable are excluded because the NLOAD corresponds to the CONS subtracted from the NRE.
Several tests have been applied to ensure the robustness of the models. Heteroskedasticity Test: ARCH, with the null hypothesis: homoscedasticity, which proved to be homoscedasticity for all models, in the first and second orders; Breusch- Godfrey Serial Correlation LM test, with the null hypothesis: no correlation in the series, proving also that in the four models there is no correlation of errors, in the first, second and third orders, except in the second order for model II; Jarque-Bera normality test confirms that in all models the error term follows normal distribution; and finally, another test was carried out on the stability coefficient, Ramsey RESET test also confirms that there is stability in the model.

Table 4 summarizes the tests carried out on all four models:

Table 4
Diagnostic tests.

Test	I – LCOAL (LCONS)	II – LCOAL (LCARLIQ)	III – LTERMOR (LCONS)	IV – LTERMOR (LCARLIQ)
ARS	0.8459	0.8408	0.8752	0.8762
Jarque-Bera	0.7269	0.8587	0.5763	0.5758
LM	(1) 0.2377 (2) 0.4573 (3) 0.3956	(1) 0.6906 (2) 0.0793 (3) 0.1346	(1) 0.9645 (2) 0.5982 (3) 0.7935	(1) 0.9925 (2) 0.9657 (3) 0.9952
ARCH	(1) 0.3512 (2) 0,2396	(1) 0.1894 (2) 0.3152	(1) 0.4098 (2) 0.5299	(1) 0.1207 (2) 0.2476
RESET	0.4155	0.2831	0.7964	0.8741

Notes: Diagnostic test results are based on F-statistics. () represents lags for the variables. ARS denoted Adjusted R-squared. Jarque-Bera is a normality test. LM is Breusch-Godfray serial correlation LM test. ARCH denotes ARCH test for heteroscedasticity. RESET is stability Ramsey RESET test.

The stability coefficient CUSUM and squares CUSUM test also suggests that there is stability in all models (Fig.3):

Cusum Test **Cusum of Squares Test**

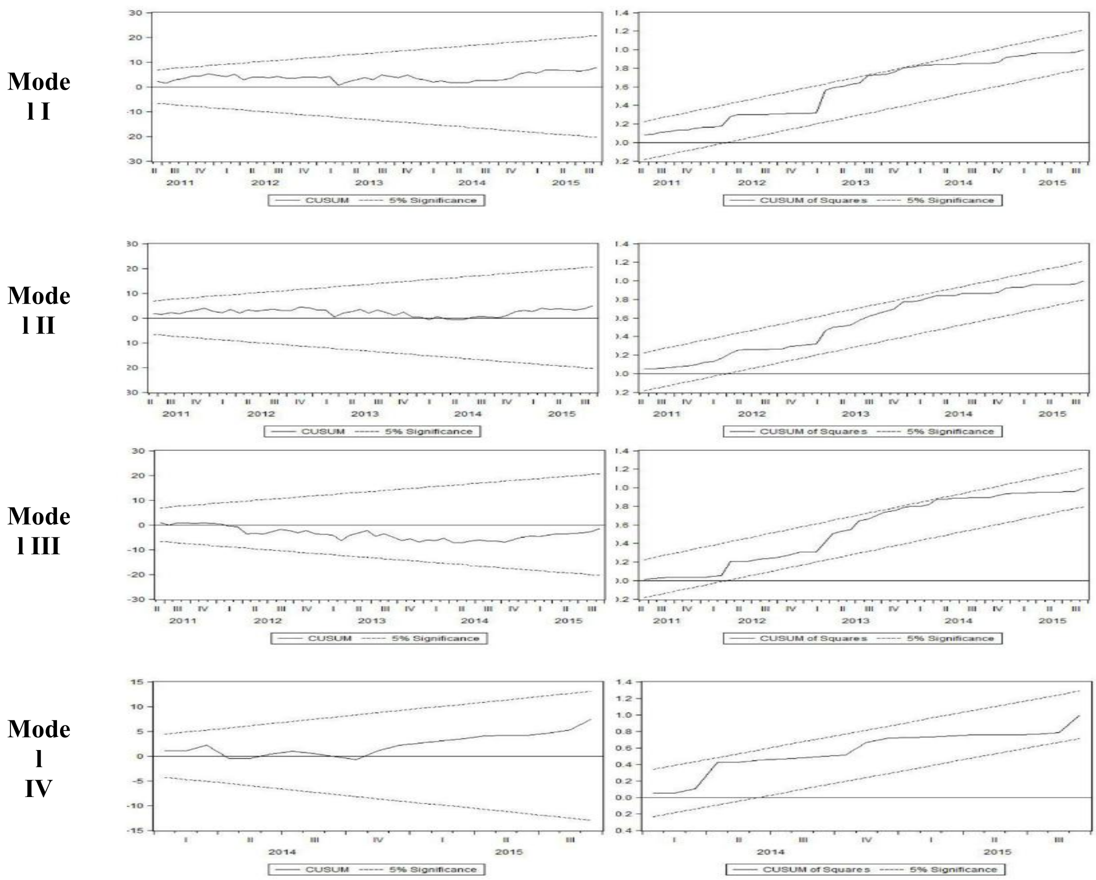

Fig.3: CUSUM and squares CUSUM

The stability coefficient CUSUM and CUSUM of Squares Tests also suggests that there is parameter stability in all models. In model I, II and III the period calculated is from 2011:04 to 2015:10; In model IV the period calculated is from 2014:01 to 2015:10. The periods used in the CUSUM and square CUSUM tests differ in model IV due to the utilization of dummies.
Table 5 summarizes the elasticities and semi-elasticities of all four models:

Table 5
Semi-elasticities and elasticities.

Semi-elasticities	D(LCOAL)		D(LTERMOR)	
	Model I	Model II	Model III	Model IV
D(LCONS)	0.6742***	---	0.7966***	---
D(LHYDRO)	-0.3038***	-0.2292***	-0.2675***	-0.2563***
D(LMIBEL)	0.9974***	1.0696***	0.8376***	0.8576***
D(LREXP)	0.1620***	0.1518***	0.0806**	0.0995***
D(LNLOAD)	---	0.4085**	---	0.7161***
D(LNRE)	---	---	-0.1542***	---
Elasticities				
LNRE(-1)	0.5794***	---	---	---
LRE(-1)	-1.8261***	-1.2716***	-0.9608**	-0.8356**
LHYDRO(-1)	-0.2636**	---	---	---
LMIBEL(-1)	---	0.3921*	---	---
LBOMB(-1)	---	0.2101**	---	---
LREXP(-1)	---	---	-0.3378**	-0.3708***
ECT(-1)	-0.3243***	-0.3056***	-0.2189***	-0.2239***

Notes: ECT denote Error Correction Term.
***, **, * Denote significance at 1%, 5% and 10% level respectively.

The elasticities was obtained through the negative relation between the ECT and the variables coheficients on the long-run, i.e., $-(\frac{ECT}{\beta_{i+4}})$.

5 DISCUSSION

In models I and II, the short-run causality between LHYDRO, LMIBEL and LREXP and dependent variable LCOAL are all in the same direction and of similar dimensions. In the long-run the negative elasticity with the LRE is higher in model I. Yet in the long-run, in the model I there is a relationship with LNRE and LHYDRO, while in the second model the relationship occurs between LMIBEL and LBOMB.
In models III and IV the short-run relationships between the LHYDRO, LMIBEL and LREXP and the dependent variable remains in the same direction and with very similar dimensions, whilst there is a negative relationship with LNRE. In the long-run, the relationship between the dependent and LRE continues to be negative with a greater dimension in model III (with consumption (LCONS)), and there is a negative relationship with LREXP.
In model I/II and III/IV, the relationship with LCONS and LNLOAD is greater for consumption although of smaller dimension in models III/IV.

5.1 Short-run relationships

In the all models the short-run relationship with the hydro energy is negative which means that, when hydro availability is greater, the need for thermal output is lower. This is in the same line of thought of what happens with the new renewable considering that the thermal sources have higher generation costs.
The relationship with the MIBEL prices (LMIBEL) is positive, indicating that when the price of MIBEL is higher there is a greater predisposition to produce thermal electricity in order to benefit from its export. The existing relationship is reduced in models III/IV (coal with combined cycle), which is expected due to higher prices of generation of the combined cycle plants and for this reason its generation export is less efficient.
The relationship with the export ratio is positive, i.e., the higher export the greater the generation by thermal sources. This relationship is connected to MIBEL prices, since the export takes place at the price of MIBEL and therefore it is confirmed that there is a thermal electricity generation to export. The decrease in this ratio, for marginal values, in models III/IV is again indicative of the extremely specific and essential function of such combined cycle plants to respond to the intermittency of new renewables.
The negative relation with the new renewable is revealed only in model III and not in model I, which again leads us to conclude that there is substitutability between new renewable and combined cycle.

5.2 Long-run relationships

In the long run, there is a positive relationship between the new renewable and the total thermal energy in model I, this relationship isn't expected, however, because of poor flexibility of the coal, the output is relatively constant over the daily periods and for this reason there is a positive relationship with the new renewables.
In model I it is also observed a negative relationship with the hydro energy, which shows the existing substitutability between hydro and coal.
In Model II there is a positive relation with the MIBEL prices and pumping, this means that globally an increase in the MIBEL prices leads to increased coal generation, which is related to electricity export. The pump has a positive relationship that conforms to the existing opposing relation with the hydro generation. I.e., when there is hydro generation the coal generation tends to decrease, but when there is a pumping to displace hydro generation for future, the coal generation tends to increase.
A negative relationship is found in all models with renewables without intermittency (LRE), however, the relationship is of smaller dimension in III/IV models that consider the combined cycle, i.e., because the renewable (LRE) have dispatchable generation, within the availability of raw material (biomass), act as thermal substitutes, not replacing the generation of combined cycle that acts as backup of new renewables.
In models III/IV it is also observed a negative relation with the ratio of exports. Although the increase of the MIBEL price leads to the increased coal generation, the ratio of exports/imports causes a decrease on total thermal energy. We conclude that the rising price of MIBEL leads to increased coal generation due to the exports of other generation sources since, when the ratio of exports increases, there is less of a need for thermal generation due to surplus from other generation sources.

5.3 Relationship with the Consumption/Net Load

On models with the coal generation (I/II) it is observed a higher significant relationship between the coal generation and consumption than with the net load. This relationship is observed due to the coal generation being designed for longer periods because of its characteristic of lower flexibility. When the expected consumption is higher the level of coal generation is projected to higher generation, therefore not absorbing the variations that the intermittency of new renewables gives to the net load.

In models with the total thermal sources (III/IV), the relationship remains, although this time the relationship between the total thermal with the net load and the consumption presents approximate values. This relationship is observed because the total thermal takes into account the combined cycle that having flexibility as a characteristic serves as a backup to absorb the intermittency of new renewables. We can conclude that the increased net load influence on the total thermal generation is due to more pronounced peaks. This means that new renewables cause a greater need for backup power, increasing the pressure on the cycle combined plants, and therefore an electricity market that is more expensive.

Even with the frequency of monthly data, there are several moments, namely the night time, where the combined cycle is not necessary due to the abundance of new renewable. We can conclude that the impact of the consumption increases, by not being fully followed by new renewable, are significant and then an approximation is observed in the relationship with the net load and consumption.

A real-time pricing policy is necessary in order to control the times when demand is excessive and this surplus is no longer a surplus at peak consumption but on net peak loads.

It is also important to point out the importance of the electricity storage in the future, being that the excess of new renewable that is stored in the excess generation times could be used to smooth the net load surplus.

6 CONCLUSION

In general it is concluded that the thermal generation sources are essential for the stability of the electrical system. On the one hand, the coal source contributes to network security by providing an amount of generation substantially constant over the daily period. The generation amount varies inversely, in general, with the availability of hydro and biomass. On the other hand, the sources of the combined cycle by being more flexible contribute to system stability in the presence of wind and solar energy which are characterized by intermittent generation.

Coal energy that contributes to the baseload, also plays an important role in the exchange of electricity between Portugal and Spain. Although the relationship between the export ratio and total thermal power is negative, this relationship suggests that most of the export occurs only when the other generating sources are abundant, so only those sources are exported. However, when we observe that the increase in MIBEL prices causes increases over coal energy it suggests that the increase in coal serves to "release" power from other sources to the export target, and thus benefiting from the higher prices of MIBEL. So there is an important role of coal generation on the electricity exchange in the Iberian Peninsula through the MIBEL market.

When it comes to the new renewables, the net load is an essential measure to ascertain the impact of these on demand. A pricing policy on demand surplus cannot continue to focus on the excesses of consumption but on the surplus from the net load. That is, the new renewable variable costs are almost zero and therefore it is when the source of production has higher variable costs that a demand decrease is needed, and this excess will be observed on the net load because the net load represents all the consumption that will have to be satisfied by the existing production sources before the integration of new renewables.

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Econometric estimation of useful exergy augmented production functions: case study for Portugal 1960-2009

João Santos[1], Tiago Domingos[1], Tânia Sousa[1], Miguel St. Aubyn[2]

[1] *MARETEC – Marine Environment and Technology Center, Environment and Energy Scientific Area, Department of Mechanical Engineering, Instituto Superior Técnico (IST), University of Lisbon, Avenida Rovisco Pais, 1 1049-001, Lisbon, Portugal,* *joao.dos.santos@tecnico.ulisboa.pt*, *tdomingos@tecnico.ulisboa.pt*, *taniasousa@tecnico.ulisboa.pt*

[2] *UECE Research Unit on Complexity in Economics, Department of Economics, Instituto Superior de Economia e Gestão, University of Lisbon, Rua Miguel Lupi, 20 1249-078, Lisbon, Portugal,* *mstaubyn@iseg.ulisboa.pt*

ABSTRACT

Neoclassical and ecological economics contrast in the role attributed to energy in economic growth. Mainstream models assume that energy's marginal importance as a factor of production is justified by its small cost share. Because of this, and by also failing to account for the contribution to growth from quality-adjusting factors of production, these models are unable to fully explain growth, without resorting to a total factor productivity (TFP) component.

Ecological economics models, on the other hand, tend to consider energy the only relevant factor of production, and downplay the role of technical change, arguing that innovations mainly increase productivity by allowing the use of more energy.

We seek to reconcile these two strands of literature by applying an econometric approach, testing for cointegration linear combinations of output, capital, labor, and useful exergy. Useful exergy accounts, in exergy terms, for energy used productively in the economy. The linear form of cointegration vectors allows their interpretation as Cobb-Douglas functions, and we apply a set of criteria in order to narrow our analysis to economically plausible production functions. Focusing on a case-study for Portugal (1960-2009), we compare estimated production functions in terms of goodness-of-fit to real output and magnitude of TFP.

Our results show that for strictly capital-labor neoclassical models, cointegration isn't always observed, and even when it is present, most of growth is accounted by TFP. Output elasticities estimated in these models do not match observed cost shares for capital and labor. The estimated production function that best fits Portuguese growth is obtained when quality-adjusted capital/labor measures are included in the cointegration space, and two simultaneous cointegration vectors are observed between the variables: 1) a capital-labor production function, with estimated output elasticities matching observed cost shares; 2) a relationship allowing capital utilization to be estimated as a function of useful exergy and labor. In this case, the TFP component of growth is virtually eliminated. Neoclassical and ecological approaches are reconciled by having useful exergy inputs be essential to production, while retaining the standard cost shares associated with capital and labor.

KEYWORDS: Useful exergy, production function, cointegration, output elasticities, capital utilization

1 INTRODUCTION

The relationship between energy use and economic growth has sparked an ongoing debate between two seemingly contradictory views.

On one hand, neoclassical theory acknowledges two (freely substitutable) major factors of production: capital and labor. According to this view, in a state of market equilibrium – in which profits are maximized without technological constraints on factor combinations – and for a simple economy consisting of small price-taking firms, a factor's productive power (represented by its output elasticity) can be equated with its respective cost share in total output (Mankiw, 2014).

Historically, a stylized fact observed across countries verifies nearly constant (average) cost shares for capital (30\%, as interests and rents) and labor (70\%, as wages). Generally, payments to energy are not explicit on national accounts, and even when these payments can be roughly equated to revenues from energy industries (e.g. coal mining, electricity generation and distribution) energy's cost share is minimal for OECD countries (around 4-5\%), when compared with capital or labor. The small cost share of energy, associated with the simplifying assumptions from the neoclassical approach, have resulted in a consistent underestimation of the importance of energy in economic production, thereby excluding it from the principal growth models, in which energy is neither a constraint nor an enabler of economic growth (Aghion & Howitt, 2009).

However, a major criticism surrounding neoclassical growth theory is its inability to fully account for past growth with just the "conventional" factors of production. In a growth accounting framework, an indirectly-measured residual – corresponding to growth not explicable by measurable changes in either capital nor labor – is often found to be the major driver of growth within several economies (Easterly & Levine, 2002). In its original application, Solow (1957) estimated this residual (Solow residual, or total factor productivity - TFP) as accounting for over 85\% of growth in the US (1909-1949). While some prefer to regard it as a place holder for disembodied exogenous technological progress, an important strand of growth accounting studies has focused on reducing TFP, by breaking it down into its components (Jorgenson & Griliches, 1967; Maddison, 2013).

Jorgenson & Griliches (1967) recognized the importance of accounting for heterogeneity of capital and labor in order to accurately account for growth. For labor, this is often done by adjusting total hours worked for each worker's "skill", through a human capital index, thus obtaining a quality-adjusted labor (Whalley & Zhao, 2013; Manuelli & Seshadri, 2005). For capital, differences in productivity are usually taken into account by estimating capital services, rather than capital stocks, thus obtaining quality-adjusted capital. Since quality-adjusted measures generally grow faster than their unadjusted counterparts, its adoption has a significant effect in reducing TFP (Groth, Gutierrez-Dumenech & Srinivasan, 2004). However, it is important to note that there is a portion of TFP that cannot be "explained away" even when accounting for quality adjusted inputs, broader investment concepts or technological spillovers (van Ark, 2014).

Contrasting with the neoclassical view, arguments from the field of ecological economics claim that energy is an essential input to economic production, for neither capital nor labor can function without it, and that economic processes in the real world cannot be fully understood without accounting for energy use. This field distinguishes itself from neoclassical economics by arguing that the economy is embedded within a larger, environmental system with which it performs energy/matter transactions. Economic thinking and practice should therefore be grounded in physical reality, namely the laws of thermodynamics.

The field of ecological economics has attempted to endogenize and account for economic growth by explicitly incorporating energy as an independent factor in a standard production function approach. Adding a third independent factor implies that the output elasticity parameters must be computed independently from observed cost shares, by statistical fitting methods. This invalidates the implications of the "cost-share theorem" since the economic weight of each factor may be higher or lower than its cost share indicates. Furthermore, most growth models with energy do not include realistic constraints on the substitution possibilities between energy, labor, and capital. In fact, thermodynamic considerations suggest that production of a given level of output has minimum energy requirements (Stern, 1997), and energy scarcity will be a limiting factor to future growth (d'Arge & Kojiku, 1973; Kümmel, 1982; Kümmel, 2011; Gross & Veendorp, 1990; van den Bergh & Nijkamp, 1994; Lindenberger & Kümmel, 2011).

As with capital and labor inputs, the appropriate measure and aggregation of energy inputs to the production function framework will affect the estimated results for output and TFP. Ayres & Warr (2005) defend that energy inputs should be quantified not in terms of "raw" energy, but in terms of energy (in fact, exergy) actually converted to useful exergy (or useful work. When useful exergy is included as a third factor in a LINEX production function, Ayres & Warr (2005) manage to account for economic growth without the need for an exogenous residual from 1900-1975. Useful exergy measures the exergy flow in the economy at its useful stage, i.e. after all transformation and conversion losses just before being used to perform services in the economy. Useful exergy is, for example, the heat being delivered by air conditioning into our house to provide thermal comfort, or the mechanical work delivered by a car engine through the driveshaft to the tires to provide transport. It accounts for energy used productively in the economy, while still being measured in energy units (Joule or BTU).

For all its importance in ecological economics literature, a twofold criticism may be made on the work of Ayres & Warr (2005): 1) they adopt a non-standard production function (LINEX), which has found little acceptance within the economics community (Saunders (2008) indicated that the LINEX production function's thermodynamics considerations come at the price of not satisfying standard concavity conditions); 2) while adopting a quality-adjusted measure for energy inputs (useful exergy), they do not account for quality-adjusted measures of the remaining factors of production: capital and labor.

Can the neoclassical and ecological strands of economic theory be reconciled? In particular, can the essential role of energy in production be compatible with neoclassical assumptions, such as the cost share theorem? In this paper, we attempt to identify long-run economic relations by looking at joint statistical properties of economic data. Particularly, we seek to estimate aggregate production functions and corresponding output elasticities for capital, labor, and energy inputs through cointegration analysis. We expect to reconcile insights from both neoclassical and ecological economics, while also contributing to interdisciplinary dialog by adopting standard econometric techniques in our analysis.

We adopt a multivariate approach to test for cointegration, since we expect to find statistically significant relationships between economic output and *all* relevant input factors, rather than between output and only *some* of the factors. The multivariate approach reduces potentially omitted-variable biases.

Stern (2000) shows that there is cointegration in a relationship between GDP, capital, labor and energy, and that energy cannot be excluded from the cointegration space. One important characteristic in Stern (2000) is that cointegration vectors of output, capital, labor and energy are interpreted as production functions, and possibly as labor supply or capital acceleration functions. However, the author does not consider restrictions to the cointegration vectors, and hence the estimated coefficients do not sum to one and do not explicitly represent output elasticities.

More recently, Stresing, Lindenberger & Kümmel (2008) have tested for cointegration between output, capital, labor and energy for Germany, Japan and the US. The authors make a direct correspondence between cointegration coefficients and output elasticities of aggregate energy-dependent Cobb-Douglas production functions, and hence require these coefficients to meet certain assumptions (non-negative, summing to unity) in order to be economically meaningful. They find that the hypothesis of cointegration cannot be rejected for any country, the estimated output elasticities for labor (energy) being much smaller (larger) than the cost shares for these factors.

Unlike any of the works cited above, we adopt and compare between unadjusted and quality-adjusted measures for all factors of production, and not just energy. Within this framework, we test combinations of output and inputs to production for cointegration, and evaluate whether the observed vectors correspond to economically meaningful aggregate production functions.

We work, as Stresing, Lindenberger & Kümmel (2008), within a sub-space of economically meaningful cointegration vectors, which can be interpreted as Cobb-Douglas production functions, and whose normalized coefficients are the output elasticities for capital, labor and energy. Under our approach, we are much closer to a neoclassical framework for economic growth than Stern & Kander (2010), Kander & Stern (2014), or Kander, Malanima & Ward (2014). However, we still manage to reconcile the cost share theorem with the essential role of energy in production.

2 METHODOLOGY

We test the linear combinations of time series for output, capital, labor, and useful exergy for cointegration and Granger causality, following the Johansen approach (Johansen, 1998). Throughout the analysis, our working variables will be defined as the ratios of output, capital, and useful exergy per labor inputs (i.e. $Q/L, K/L, U/L$). Following the usual practice, we take natural logarithms of our variables, so the parameters may be interpreted as output elasticities (i.e. $q = log(Q/L), k = log(K/L), u = log(U/L)$).

There are three possible outcomes from cointegration analysis: a) no cointegration; b) at most one cointegration vector between all variables, which can be interpreted as a three-factor Cobb-Douglas production function, if it satisfies the necessary criteria (defined below); c) at most two cointegration vectors between the variables, which can be interpreted (again, if the defined criteria are satisfied) as a two-factor Cobb-Douglas production function (output as dependent variable), and a Cobb-Douglas type function (but not a production function) linking all variable inputs. For bivariate models, at most one cointegration vector (the production function) can be observed.

Estimated Cobb-Douglas production functions are compared in terms of goodness-of-fit and magnitude of TFP component to past economic growth Portugal, for the period between 1960 and 2009.

2.1 **Cointegration and Granger causality**

Prior to testing for cointegration, we test each time series individually for the presence of unit roots, applying the Augmented Dickey-Fuller (ADF) and Philips-Perron (PP) tests for non-stationarity. Working variables are grouped in vector autoregressive models (VAR). We will always group the output variable q with one or two input variables (k or u).

Tests for cointegration are conducted according to the multivariate Johansen procedure (Johansen, 1998). The Johansen test is applied here under the assumption of an unrestricted constant term in the VAR model but no linear trend in the cointegration vector. If the n time series included in any given VAR model are found to be cointegrated, the corresponding vector error-correction model (VECM) is given by:

$$\Delta\mathbf{Y}_t = \mathbf{c} + \alpha(\beta\mathbf{Y}_{t-1} + \mu) + \sum_{j=1}^{p} \Gamma_j \Delta\mathbf{Y}_{t-j} + \varepsilon_t \qquad (1)$$

Where $\mathbf{Y}_t$ is a $n \times 1$ vector of each model's time series, $\mathbf{c}$ is vector of constant terms, Γ_j represents matrices of short-run dynamics coefficients (lags), and ε_t is a vector of random disturbances. The term in parentheses in Equation (1) is the error-correction term (ECT), with β a $(n \times r)$ matrix of cointegration vectors (r being the number of cointegration vectors) and μ a vector of coefficients representing a constant in the cointegration space; α is a $(n \times r)$ matrix of adjustment coefficients. The ECT represent statistically significant long-term relationship between the variables in the VAR model $\mathbf{Y}_t$, which under certain conditions can be interpreted as an economically realistic production function.

In order to test the causal dynamics between the variables in a given model, we adopt the methodology developed by Engle & Granger (1987). Testing for Granger causality is preceded by the tests for cointegration, since the presence of cointegration vectors between the variables has implications for the way in which short and long-run causality is carried out. For a bivariate model case (q, k) with at most one cointegration vector between its variables, the corresponding VECM is

$$\begin{aligned} \Delta q_t &= c_1 + \alpha_1 ECT_{t-1} + \sum_{j=1}^{p} \varphi_{1j}\Delta q_{t-j} + \sum_{j=1}^{p} \theta_{1j}\Delta k_{t-j} \\ \Delta k_t &= c_2 + \alpha_2 ECT_{t-1} + \sum_{j=1}^{p} \varphi_{2j}\Delta q_{t-j} + \sum_{j=1}^{p} \theta_{2j}\Delta k_{t-j} \end{aligned} \qquad (2)$$

Where the normalized cointegration vector is $ECT_{t-1} = q_{t-1} + \left(\frac{\beta_2}{\beta_1}\right) k_{t-1} + \mu_1$. There are two sources of causation in Equation (2): the coefficients associated with the ECT, which provide evidence of an error-correction mechanism driving the variables back to their long-run relationship; and the coefficients on lagged terms, which indicate short-run dynamics.

Granger non-causality tests are applied by testing the statistical significance of coefficients. Short-run Granger non-causality tests are applied to lagged coefficients (e.g. testing the null hypothesis $H_0\colon \theta_{1j} = 0, \forall j$ using the Wald test), while long-run tests are applied to the

ECT adjustment coefficients. “Strong” long-run Granger non-causality is tested by examining whether the two sources of causation are jointly significant (e.g. testing the null hypothesis $H_0\colon \alpha_1 = \theta_{1j} = 0, \forall j$). In our analysis we consider only short-run causality and "strong" long-run causality relationships between variables.

2.2 Fits to real output and growth accounting

Comparison between real output and estimated output from production functions obtained via cointegration analysis are compared in terms of goodness-of-fit and magnitude of the TFP component in economic growth. The former is evaluated through comparison of root mean squared error (RMSE) in both levels and growth rates, while the latter is evaluated through growth accounting.

The fundamental equation for growth accounting can be expressed for two factors of production as:

$$g_Q = \alpha_K g_K + \alpha_L g_L + g_{TFP} \quad (3)$$

In equation (3), g_i stands for the growth rates of $i = Q, K, L$, and α_j for the marginal productivities of $j = K, L$; the growth rate of total factor productivity, g_{TFP} is determined as a residual, by subtracting the capital and labor contributions from total output growth. We adopt the observed annual factor shares corresponding to capital and labor (obtained from national accounts) as the values for α_K and α_L.

For cases where at most two simultaneous cointegration vectors are observed between pairs of variables in a given model, we algebraically manipulate both vectors to form a single long-term relationship between output, capital, and labor inputs (a two-factor production function of Cobb-Douglas type), and a second long-term relationship linking all three factors of production, which we use to estimate capital utilization as a function of useful exergy and labor inputs. Hence, for the case of at most two simultaneous cointegration vectors, the normalized ECT are:

$$\begin{cases} ECT_{1,t-1} = q_{t-1}\left(\frac{\beta_2}{\beta_1}\right)k_{t-1} + \mu_1 \\ ECT_{2,t-1} = k_{t-1}\left(\frac{\beta_4}{\beta_3}\right)u_{t-1} + \mu_2 \end{cases} \quad (4)$$

Where the first ECT is normalized with respect to q, and the second ECT normalized to k. Setting the ECT terms equal to zero, moving the normalized variable to the l.h.s., and multiplying both sides of Equation (4) by the labor inputs yields:

$$\begin{cases} Q = e^{\mu_1} K^{\alpha_K} L^{\alpha_L} \\ K = e^{\mu_2} U^{\gamma} L^{\delta} \end{cases} \quad (5)$$

With $\alpha_K = (-\beta_2/\beta_1)$ and $\alpha_L = 1 + (\beta_2/\beta_1)$ the output elasticities of the production function. We see that they must necessarily sum to one, and so this production function satisfies constant returns to scale. In the second equation in (5), we can write $\gamma = (-\beta_4/\beta_3)$ and $\delta = 1 + (\beta_4/\beta_3)$. Although these coefficients also sum to one, they are not interpreted as output elasticities and not subject to our production function criteria defined below, since this second function, although Cobb-Douglas in form, is not a production function (output is not the dependent variable).

Models where we observe two simultaneous cointegration vectors as in Equation (5) are tested for goodness-of-fit to real output and growth accounting considering two alternatives: a) using the observed time series for capital and labor inputs as dependent variables; b) estimating, using the second cointegration vector, a time series for capital inputs as a function of observed series for useful exergy and labor. This estimated series for capital is then substituted in the Cobb-Douglas function given by the first cointegration vector.

The reasoning for estimating capital (and not labor or useful exergy) from the other inputs using the second cointegration vector is as follows: when compared with both labor and energy (exergy) inputs, which are measured in physical units of hours worked and Joules, respectively, adopted monetary measures for capital inputs are the ones least successful in accurately representing the actual productive uses of these inputs in the economy. Even approaches to the measurement of the service flows of capital assets such as the ones adopted in our analysis rely on numerous assumptions on rates of return, depreciation of assets (in value and efficiency, by asset type), initial benchmarks of stocks of assets, and price variations. In comparison, our estimated measures for capital inputs depend uniquely on the physical measures for labor and useful exergy inputs.

2.3 Production function criteria

In this section we establish the criteria that will allow us to: 1) work within an economically realistic cointegration sub-space ("absolute" criteria); 2) select the estimated production function that best accounts for past economic growth in a given country ("relative" criteria).

The absolute production function criteria are defined as follows:

- There must be at least one cointegration relationship between output and inputs;
- Normalized cointegration coefficients must be non-negative and distinguishable from zero;

The relative criteria are defined as follows:

- Goodness-of-fit to real output levels and growth rates;
- Fraction of economic growth attributed to an exogenous residual;

2.3.3 Case-study: Portugal

Annual data is collected for 50 years, starting in 1960 and ending in 2009. We measure economic output (Q) as gross value added (GVA, from Pinheiro & Crespo (1997) and INE (2015)), corresponding to the sum of payments to the traditional inputs to production: capital (K) and labor (L). We will consider both unadjusted and quality-adjusted measures for both these factors (including several unadjusted measures for capital inputs, obtained from different sources, from AMECO (2015), PWT (2015), and da Silva & Lains (2013)). We also consider energy inputs to production, measured as the aggregate consumption of useful exergy (U), obtained from Serrenho et al., (2016).

We will be working with two measures for labor inputs (obtained from ????), and so we will produce two sets of variables, depending on whether these are defined by dividing output, capital and useful exergy by unadjusted labor inputs (indicated by a label L) or by quality-adjusted labor inputs (label hL). By performing econometric analysis with a wide variety of measures for factor inputs, we will be able to observe the effects of quality-adjusting for these inputs on our statistical estimates. For all cases, the models are defined in terms of both unadjusted and quality-adjusted labor inputs. Overall, our empirical analysis begins by considering two separate sets of 9 models each: 5 bivariate models and 4 multivariate models.

3.1 Unit roots tests

The ADF and PP unit root tests fail to reject the hypothesis of non-stationarity for all these time series in levels (for both unadjusted and quality-adjusted labor). Concerning the first differences of the time series defined per labor inputs, the non-stationarity hypothesis is always rejected by both tests at the 1\% significance level. We therefore conclude that all time series defined per labor inputs are integrated of first order, and hence we can conduct tests for cointegration between these variables.

3.2 Cointegration and Granger causality

All results corresponding to the cointegration and Granger causality tests conducted in our analysis are presented in Table (1). These results concern the above-defined absolute criteria for plausible Cobb-Douglas production functions.

Of the 18 models considered at the beginning of our analysis, only 7 satisfy all the absolute criteria. These are highlighted in Table (1). A total of 7 of the original 18 models are rejected due to no cointegration vectors being detected by the Johansen procedure. Of the remaining models, for which at least one cointegration vector is observed, 4 other models are rejected due to the normalized estimated coefficients falling outside the defined boundaries for a economically realistic Cobb-Douglas production function, (i.e. they assume negative values), or because the estimated normalized coefficients, while positive and bounded between 0 and 1, are not statistically significant (i.e. have large associated error terms).

We observe that none of the considered econometric models is rejected based solely on the absolute criteria of long-run Granger causality from inputs to output. All models show capital and useful exergy inputs (per labor) having a long-run causal effect on output (per labor). The one exception is the model $(q, k_{Services}^{S\&L})_{hL}$, for which no Granger causality relations are observed, but that also fails to satisfy the criterion of plausible economically realistic normalized cointegration coefficients.

We observe, for 3 of our econometric models, at most two cointegration vectors between the included variables. In these cases, one of the cointegration vectors connects output (q) with the useful exergy variable (u), while the other connects the capital (k and useful exergy u) variables. We normalize the first vector to output, and the second vector to capital inputs. Then, manipulating both vectors, we obtain: 1) a Cobb-Douglas production function formulation with output (Q) depending on capital (K) and labor (L, hL) inputs; 2) a Cobb-Douglas-like function where capital (K) is estimated from useful exergy (U) and labor (L, hL) inputs. For each of these models, both formulations are represented in Table (1).

Model	No. of CV	Normalized long-run relationships	Causal effects		Absolute production function criteria		
			Short-run	Long-run	Cointegration	Plausible output elasticities	Granger causality
$(q,u)_L$	≤ 1	$Q = e^{-7.772} \cdot U^{0.840} \cdot L^{0.160}$	$u \to q$	$u \to q$	Yes	Yes	Yes
$(q, k^{AMECO}_{Stock})_L$	≤ 1	$Q = e^{-8.188} \cdot K^{0.600} \cdot L^{0.400}$	-	$k \to q$	Yes	Yes	Yes
$(q, k^{PWT8.1}_{Stock})_L$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Stock})_L$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Services})_L$	0	-	-	-	No	-	-
$(q, k^{AMECO}_{Stock}, u)_L$	≤ 2	$\begin{cases} Q = e^{-4.794} \cdot K^{0.638} \cdot L^{0.362} \\ K = e^{-4.682} \cdot U^{1.313} \cdot L^{-0.313} \end{cases}$	$u \to q$ $u \to k$	$u \to q$ $u \leftrightarrow q$	Yes	Yes	Yes
$(q, k^{PWT8.1}_{Stock}, u)_L$	≤ 1	$Q = e^{-7.977} \cdot K^{0.073} \cdot L^{0.741} \cdot U^{0.186}$	$k \to q$ $u \to q$ $u \to k$	$k \to q$ $u \to q$ $u \to k$	Yes	No	Yes
$(q, k^{S\&L}_{Stock}, u)_L$	≤ 1	$Q = e^{-8.449} \cdot K^{-0.094} \cdot L^{0.902} \cdot U^{0.192}$	$u \to q$ $u \to k$	$k \to q$ $u \leftrightarrow q$ $u \leftrightarrow k$	Yes	No	Yes
$(q, k^{S\&L}_{Services}, u)_L$	≤ 2	$\begin{cases} Q = e^{-8.652} \cdot K^{0.374} \cdot L^{0.626} \\ K = e^{2.778} \cdot U^{2.344} \cdot L^{-1.344} \end{cases}$	$u \leftrightarrow q$	$k \to q$ $u \leftrightarrow q$	Yes	Yes	Yes
$(q,u)_{hL}$	≤ 1	$Q = e^{-8.194} \cdot U^{0.780} \cdot L^{0.220}$	-	$u \to q$	Yes	Yes	Yes
$(q, k^{AMECO}_{Stock})_{hL}$	≤ 1	$Q = e^{-7.115} \cdot K^{0.454} \cdot L^{0.546}$	-	$k \to q$	Yes	Yes	Yes
$(q, k^{PWT8.1}_{Stock})_{hL}$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Stock})_{hL}$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Services})_{hL}$	≤ 1	$Q = e^{-15.003} \cdot K^{-0.341} \cdot L^{1.341}$	-	-	Yes	No	No
$(q, k^{AMECO}_{Stock}, u)_{hL}$	≤ 1	$Q = e^{-7.977} \cdot K^{-0.522} \cdot L^{-0.043} \cdot U^{1.565}$	$u \leftrightarrow q$ $u \to k$	$k \to q$ $u \leftrightarrow q$ $u \leftrightarrow k$	Yes	No	Yes
$(q, k^{PWT8.1}_{Stock}, u)_{hL}$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Stock}, u)_{hL}$	0	-	-	-	No	-	-
$(q, k^{S\&L}_{Services}, u)_{hL}$	≤ 2	$\begin{cases} Q = e^{-9.651} \cdot K^{0.308} \cdot L^{0.692} \\ K = e^{7.694} \cdot U^{3.111} \cdot L^{-2.111} \end{cases}$	$u \to q$	$k \to q$ $u \leftrightarrow q$	Yes	Yes	Yes

Table 1: **Production function criteria - results from cointegration analysis and Granger causality tests.** Top half shows models defined per unadjusted labor inputs (L). Bottom half shows models defined per quality-adjusted labor inputs (hL). Column (1) specifies the model; columns (2) and (3) present the number and normalized form of observed cointegration vectors; columns (4) and (5) present short and long-run Granger causality (arrows represent the direction of causality); columns (6-8) indicate whether the model satisfies the criteria of existence of cointegrating relationship (6), plausible output elasticities (7), and causal effect from inputs to output (8). Models that satisfy every criteria are highlighted.

The econometric models shown in Table (1) are further tested according to our relative criteria for adjustment of production functions to the Portuguese economy in the past 50 years.

3.3 Fits to real output and growth accounting

The estimated production functions obtained from the econometric models in Table (1) are compared in terms of their goodness-of-fit to real output levels and annual growth rates of the

Portuguese economy (1960-2009), as well as in terms of the magnitude of the estimated TFP component in output growth. In the former case, the comparison is made through RMSE estimates, and in the latter case it results from growth accounting exercises. A graphical representation of each fit to output levels, obtained with the 7 models that satisfy all or the absolute production function criteria, is shown in Figure (1).

Model/Data	Estimated production function	Estimated factor	RMSE (level)	RMSE (growth)	Output growth (%)	$\alpha_K g_K$ (%)	$\alpha_L g_L$ (%)	Residual (%)
$(q,u)_L$	$Q=e^{-7.772}.U^{0.840}.L^{0.160}$	None	0.051	0.031	-	-	-	-
$(q,k_{Stock}^{AMECO})_L$	$Q=e^{-5.188}.K^{0.600}.L^{0.400}$	None	0.167	0.035	3.45	1.04	0.32	2.08
$(q,k_{Stock}^{PWT8.1})_L$	-	None	-	-	3.45	1.44	0.32	1.68
$(q,k_{Stock}^{S\&L})_L$	-	None	-	-	3.45	1.19	0.32	1.94
$(q,k_{Services}^{S\&L})_L$	-	None	-	-	3.45	1.45	0.32	1.67
$(q,k_{Stock}^{AMECO},u)_L$	$Q=e^{-4.794}.K^{0.638}.L^{0.362}$	None	0.152	0.035	3.45	1.04	0.32	2.08
		$K(U,L)$	0.052	0.031	3.45	1.33	0.32	1.80
$(q,k_{Stock}^{PWT8.1},u)_L$	$Q=e^{-7.911}.K^{0.073}.L^{0.741}.U^{0.186}$	None	2.508	0.038	-	-	-	-
$(q,k_{Stock}^{S\&L},u)_L$	$Q=e^{-8.449}.K^{-0.094}.L^{0.902}.U^{0.192}$	None	2.996	0.044	-	-	-	-
$(q,k_{Services}^{S\&L},u)_L$	$Q=e^{-8.652}.K^{0.374}.L^{0.626}$	None	0.206	0.035	3.45	1.45	0.32	1.67
		$K(U,L)$	0.040	0.031	3.45	2.30	0.32	0.82
$(q,u)_{hL}$	$Q=e^{-8.194}.U^{0.780}.L^{0.220}$	None	0.048	0.030	-	-	-	-
$(q,k_{Stock}^{AMECO})_{hL}$	$Q=e^{-7.115}.K^{0.454}.L^{0.546}$	None	0.150	0.035	3.45	1.04	1.04	1.36
$(q,k_{Stock}^{PWT8.1})_{hL}$	-	None	-	-	3.45	1.44	1.04	0.96
$(q,k_{Stock}^{S\&L})_{hL}$	-	None	-	-	3.45	1.19	1.04	1.22
$(q,k_{Services}^{S\&L})_{hL}$	$Q=e^{-15.003}.K^{-0.341}.L^{1.341}$	None	0.438	0.052	3.45	1.45	1.04	0.95
$(q,k_{Stock}^{AMECO},u)_{hL}$	$Q=e^{-7.977}.K^{-0.522}.L^{-0.043}.U^{1.565}$	None	2.023	0.044	-	-	-	-
$(q,k_{Stock}^{PWT8.1},u)_{hL}$	-	None	-	-	-	-	-	-
$(q,k_{Stock}^{S\&L},u)_{hL}$	-	None	-	-	-	-	-	-
$(q,k_{Services}^{S\&L},u)_{hL}$	$Q=e^{-9.651}.K^{0.308}.L^{0.692}$	None	0.144	0.033	3.45	1.45	1.04	0.95
		$K(U,L)$	0.040	0.032	3.45	2.37	1.04	0.03

Table 2: **Fits to real output levels and output growth for the Portuguese economy - results from Root Mean Squared Error (RMSE) and growth accounting.** Top half shows models defined per unadjusted labor inputs (L). Bottom half shows models defined per quality-adjusted labor inputs (hL). Column (1) specifies the model; columns (2) and (3) present the production function formulation and whether any of the factor inputs is estimated from the other inputs (e.g. K as a function of U and L); columns (4) and (5) show the RMSE estimates for real output levels (4) and annual growth rates (5); columns (6-9) refer to the growth accounting exercises, subtracting from average output growth (6) the contributions from capital (7) and labor (8) inputs, to obtain a residual component (9). Growth accounting is performed assuming observed factor shares and not estimated output elasticities. Models that satisfy the absolute production function criteria defined earlier are highlighted.

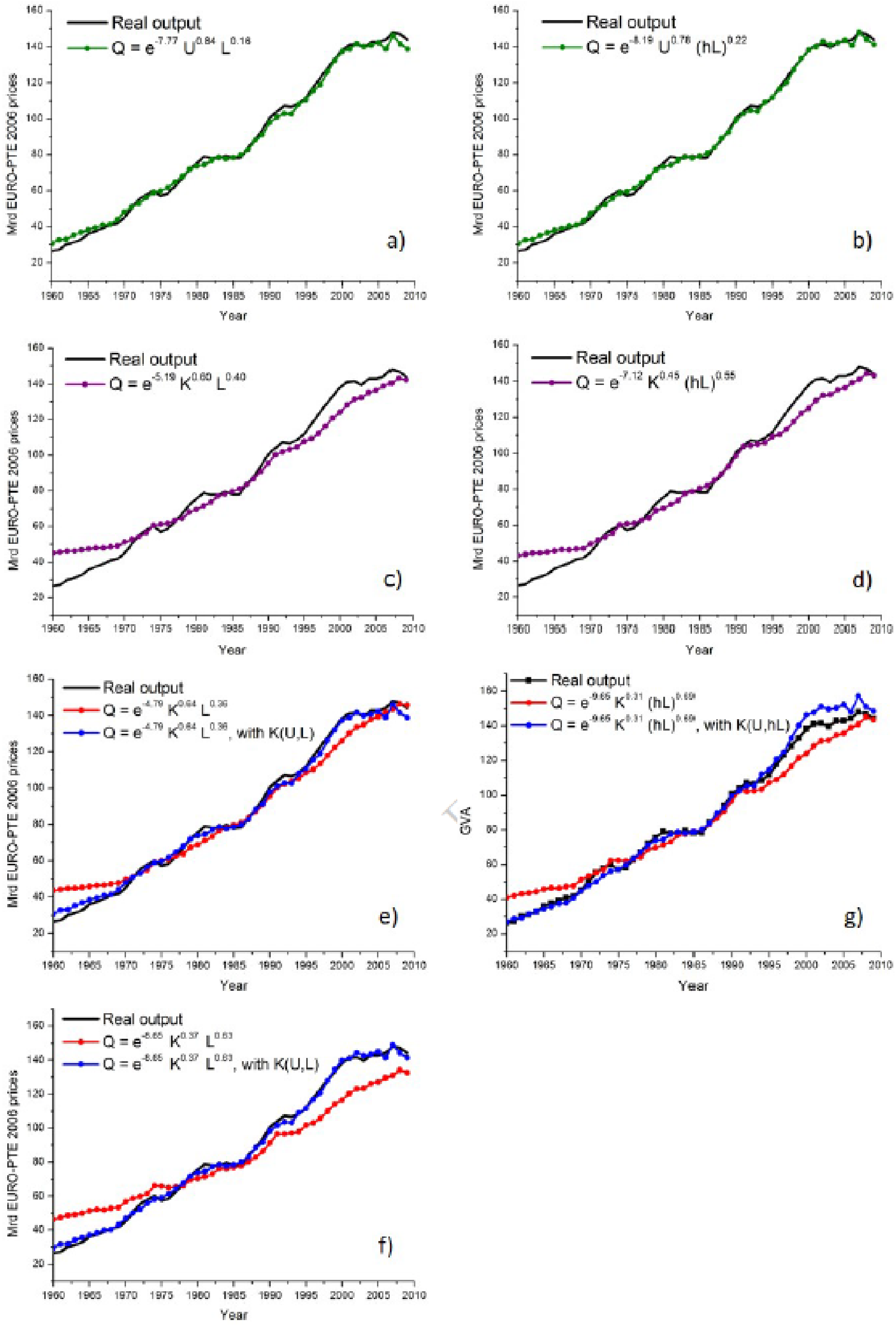

Figure 1 - Fits to real output levels for estimated production function obtained with models satisfying all absolute production function criteria. Left: Estimated production functions with unadjusted labor input. Right: Estimated production functions with quality-adjusted labor inputs. a)-b) Estimated p.f. for bivariate models with useful exergy and labor inputs; c)-d) Estimated p.f. for bivariate models with AMECO capital stock and labor inputs; e)-g) Estimated p.f. for multivariate models with AMECO capital stocks (e), or da Silva & Lains (2013) capital services (f, g), and labor inputs. Estimated p.f. for multivariate models are represented assuming observed capital inputs (red) and capital inputs estimated as a function of useful exergy and labor inputs (blue).

In terms of fits to observed levels and growth rates of output for the Portuguese economy, the lowest RMSE are obtained with estimated production functions that either: 1) have a useful exergy-labor form (no capital inputs); 2) have a capital-labor form, but capital is estimated as a function of useful exergy and labor, through a second cointegration vector. The former results are not unexpected, given that useful exergy by itself tracks Portuguese output very closely.

The TFP component for model $(q, k^{S\&L}_{Services}, u)_{hL}$ is the smallest reported: less than 1\% of unexplained overall output growth for the Portuguese economy between 1960-2009. In comparison, the largest obtained TFP component, which corresponds to model $(q, k^{AMECO}_{Stock}, u)_{L}$, accounts for more than 60\% of overall output growth.

The absolute worse fits to real output levels or growth rates are obtained with the few estimated production functions where useful exergy appears as an independent variable, alongside capital and labor. Introducing energy inputs as an additional independent variable in the standard production function, by itself does not guarantee a better fit to past economic growth. It is only when useful exergy either substitutes, or is an estimator of, capital inputs that there is a significant impact in terms of goodness-of-fit.

While it can be argued that introducing more variables will *per se* result in a better fit of the model to observed data, it should be noted that the two-factor useful exergy-labor production functions obtained with bivariate models including only output and useful exergy (per labor inputs) already produce very good fits. The inclusion of a capital variable serves the purpose of having a production function formulation with the traditional factors of production, as used in the neoclassical approach, and obtain information on the payments to these factors of production, assuming that the cost-share theorem holds.

The best results are obtained with model $(q, k^{S\&L}_{Services}, u)_{hL}$, the only model that combines: a) inclusion of capital services and useful exergy in the cointegration space; b) variables defined per quality-adjusted labor inputs; c) real capital utilization estimated as a function of useful exergy and labor. The estimated cointegration coefficients for this model, corresponding to output elasticities ($\hat{\alpha}_K = 30.8\%$ and $\hat{\alpha}_L = 69.2\%$) can be compared to observed cost shares associated with capital in labor in national accounts. In this graph it can be seen that, while the first decades are marked by strong variation of income shares, overall they will average to values of $\alpha_K = 29.5\%$ for capital inputs and $\alpha_L = 70.5\%$ for labor inputs.

Within the estimated $(q, k^{S\&L}_{Services}, u)_{hL}$ model, we can observe both the essenciality of energy inputs, through the estimation of capital inputs, and neoclassical assumptions, through a correspondence with the cost-share theorem.

4 CONCLUSIONS

We have examined the cointegration relationships between combinations of output and factor inputs for Portugal, in the last 50 years. Under the appropriate criteria, these relationships can be interpreted as economically realistic Cobb-Douglas production functions.

The main conclusion is that for our case-study, in contrast with the literature, the argument of energy essentiality in production from ecological economics is not *a priori* incompatible with the neoclassical assumptions of the “cost-share theorem”. Namely, we find that the best estimated fits to past economic trends (and lowest TFP) in Portugal are obtained with an estimated production function obtained with econometric model where there are two simultaneous cointegration vectors, which can be written as: 1) one linking all factor inputs, and through which capital utilization can be estimated as a function of useful exergy and labor inputs; 2) one linking output, capital and labor inputs, which has the form of a two-factor Cobb-Douglas production function.

The corresponding model is estimated by including quality-adjusted measures of capital (services), labor (human-capital adjusted), and energy (useful exergy) inputs in the cointegration space, alongside output. The first cointegration vector gives us the estimated constant output elasticities for capital and labor, which are very similar to the average values for the observed cost-shares for Portugal in the last 50 years. The second cointegrating vector allows us to obtain a better estimate for the utilization of capital than what is provided by either the stock of assets or the flow of services. In this estimate, productive capital is a function of useful exergy consumption and quality-adjusted labor inputs.

Useful exergy inputs do not appear explicitly in the estimated production function, but they have a major role in explaining economic output: they form an accurate proxy for capital utilization in production because capital assets are useless without being activated by useful exergy. Payments to useful exergy inputs are therefore implicit in the share of payments to capital. Since energy inputs do not appear explicitly in the estimated Cobb-Douglas function, their cost-share is zero, as in the neoclassical two-factor approach. However, as defended by ecological economics, energy has a major role in explaining economic output; it is an accurate proxy for real capital utilization because capital is useless without being activated by energy.

Comparing between econometric models, we find that adjusting for qualitative differences between capital and labor *ceteris paribus* has a marginal effect on the goodness-of-fit to past economic growth for estimated production functions, and some positive effect in reducing TFP. However, when capital inputs are estimated from observed useful exergy and labor inputs, the goodness-of-fits increase very significantly. This suggests that despite adjusting for the quality of capital inputs by accounting for the services provided by the stocks of assets, it is only by accounting for the exergy consumed in devices and machines and used productively in the economy that one can accurately estimate the real utilization of capital in production.

Overall, the best fits to past Portuguese economic output are obtained when capital inputs are either excluded from the cointegration space (q, u), or are estimated from useful exergy and labor inputs. In contrast, the worst fits obtained in our analysis all refer to estimated production functions obtained from models where energy is absent from the cointegration space (q, k). These functions are the ones which most resemble the standard neoclassical Cobb-Douglas fitting procedures.

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The economic and environmental efficiency assessment in EU cross- country

Mara Madaleno[1,2], Victor Moutinho[3], Margarita Alves [1,4]

[1] *GOVCOPP - Research Unit in Governance, Competitiveness and Public Policy, and Department of Economics, Management and Industrial Engineering, University of Aveiro, Campus de Santiago, 3810-193, Aveiro, Portugal,*
[2] *Corresponding author; email: mmadaleno@ua.pt*
[3]*CEFAGE – Center of Advanced Studies in Management and Economics, University of Évora, University of Aveiro, Campus de Santiago, 3810-193, Aveiro, Portugal, email: vmoutinho@ua.pt*
[4]*email:mrobaina@ua.pt*

ABSTRACT

This article aims to estimate the efficiency of 26 different European Countries over 2001 and 2012 comparing their performance and to contribute to their improvement of economic and environmental performance. Data Envelopment Analysis technique (DEA) is used to evaluate the performance of each European country. The output-oriented model was used with two specifications (Variable and Constant Returns to Scale) including Output ratio and Inputs ratio, such as, inputs labor and capital productivity, the weight of fossil energy and the share of renewable energy in GDP (gross domestic product), being the output GDP per GHG (greenhouse gases) emissions. Our results show that the economic and environmental estimates using the DEA estimation techniques for these European countries changes in energy sources. Thus, capital and labor ratios might give a reasonable simultaneous indication of the economic and environmental efficiency improvements.

KEYWORDS: Eco-Efficiency, European Countries, Taxation, DEA

1 INTRODUCTION

Eco-efficiency main goals are to increase the value of a good or service, optimize resources use and to reduce environmental impacts. It was defined by OECD (1998) as “the efficiency with which ecological resources are used to meet human needs” and by Picazo-Tadeo et al. (2011) as “the ability of firms, industries or economies to produce goods and services while incurring less impact on the environment and consuming fewer natural resources”. Robaina-Alves et al. (2015) study the eco-efficiency problem of 27 European countries in two distinct periods (2000-2004 and 2005-2011) to account for the Kyoto Protocol in 2005. The authors specified a new stochastic frontier model where the ratio between GDP and GHG emissions is maximized given the values of fossil fuel consumption, renewable energy consumption, capital and labor as inputs. Their empirical results show the most efficient countries (Portugal, Slovakia, Hungary and Ireland) and the least efficient ones (Bulgaria, Italy, Romania and Denmark) and they noticed that there has been a great effort by some countries in the second period of the analysis to converge to the efficiency frontier. Countries that are more eco-efficient, like Sweden, Cyprus, Latvia and UK are countries for which GDP grew at more moderate rates (on average between -1% and 2%).

In this work we try to evaluate the resource and environment efficiency or eco-efficiency problem of 26 European countries as Robaina-Alves et al. (2015) do, but instead of using absolute values, for ranking establishment we use ratios. Instead of only establishing a ranking in terms of levels of eco-efficiency differences is that we try to explain through several variables the ranking differences (namely, fiscal, production and domestic material consumption variables). A final difference respects to the way estimations are to be performed. Similar to Robaina-Alves et al. (2015) technical efficiency was estimated and the maximized output is the GDP/GHG ratio. Thus, the estimation of technical efficiency is also a measure of eco-efficiency, just by replacing CO2 by a composite good of environmental pressures (GHG as do Schmidheiny and Zorraquin, 1996).

For support the environmental policymaking in Europe it is necessary to have indicators of economic and environmental efficiency, to compare the evolution of ECO-efficiency among countries or sectors, set goals and to simultaneously implement effective environmental taxation policies (whose aim is to justify the level of differences in goal commitment harmonization of environmental taxation policy in the EU). These propose justify why it is very important to consider simultaneously in the analysis the energy and non-energy resources productivity in energy and environmental efficiency.

The present article uses the non-parametric Data Envelopment Analysis (DEA) which has been extensively used in the empirical literature at the macro level operation management performance evaluation as well as a solution to solve and evaluate the level of productivity in panel European countries. So, we will use the solutions of the linear programming problem in order to identify efficiency scores and ranking the countries evaluation position. Basically, we initially aim to evaluate resource and environment efficiency (Eco-efficiency) problem of European countries according to the output variable and some inputs following Robaina-Alves et al. (2015).

In addition, we use the particular period 2001-2012, before and after Kyoto commitment, to understand major changes in location strategies in both energy and energy intensity sectors which are more important to be considered by environmental policies, turning questionable if GDP, GHG emissions, fossil fuel consumption, renewable energy consumption, capital and labor as a key determinant of different efficiency levels among European countries.

The article is composed of five sections. After this introduction, section 2 covers the literature review, while the methodology used in this article is presented in section 3. Results and their respective discussion are presented in section 4 and finally, conclusions are presented in section 5.

2 LITERATURE REVIEW

Eco-efficiency of countries and/or economic sectors have already been assessed through DEA techniques. Picazo-Tadeo and Prior (2009) use DEA and directional distance functions to conclude that intensive technology economic activities can diminish environmental damages without compromising output maximization. More recently, Avadí et al. (2014) use a combination of life cycle assessment (LCA) and DEA to examine the eco-efficiency in 13 fleet segments of fishing vessels and Zhu et al. (2014) applied the same combined methodology to compare the eco-efficiency of 10 pesticides. Allowing for dynamic effects and using panel data (DEA window analysis – Charnes and Cooper, 1985), Halkos and Tzeremes (2009) calculate the eco-efficiency for 17 OECD countries constructing an efficiency ratio also used by Zaim (2004). Other authors study eco-efficiency it at the sectoral level. Picazo-Tadeo et al. (2011, 2012) analyze eco-efficiency in the agricultural sector. Previously, Barba-Gutierrez et al. (2009) use LCA to compare eco-efficiency of different household electric appliances using their environmental impact. More recently, Egilmez et al. (2013) use economic input-output life cycle assessment and DEA to measure eco-efficiency in US manufacturing sectors.

Robaina-Alves et al. (2015) specify a new stochastic frontier model considering GDP as the desirable output and GHG emissions as the undesirable output using capital, labor, fossil fuels and renewable energy consumption as inputs, maximizing the GDP/GHG ratio. They use a new maximum entropy approach to assess technical efficiency combining information from DEA and the structure of composed error from the stochastic frontier approach. The authors conclude for the 26 European countries used into their study that the most efficient ones were Portugal, Slovakia, Hungary and Ireland and the least efficient Bulgaria, Italy, Romania and Denmark. Filipovic and Golusin (2015) analyze the existing way of measuring financial effects of environmental taxation in EU27. In the European Union (EU), environmental policy and environmental taxation are regulated by EU laws and not by individual member countries legislations (Masstricht Treaty, 1992). There are strong theoretical arguments showing that environmental taxes make existing tax distortions worse (Uddin and Holtedahl, 2013) and it is rarely possible to identify the appropriate tax rates to internalize externalities (Golusin et al., 2013). As such, monitoring and auditing are regarded as essential activities for process control and follow up, thus contributing to performance improvements and useful in preventing or reducing environmental harms (Mironeasa and Codina, 2013).
Among the factors that determine resource use and productivity, we may include climate, population density, infrastructure needs, domestic availability of raw materials versus reliance on imports, prevailing fuel in the power generation sector, the rate of economic growth, technological development, and the structure of the economy (EEA's report SOE, 2015). The long-term objective of current European environmental policies is that the overall environmental impact of all major sectors of the economy should be significantly reduced, and resource efficiency increased. The large differences in resource-efficiency performance amongst countries and the fact that the same half-a-dozen countries have remained at the bottom of resource efficiency rankings since 2000 — indicates opportunities for improvements and actions (EEA's report SOE, 2015). Natural resources underpin economic and social development, and over-consumption of these resources has resulted in environmental degradation and economic losses. Improving the resource efficiency of European economies and societies is essential, and this objective has been on the European environmental policy agenda for more than a decade (EC, 2005, 2008, 2011). As Zhou et al. (2014) state, for instance, a productive entity may have more than one abatement strategies and different groups of productive entities may face different degrees of environmental regulations. In addition, since the marginal abatement cost for a productive entity is dependent upon its abatement level, the derivation of a curve for shadow prices would provide valuable approximation to marginal abatement cost curve. As such, there could be differences with respect to taxation, resources productivity or even DMC able to explain the eco-efficiency ranking among European countries which we will try to analyze.

3 DATA AND METHODOLOGY

Data for the period 2001-2012 has been collected for 26 European countries: Belgium, Bulgaria, Czech Republic, Denmark, Germany, Estonia, Ireland, Greece, Spain, France, Italy, Cyprus, Latvia, Lithuania, Luxembourg, Hungary, Netherlands, Austria, Poland, Portugal, Romania, Slovenia, Slovakia, Finland, Sweden and United Kingdom. The inputs labor productivity, capital productivity, the weight of fossil energy and the share of renewable energy in GDP were used, considering the output ratio GDP per GHG emissions in a first phase. Using these variables, technical efficiency was computed and a countries ranking was established. Contrary to Robaina-Alves et al. (2015) we use input ratios instead of levels but the same output.

The Gross Domestic Product (GDP) by country was collected from Eurostat at market and constant prices of the year 2000 in millions of euro. Greenhouse Gas Emissions (GHG) or CO2 equivalent was collected in thousands of tones from the European Environment Agency. Fossil fuel consumption is the sum of final energy consumption of solid fuels, gas and petroleum products measures in thousands of tons of oil equivalent (TOE) and taken from Eurostat. The weight of fossil fuel is computed over total energy produced. Renewable energy consumption is the final energy consumption of renewable and wastes in thousands of TOE also taken from Eurostat and renewable energy share was computed considering GDP. Labor productivity per hour worked is calculated as real output (deflated GDP measured in chain-linked volumes, reference year 2005) per unit of labor input (measured by the total number of hours worked)[1].

Capital productivity is calculated as real output (deflated GDP measured in chain-linked volumes, reference year 2005) per unit of capital input (measured by the gross fixed capital formation at constant prices of the year 2000, in Millions of euro. Both productivity measures were taken from Eurostat. The GDP/GHG ratio is used as output and the other four ratios as inputs by using a log-linear Cobb-Douglas production function.

There exist two main models to compute the data envelopment analysis (DEA) index. On one hand we have the Charnes-Cooper-Rhodes (CCR) which is a constant returns-to-scale model (Charnes et al., 1978) and on the other hand we have the Banker-Charnes-Cooper (BCC) which is a variable returns-to-scale model (Cooper et al., 2007). The main advantage of considering variable returns is that these allow capturing in part the heterogeneity among countries. Both developed models generate a piecewise-linear envelopment surface and are simultaneously input-or-output oriented, only depending if our goal is to maximize input contraction or output expansion, with output production or input consumption, respectively, kept constant. They yield identical envelopment or convex surfaces but are different in the way inefficient decision making units (DMUs) are projected onto the efficient frontier (Cooper et al., 2007). A DMU is responsible for converting multiple inputs into multiple outputs and whose efficiency[2] is to be evaluated (Cooper et al., 2007).

Besides the input-oriented model, usually referred to as CRS-DEA, introduced by Charnes et al. (1978), which is going to be used, we also use the BCC or VRS model, meaning its variable version (Cooper et al., 2007). In the CRS-DEA model constant returns to scale are assumed to exist imposing that the set of production possibilities is formed with no scale effect. Usually, technical efficiency represents the success of a DMU which produces at its maximum output

[1] As stated in Eurostat (http://ec.europa.eu/eurostat/tgm/table.do?tab=table&init=1&language=en&pcode=tsdec310&plugin=1) measuring labor productivity per hour worked provides a better picture of productivity developments in the economy than labor productivity per person employed, as it eliminates differences in the full time/part time composition of the workforce across countries and years.

[2] Efficiency refers to the relationship between inputs and outputs. It can be improved by consuming fewer inputs while maintaining the same output level. When the optimal weighting of outputs and inputs for a country yields an efficient ratio of one, the country is considered efficient, but when it is less than one the country is inefficient. When considered in percentage terms a value like 0.74 of efficiency ratio means that a country is 74% efficient or 26% inefficient.

when a specific group of inputs is used, being inputs exogenous and outputs endogenous. The CRS model of efficiency is probably one of the most used and known within DEA models.
Later on, Banker et al. (1984) raised the optimization problem considering variable returns-to-scale (VRS) where the efficiency of a DMU depends over the size and the effect of resources increasing becomes different across the DMUs. This relationship became known as the pure technical efficiency being a measure of the transformation process of resources into outputs.
The BCC model major advantage is the fact that units with scale inefficiency are only compared with efficient units with a similar dimension.
The technical efficiency index is known as technical efficiency (TE), which is basically a measure by which the performance of some DMUs are evaluated *vis-à-vis* the performance of other DMUs. This measure is also called global efficiency and can be computed by the following expression:

$$TE_k = \frac{v_1 y_{1k} + v_2 y_{2k} + v_3 y_{3k} + \ldots + v_m y_{mk}}{\varpi_1 x_{1k} + \varpi_2 x_{2k} + \varpi_3 x_{3k} + \ldots + \varpi_n x_{3nk}} = \frac{\sum_{p=1}^{k} v_p y_{pk}}{\sum_{q=1}^{k} \varpi_q y_{qk}} \tag{1}$$

where TE is the technical efficiency measure given to the k unit;; p is the number of inputs (p = 1; 2; …, m); q is the number of outputs ($q = 1,2,,..,n$) and k represents the k_{th} DMU ($k = 1,2,,..,j$)., x and y represent inputs and outputs v and ϖ represent the inputs and outputs weights. Equation (1) can be expressed as a linear programming problem stated as:

$$\max \theta = \sum_{p=1}^{k} v_p y_{pk} \tag{2}$$

subject to the following set of restrictions:

$$\begin{cases} (i) \sum_{q=1}^{k} \varpi_q y_{qk} x_n = 1, \ i = 1,2,3,\ldots,k \\ (ii) \sum_{p=1}^{k} v_p y_{pk} - \sum_{q=1}^{k} \varpi_q y_{qk} x_n \leq 0 \\ (iii) v_p \geq 0, p = 1,2,3,\ldots,m \\ (iv) \varpi_q \geq 0, q = 1,2,3,\ldots,n \end{cases} \tag{3}$$

in which θ is the technical efficiency parameter. In this article the input-oriented model, usually referred to as CCR-DEA, introduced by Charnes et al. (1978), is going to be used. In this model the existence of constant returns to scale is assumed under the condition that the set of production possibilities is formed without any scale effect.

Afterwards, Banker et al. (1984) formulate the problem of optimizing the variable returns scale (VRS), where the efficiency of a DMU depends on the size of the companies, where the effect of increasing the resources will be different across the DMUs. This relationship is known as the pure technical efficiency and it is a measurement of the transformation process of resources into outputs. The BCC model can be described by a dual problem of linear programming, expressed by the following objective function:

$$\max \mathrm{Z} = v y_i - v_i \tag{4}$$

subject to the following set of restrictions:

$$\begin{cases} (i)\varpi x_i = 1, \\ (ii) - \varpi\ Y + \nu X - \nu_0 \varepsilon \le 0 \\ (iii)\varpi \ge 0, \nu \ge 0 \wedge \nu_0 \end{cases} \tag{5}$$

where ν_0 is unrestricted in sign, where z and ν_0 are scalar, ϖ and ν are outputs and matrices of the weight of inputs, and Y and X are the correspondent outputs and matrices of inputs, respectively. y_i and x refer to inputs and outputs of a DMU. The main advantages of the BCC model is that the units with scale inefficiency are only compared with efficient units with a similar dimension. DEA efficiency score is given by a specific ν value, between 0 and 1. Here 1 indicates that a DMU shows the best performance localized in the production frontier and reveals no potential reduction. Any ν lower than 1 indicates that the DMU uses inputs inefficiently. Both CRS and VRS model versions are estimated through DEA.

4 EMPIRICAL RESULTS

This section starts by presenting the eco-efficiency scores obtained through the output-input maximization first procedure explained above. As it was previously said the closer the value of eco-efficiency (EE) is from unit, the more efficient the country is, which means that the country is making the best use of economic and energy resources to produce the maximum possible output (GDP) and at the same time is minimizing the environmental impact through GHG emissions.

Table 1 - Eco-Efficiency in European Countries – Output Oriented –Variable Return Scale

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Austria	0.824	0.748	0.812	0.827	0.852	0.862	0.897	0.937	0.896	0.878	0.877	0.802
Belgium	0.796	0.863	0.847	0.857	0.837	0.816	0.808	0.858	0.830	0.837	0.783	0.767
Bulgaria	0.853	0.866	0.842	0.800	0.815	0.758	0.715	0.681	0.493	0.548	0.565	0.570
Cyprus	0.912	0.919	0.927	0.930	0.936	0.946	0.956	1.000	0.956	0.889	0.852	0.945
Czech Republic	0.551	0.656	0.563	0.573	0.596	0.582	0.571	0.502	0.474	0.535	0.498	0.460
Denmark	0.816	0.841	0.822	0.788	0.832	0.841	0.632	0.645	0.722	0.799	0.800	0.755
Estonia	0.541	0.613	0.489	0.422	0.439	0.412	0.356	0.296	0.345	0.500	0.401	0.336
Finland	0.739	0.814	0.767	0.722	0.761	0.835	0.701	0.687	0.754	0.731	0.694	0.703
France	0.895	0.896	0.896	0.896	0.897	0.882	0.895	0.888	0.835	0.876	0.886	0.806
Germany	0.560	0.818	0.792	0.789	0.791	0.790	0.730	0.690	0.676	0.744	0.724	0.613
Greece	0.686	0.757	0.667	0.639	0.659	0.677	0.606	0.491	0.588	0.651	0.672	0.705
Hungary	0.771	0.859	0.838	0.847	0.870	0.898	0.967	1.000	0.940	0.898	0.884	0.978
Ireland	0.642	0.736	0.727	0.698	0.692	0.624	0.612	0.661	0.700	0.830	0.949	0.989
Italy	0.817	0.854	0.827	0.817	0.796	0.795	0.766	0.786	0.755	0.827	0.793	0.725
Latvia	0.895	0.894	0.914	0.914	0.915	0.895	0.874	0.902	0.995	0.967	0.977	0.989
Lithuania	0.881	0.874	0.879	0.862	0.851	0.857	0.791	0.650	0.690	0.893	0.826	0.736
Luxembourg	0.878	0.885	0.857	0.846	0.851	0.857	0.858	0.969	0.901	0.876	0.799	0.690
Netherlands	0.867	0.862	0.878	0.869	0.886	0.899	0.899	0.908	0.843	0.898	0.910	0.793
Poland	0.655	0.804	0.729	0.741	0.740	0.742	0.689	0.639	0.553	0.595	0.548	0.493

Portugal	0.753	0.791	0.790	0.831	0.844	0.825	0.868	0.861	0.825	0.841	0.883	0.933
Romania	0.902	0.917	0.890	0.877	0.904	0.911	0.910	0.790	0.608	0.791	0.691	0.716
Slovakia	0.780	0.758	0.796	0.827	0.801	0.822	0.813	0.859	0.840	0.899	0.831	0.707
Slovenia	0.791	0.820	0.821	0.818	0.839	0.843	0.801	0.792	0.768	0.833	0.878	0.946
Spain	0.769	0.791	0.710	0.690	0.686	0.632	0.572	0.561	0.589	0.691	0.757	0.699
Sweden	0.953	0.935	0.958	0.960	0.965	0.969	0.978	1.000	1.000	0.959	0.960	0.981
United Kingdom	0.913	0.900	0.922	0.917	0.901	0.924	0.935	0.975	0.997	0.956	0.966	0.965

In the first estimation (variable returns-to-scale) according to Table 1, the empirical evidence shows that in 2012 Ireland, Latvia, Sweden, Hungary and United Kingdom are the five most efficient countries, while Estonia, Czech Republic, Poland, Bulgaria and Germany constitute the five least efficient countries. In 2012 both Ireland and Latvia were 98.9% efficient and 1.1% inefficient. Comparing our results to those of Robaina-Alves et al. (2015) we see that even using different estimators and different inputs (ratios were considered here) there has been some effort done by countries to converge to the efficiency frontier (especially in Hungary, Austria and Latvia). For the first four positions as the most efficient ones: Ireland, Latvia, Sweden and Hungary and four the last four positions (the least efficient): Bulgaria, Poland, Czech Republic and Estonia. As such, despite the fact that results point for the importance of the share of renewables and non-renewable energy sources being important to explain differences in emissions, the way inputs are considered into the maximization problem in terms of eco-efficiency ranking establishment and the way it is computed is also important.

Turning again to the evidence presented in both Table 1 we may state that Ireland, Hungary and Portugal are becoming relatively more efficient, while Bulgaria, Luxembourg and Romania became the least economic and environmental efficient countries in the entire period analysed. Next, in Table 3 we present the same eco-efficiency values obtained through DEA but considering CRS, where at a first analysis we may state that having VRS or CRS considered changes results in terms of ranking positions (see Tables 1 and 2, for comparison).

Table 2 - Eco-Efficiency in European Countries – Output Oriented –Constant Returns-to-Scale

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Austria	0.675	0.741	0.746	0.737	0.752	0.749	0.752	0.769	0.758	0.761	0.755	0.737
Belgium	0.714	0.728	0.720	0.730	0.703	0.681	0.690	0.693	0.683	0.692	0.679	0.660
Bulgaria	0.746	0.723	0.714	0.693	0.693	0.657	0.644	0.646	0.585	0.593	0.593	0.581
Cyprus	0.778	0.832	0.801	0.810	0.799	0.777	0.772	0.798	0.755	0.755	0.720	0.744
Czech Republic	0.512	0.578	0.548	0.566	0.583	0.586	0.580	0.602	0.538	0.544	0.511	0.485
Denmark	0.691	0.718	0.717	0.698	0.733	0.748	0.688	0.698	0.684	0.711	0.698	0.665
Estonia	0.484	0.540	0.484	0.454	0.484	0.485	0.476	0.454	0.459	0.532	0.484	0.410
Finland	0.629	0.698	0.690	0.664	0.696	0.703	0.687	0.679	0.673	0.667	0.657	0.666
France	0.743	0.777	0.762	0.774	0.783	0.774	0.789	0.776	0.712	0.716	0.703	0.728
Germany	0.652	0.694	0.674	0.672	0.708	0.693	0.653	0.664	0.668	0.693	0.667	0.610
Greece	0.596	0.697	0.630	0.625	0.610	0.654	0.638	0.607	0.592	0.633	0.642	0.652
Hungary	0.664	0.727	0.713	0.720	0.751	0.776	0.792	0.802	0.801	0.783	0.783	0.820
Ireland	0.582	0.658	0.590	0.582	0.655	0.636	0.643	0.661	0.663	0.738	0.767	0.780

Italy	0.716	0.748	0.693	0.680	0.695	0.708	0.691	0.719	0.680	0.724	0.707	0.689
Latvia	0.782	0.823	0.793	0.803	0.792	0.792	0.791	0.802	0.836	0.847	0.867	0.803
Lithuania	0.753	0.755	0.756	0.759	0.750	0.759	0.732	0.698	0.699	0.791	0.743	0.677
Luxembourg	0.722	0.763	0.719	0.719	0.725	0.701	0.700	0.678	0.666	0.700	0.656	0.610
Netherlands	0.675	0.736	0.742	0.742	0.717	0.712	0.707	0.723	0.724	0.758	0.725	0.674
Poland	0.573	0.649	0.639	0.656	0.650	0.644	0.634	0.629	0.588	0.574	0.583	0.539
Portugal	0.641	0.673	0.687	0.744	0.744	0.740	0.757	0.774	0.754	0.744	0.769	0.776
Romania	0.783	0.825	0.762	0.759	0.776	0.778	0.715	0.699	0.677	0.723	0.703	0.679
Slovakia	0.658	0.656	0.665	0.693	0.739	0.744	0.721	0.735	0.754	0.788	0.724	0.645
Slovenia	0.678	0.705	0.701	0.711	0.736	0.749	0.750	0.747	0.685	0.717	0.748	0.755
Spain	0.626	0.799	0.799	0.782	0.708	0.696	0.688	0.665	0.615	0.643	0.683	0.665
Sweden	0.847	0.874	0.877	0.890	0.868	0.859	0.834	0.830	0.807	0.826	0.808	0.799
United Kingdom	0.798	0.808	0.795	0.806	0.781	0.796	0.786	0.771	0.813	0.845	0.809	0.789

For the second estimation (considering constant returns-to-scale) it can be seen from Table 2 that in 2012 Hungary, Latvia, Sweden, UK and Ireland are the five most efficient countries, while Estonia, Czech Republic, Poland, Bulgaria and Germany constitute the five least efficient countries. When compared to VRS results in Table 1 only Hungary changes its first position in VRS with the fifth position to Ireland in VRS when in CRS those two same places are the opposite. In terms of the least positions the last five positions are occupied by the same 5 countries in that same order in both VRS and CRS. In 2012 both Hungary and Latvia were 82% and 80.3% efficient and 18% and 19.7% inefficient, respectively, thus being less efficient when CRS are considered through DEA estimates (Table 2), when compared to the same obtained values (Table 2) through VRS-DEA for these same two countries (Hungary: 97.8% efficient and 2.2% inefficient and Latvia: 98.9% efficient and 1.1% inefficient).

In accordance to Table 2 Hungary is the most efficient country in 2012 where it accounts with a level of 82% of efficiency and the least efficient country is Estonia being only 41% efficient, thus putting forward the high disparities existing among the European group in terms of economic and environmental efficiency and conditions the need for higher steps if the goal is to turn equal the countries efficiency level. Although the technical eco-efficiency indicator provides the overall outcome for the economic and environmental efficiency of the joint use of capital, labor, and both renewable and non-renewable energy sources, it is still important to see which factors lay behind the good or bad performance of European countries in terms of eco-efficiency rankings.

Countries betting on renewable energy efficiently, substituting in a gradual way fossil energy like Hungary and Ireland, considered to have lower energy intensity or with a good performance in terms of energy intensity, also had a greater potential to move closer to efficiency levels of one (European Comission, 2014; Robaina-Alves et al., 2015). Investment in renewable energy undertaken by some countries, especially after the Kyoto Protocol, also differentiates that kind of "good behavior" because these countries initiatives to reduce emissions were noticed in the level of eco-efficiency of some countries.

5 CONCLUSION

This work explored ratio variables including Output ratio and Inputs ratios, such as, inputs labor and capital productivity, the weight of fossil energy and the share of renewable energy in GDP (gross domestic product), being the output GDP per GHG (greenhouse gases) emissions, to explain the eco-efficiency scores for 26 European countries between 2001 and 2012. We start by identifying the technical eco-efficiency rankings by using DEA-VRS and DEA-CRS models Our preliminary results show that, using DEA-VRS model in 2012 Ireland, Latvia, Sweden, Hungary and United Kingdom are the five most efficient countries, while Estonia, Czech Republic, Poland, Bulgaria and Germany constitute the five least efficient countries; while our results using DEA-CRS model show in 2012 Hungary, Latvia, Sweden, UK and Ireland are the five most efficient countries, while Estonia, Czech Republic, Poland, Bulgaria and Germany constitute the five least efficient countries. These evidences point for the fact that different input variables and models estimation provide different efficiency scores when compared to previous author's results. The worst performance observed in some countries might be attributed to remaining lobbies and renewable sources generation costs, which remain higher than that of conventional technologies. This effect, when combined with generous subsidies to renewable energy investors and protectionism policies into the energy production sector increases the use of non-renewable sources, despite their effective promotion from public policies and their recent increase in EU until 2011 (European Commission, 2014).

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Bidding and Optimization Strategies for Wind-PV Systems in Electricity Markets

I.L.R. Gomes[1], H.M.I. Pousinho[2], R. Melício[1,2], V.M.F. Mendes[1,3]

[1]*Departamento de Física, Escola de Ciências e Tecnologia, Universidade de Évora, Portugal*
[2]*IDMEC/LAETA, Instituto Superior Técnico, Universidade de Lisboa, Lisbon, Portugal*
[3]*Instituto Superior de Engenharia de Lisboa, Lisbon, Portugal; ruimelicio@gmail.com*

ABSTRACT

The variability in non-dispatchable power generation raises important challenges to the integration of renewable energy sources into the electricity power grid. This paper provides the coordinated trading of wind and photovoltaic energy to mitigate risks due to the wind and solar power variability, electricity prices, and financial penalties arising out the generation shortfall and surplus. The problem of wind-photovoltaic coordinated trading is formulated as a linear programming problem. The goal is to obtain the optimal bidding strategy that maximizes the total profit. The wind-photovoltaic coordinated operation is modeled and compared with the uncoordinated operation. A comparison of the models and relevant conclusions are drawn from an illustrative case study of the Iberian day-ahead electricity market.

KEYWORDS: Coordinated bidding strategies; wind-PV power system; linear programming; day-ahead market.

1 INTRODUCTION

For the next years power systems will likely show a substantially increased share of renewable energy of which a large portion will come from the variable renewable energy sources wind and photovoltaic [1]. Renewable energy grid integration increased in the E.U. to fulfill the Energy–2020 initiative [2]. The growth of renewable energy technologies is a notary fact and the market for all renewables advanced in 2014 with wind power and photovoltaic taking the lead for capacity additions [3]. The number of countries with renewable energy targets and policies increased again in 2014. As of early 2015, at least 164 countries had renewable energy targets, and an estimated 145 countries had renewable energy support policies in place [1]. Policies provide subsidy and incentives for renewable energy which include feed-in-tariff, guaranteed grid access, green certificates, investments incentives, tax credits and soft balancing costs [4].

A power producer in restructured electricity market is an entity owning power resources and participating in the market with the target of fronting the challenges of completion and uncertainty on electricity prices in order to achieve profit. Extra challenges for a wind-PV system owner come from the uncertainty on the availability of wind and solar resources meaning uncertainty in complying with power contracts [5]. The closing of the market defines power trading and price. In an attempt to reduce uncertainty from renewable energies, producers are required to provide day-ahead schedules of their generation. However, the remuneration depends on the conformity achieved on the level of the real deliver with the accepted value of the bid at the closing of the market. In absence of conformity, economic penalization for imbalances is due to happen [6]. Photovoltaic (PV) energy cannot provide a continuous source of energy due to the low availability during no-sun period and during winter. On the other hand, wind energy cannot satisfy constant load due to different magnitude of wind speed from one hour to another [7]. Typically wind farms has more availability of wind energy during the night and particular during the winter. From this point of view, wind-photovoltaic coordinated trading seems to mitigate some of the uncertainties and variability from one technology to other.

So, this paper is a research contribution for a possible wind-PV coordinated trading in order to conveniently accommodate bidding strategies by the use of a computer application based in a linear programming approach and therefore make a single bid.

2 STATE OF THE ART

A power producer from non-dispatchable renewable energy sources (like solar and wind) problem aims to find the optimal energy bids in a electricity market featuring financial penalties for energy imbalance [6], in order to maximize its revenue, reducing the risk of deviations and consequently penalties for imbalances. A photovoltaic power system is designed to operate in residential appliances [8], and with the use of storage devices. For wind power is proposed the use of stochastic optimization tools or work together with a hydro generation company to reduce the imbalances [9]. Joint operation of the uncertain renewable energy resources and other units is another method which can be used to reduce the imbalance costs [10].

In [11], a correlation between wind and solar power has been verified for the Iberian Peninsula, encouraging the coordination of wind-photovoltaic systems to mitigate the energy supply instability. In [12], an optimization approach to maximize profits of concentrated solar power plant Spain is proposed taking into account market prices. In [13], the optimal self-scheduling of the wind/CSP coordination is studied under a deterministic mixed-integer linear programming (MILP) approach, evaluating the impact on profit in the day-ahead market. In [14], the development of bidding strategies is investigated for a wind farm owner and a deterministic MILP approach for its optimal operation is proposed.

Surveys [12, 15, 16] reveal the absence of treatment of a coordinated configuration between wind and photovoltaic systems. In [17, 18], linear programming is proposed for a wind energy problem instead of mixed-integer nonlinear programming with consequent gain of robustness, simplicity, and computational efficiency. Therefore, linear programming can be also proposed for the coordination of wind and photovoltaic systems as is the case of this paper.

3 PROBLEM FORMULATION

Wind and PV energy are undispatchable and plagued by the major uncertainties that constitutes wind and solar irradiation availability. In addition to the intermittence and variability of wind and solar irradiation the wind-PV power producer must also cope with uncertain market prices. Thus, the market strategy of a coordinated wind-PV system producer must take into account these uncertainties in order to maximize its revenue for trading energy in day-head electricity markets, otherwise if not conveniently addressed it is possible to occur losses on profit due to imbalances penalties. The coordination of wind and PV energy can mitigate some of these uncertainties faced by the power producer working like a complement to each other. The system operator is responsible to maintaining the equilibrium between production and consumption.

3.1 Mechanism for Imbalance Prices

System imbalance is defined as a non-null difference on the trading between the delivered energy and the agreed amount of energy in a given moment. The power producer is assumed to be a responsible entity and pay the market imbalance price for any contribution to the global system imbalance. If there is an excess of delivered energy in the power system, the system imbalance is positive, otherwise the system imbalance is negative. In the electricity market in Iberian Peninsula, like in the rest of European electricity markets, is defined a price for the positive energy deviation and a price for the negative energy deviation for each time period. In addition, these prices depends on the imbalances in the whole power system. Thus, if the system imbalance is positive, i.e., excess of generation, the system operator purchase the energy in excess of the producers with excess of offers for a price smaller than the day-ahead market-clearing price and pays just the day-ahead price for the producers that produce less than the offer in the same market. The prices are as follow

$$\lambda_t^+ = \min(\lambda_t^D, \lambda_t^{DN}) \tag{1}$$

$$\lambda_t^- = \lambda_t^D \tag{2}$$

In (1) and (2), λ_t^+ and λ_t^- , are applied in the balancing market to the energy deviations, λ_t^D is the day-ahead market-clearing price and λ_t^{DN} is the price of the energy of offers in exceeds. Otherwise, if the system imbalance is negative, the price are as follow

$$\lambda_t^+ = \lambda_t^D \tag{3}$$

$$\lambda_t^- = \max(\lambda_t^D, \lambda_t^{UP}) \tag{4}$$

In (3), λ_t^{UP} is the price of the energy that needs to be added to the system.

3.2 Coordinated Wind-PV Bidding Strategy

The revenue from the coordinated wind-PV system of a power producer that offers and gets accepted a certain amount of energy for hour t is as follows

$$R_t = \lambda_t^D P_t^D + I_t - c^{PV} P_t^{PV} - c^W P_t^W \tag{5}$$

In (5), P_t^D is the power trade by the wind-PV power producer in the day-ahead market, I_t is the imbalance income resulting from the balancing process and may be negative, i.e., it may represent a cost. c^{PV} and c^W is the marginal cost of PV and wind power respectively. P_t^{PV} and P_t^W is the PV and wind power produced in each plant.

The total deviation incurred by the wind-PV producer for hour t is as follows

$$\Delta_t = P_t^{PV} + P_t^W - P_t^D \tag{6}$$

where $P_t^{PV} + P_t^W$ is the total actual power, resulting from the sum of PV and wind power, respectively, for hour t . I_t is as follows

$$I_t = \lambda_t^+ \Delta_t, \Delta_t \geq 0 \tag{7}$$

$$I_t = \lambda_t^- \Delta_t, \Delta_t < 0 \tag{8}$$

In (6), a positive deviation means the actual production is higher than the traded in the day-ahead market and a negative deviation means an actual production lower than the traded. Therefore, λ_t^+ is the price at which the wind and solar producer will be paid for its excess of generation and λ_t^- the price to be charged for the deficit of generation. Let

$$r_t^+ = \frac{\lambda_t^+}{\lambda_t^D}, r_t^+ \leq 1 \tag{9}$$

$$r_t^- = \frac{\lambda_t^-}{\lambda_t^D}, r_t^- \geq 1 \tag{10}$$

Then

$$I_t = \lambda_t^D r_t^+ \Delta_t, \Delta_t \geq 0 \tag{11}$$

$$I_t = \lambda_t^D r_t^- \Delta_t , \Delta_t < 0 \tag{12}$$

A wind-PV producer that needs to correct its energy deviations in the balancing market incurs an opportunity cost as it loses the chance of trading the deviated energy through the day-ahead market at a more competitive price. The revenue function in equation (5) can be reformulated, so that it explicitly reflects such an opportunity cost.

Two cases have to be considerate. If the energy deviation incurred by the wind-PV producer is positive, i.e., $\Delta_t > 0$, the revenue is given as follows as:

$$R_t = \lambda_t^D P_t^D + \lambda_t^D r_t^+ \Delta_t - c^{PV} P_t^{PV} - c^W P_t^W \tag{13}$$

Using the total deviation expressed in equation (6), the revenue is given as follows

$$R_t = \lambda_t^D (P_t^{PV} + P_t^W) - \lambda_t^D (1 - r_t^+)\Delta_t - c^{PV} P_t^{PV} - c^W P_t^W ,\ \Delta_t \geq 0 \tag{14}$$

If the energy deviation incurred by the wind-PV producer is negative, i.e., $\Delta_t < 0$, the revenue is given as follows

$$R_t = \lambda_t^D (P_t^{PV} + P_t^W) + \lambda_t^D (r_t^- - 1)\Delta_t - c^{PV} P_t^{PV} - c^W P_t^W ,\ \Delta_t < 0 \tag{15}$$

Equations (14) and (15) can be expressed in a general form as follows

$$R_t = \lambda_t^D (P_t^{PV} + P_t^W) - C_t - c^{PV} P_t^{PV} - c^W P_t^W \tag{16}$$

where

$$C_t = \lambda_t^D (1 - r_t^+)\Delta_t ,\ \Delta_t \geq 0 \tag{17}$$

$$C_t = -\lambda_t^D (r_t^- - 1)\Delta_t ,\ \Delta_t < 0 \tag{18}$$

In (16), the term $\lambda_t^D (P_t^{PV} + P_t^W)$ constitutes the maximum level of revenue that the wind-PV producer could collect from trading its energy production in a situation free of wind and solar irradiation uncertainty and without considering marginal costs. The term C_t represents the afore-mentioned opportunity cost, which results from trading the energy deviations in the balancing market at a less attractive price. The basic linear programming formulation for the optimal revenue of the wind and solar producer over a time horizon is obtained by the maximization of the objective function given as follows

$$\sum_{t=1}^{T} \left(\lambda_t^D P_t^D + \lambda_t^D r_t^+ \Delta_t^+ - \lambda_t^D r_t^- \Delta_t^- - c^{PV} P_t^{PV} - c^W P_t^W \right) \tag{19}$$

The maximization is subjected to constraints as follows

$$0 \leq P_t^D \leq (P^{PVm\acute{a}x} + P^{Wm\acute{a}x}), \forall t \tag{20}$$

$$\Delta_t = \left(P_t^{PV} + P_t^W - P_t^D \right), \forall t \tag{21}$$

$$\Delta_t = \Delta_t^+ - \Delta_t^- ,\ \forall t \tag{22}$$

$$0 \leq \Delta_t^+ \leq (P_t^{PV} + P_t^W), \forall t \tag{23}$$

$$0 \le \Delta_t^- \le (P^{PVmáx} + P^{Wmáx}) - (P_t^{PV} + P_t^W), \forall t \tag{24}$$

$$0 \le P_t^{PV} \le P^{PVmáx}, \forall t \tag{25}$$

$$0 \le P_t^W \le P^{Wmáx}, \forall t \tag{26}$$

In (20) the limit of offers is the maximum capacity in the coordinated wind-PV power plant. In (21) to (23) is imposed $\Delta_t^+ = 0$ when Δ_t^+ is negative, $P_t^{PV} + P_t^W < P_t^D$, and imposed $\Delta_t^- = 0$ when Δ_t^- is negative, $P_t^D < P_t^{PV} + P_t^W$. When imbalance is negative the wind-PV producer is penalized for the deficit of energy generated below the energy traded in the day-ahead market, so the term $\lambda_t^D r_t^+ \Delta_t^+$ is null and the term $\lambda_t^D r_t^- \Delta_t^-$ is subtracted from the revenue in the situation of no deviation, $\lambda_t^D P_t^D$. When the system imbalance is positive, the wind-PV producer is penalized for the energy generated above the energy traded in the day-ahead market, so that the term $\lambda_t^D r_t^- \Delta_t^-$ is null and the term $\lambda_t^D r_t^+ \Delta_t^+$ is added to the revenue in the situation of no deviation. In (24), the maximum negative deviation occur when the wind-PV producer sells the equivalent to the maximum capacity, $P^{PVmáx} + P^{Wmáx}$, but its final production is $P_t^{PV} + P_t^W$. In (25) and (26) the solar and wind power is set to be equal or less than the maximum capacity of the solar plant $P^{PVmáx}$ and wind plant $P^{Wmáx}$.

4 CASE STUDY

The data for the case study are from a coordinated wind-PV system deployed in the Iberian Peninsula with a wind farm of 100 MW of rated power and a PV power plant of rated power of 50 MW. The data for day-ahead prices and price multipliers r_t^+ e r_t^- are from the Iberian electricity market. The coordination is on an hourly basis with a 24h range for the day-ahead market. The plants share a line to connect to the grid. The proposed linear programming approach provides the maximization of the coordinated wind-PV system taking into account power forecasts, solar irradiation and market prices. An illustration of the coordinated wind-PV system is shown in Fig. 1.

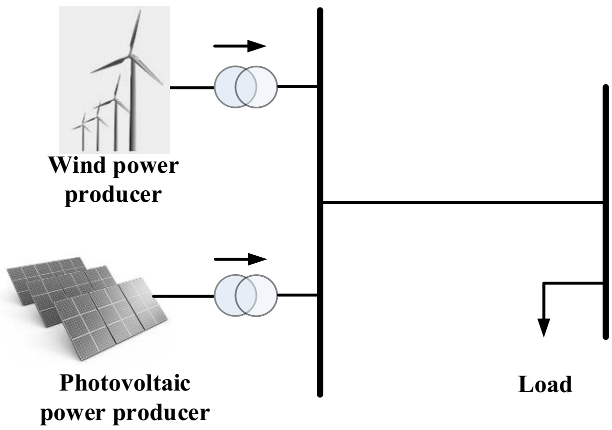

Fig 1. Coordinated Wind-PV system and transmission line.

The marginal cost of the wind farm is equal to 16 €/MWh and the marginal cost of the PV system is 29 €/MWh according to [19]. The coordinated wind-PV system aims to achieve the optimal single bid for the day-ahead market. The coordinated linear programming problem is programmed in the software GAMS.
The day-ahead market-clearing price is shown in Fig. 2.

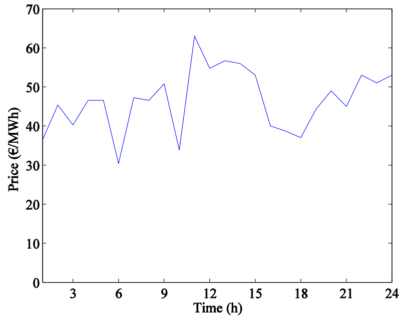

Fig 2. Day-ahead market-clearing price.

The imbalance price multipliers r_t^+ and r_t^- are shown Fig. 3.

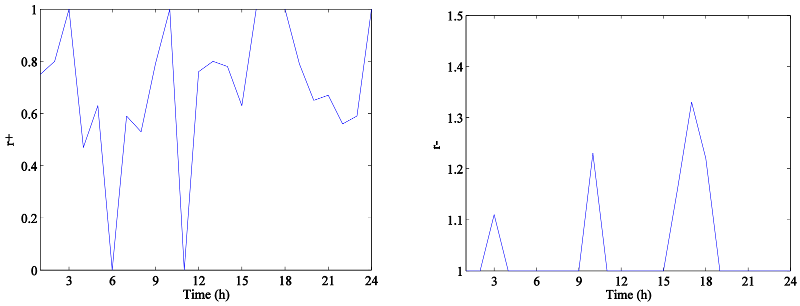

Fig 3. Imbalances price multipliers; left: r_t^+, right: r_t^-.

The wind and PV generation is obtained using the total energy produced along the 24h of the wind farm scaled to the maximum power of 100 MW and of the PV system scaled to 50 MW. The total energy produced by the wind farm and PV system are shown in Fig. 4.

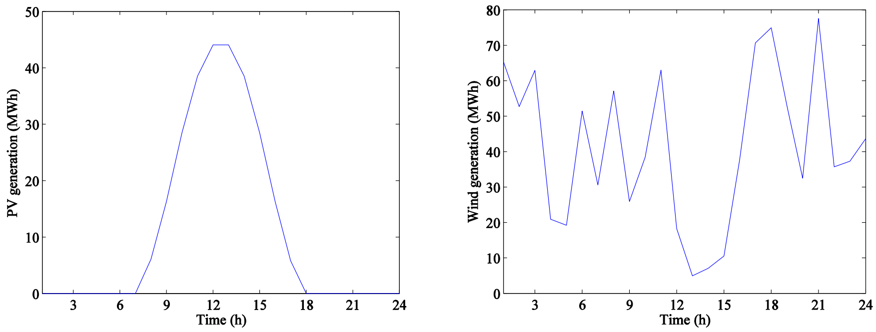

Fig 4. Generation; left: PV, right: wind.

The optimal single bid from the coordinated wind-PV system traded for the period of the 24h is the result of the proposed linear programming problem. The single bid result from the contribution of each technology, namely wind and PV. The total energy traded by the coordinated wind-PV system is shown in Fig. 5.

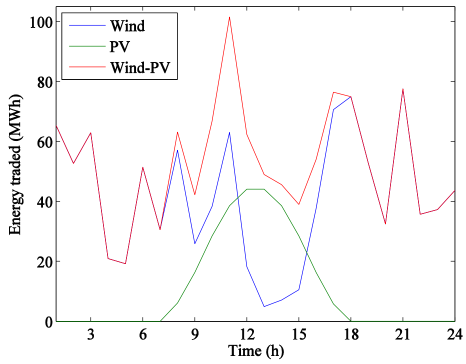

Fig 5. Energy traded (MWh).

The expected results with and without coordination are shown in Table 1.

Table 1. Results with and without coordination

Case	Energy traded (MWh)	Profit (€)	CPU Time (s)
Wind	990.89	28,343.22	0.062
PV	266.64	6,224.17	0.032
Coordinated Wind-PV	1279.53	34,969.39	0.125

Table I shows that Wind-PV coordination provides an improvement on total profit. Moreover, the amount of energy traded in the day-ahead market is higher for the coordinated system than for the separated power systems.

5 CONCLUSION

This paper presents the coordination of wind-PV systems for a power producer with the aim of trading energy with a single bid for aggregating wind and PV power production. A linear programming approach for solving the offering strategy of the power producer in a deregulated market is discussed and find how this two energy forms can complement each other. The main result is the bidding strategy for wind and solar producer facing the wind, solar irradiation and price uncertainties, as well the system imbalances which affect the price in case of deviations between the energy traded in the day-ahead market and the actual energy produced by the wind and solar producer. It is possible to see the complementarity of wind and solar power, with wind energy producing more energy at night and solar energy during the day. This can be a good strategy for renewable energy producers trying to cope with uncertainties of both wind and solar irradiation. Linear programming have been proposed for many studies about trading energy with renewable energy sources due to its robustness, simplicity and computational efficiency and in this paper the effectiveness of this approach is proved. A possible future work can be the use of a stochastic linear programming program, considering scenarios for wind and PV generation and market prices, for the coordination of a wind-PV system.

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The Merit-Order Effect of Energy Efficiency

Juan-Manuel Roldan-Fernandez[1], Manuel Burgos-Payan[2], Jesus-Manuel Riquelme-Santos[3] and Angel-Luis Trigo-Garcia[4]

Departamento de Ingeniería Eléctrica, Universidad de Sevilla,
Camino de los Descubrimientos, s/n. 41092, Sevilla. Spain
[1] jmroldan@us.es; [2] mburgos@us.es; [3] jsantos@us.es; [4] trigoal@us.es

ABSTRACT

The integration of certain amount of renewable generation in the wholesale market right-shifted the merit-order generation curve, which produces a noticeable reduction of the clearing price while slightly increases the traded energy (almost inelastic demand curve). The downward pressure on the clearing price is mainly due to the fact that the introduction of renewable generation bids with very low (even null) marginal cost, displaces to the right all kinds of conventional technologies (with higher marginal cost), including the technology which would otherwise have set the clearing market price. This right-shifted displacement of the merit-order generation curve leads to a lower wholesale clearing price, a small increment of the traded energy and a reduction of the total cost of the traded energy in the wholesale market. This is the key mechanism and its main effects on the market of the very well-known merit-order effect of the renewables, which is mainly related to the avoided cost of more expensive fossil fuel.

The promotion of energy-efficiency plans (industry and domestic) by policy-makers is expected to yield a reduction of the demand. As a result of the reduction of demand bids, the merit-order demand curve would experience a left-sifted displacement, which would produce a reduction of both the clearing price and the amount of traded energy. Consequently, the total cost of the traded energy also would diminish. As can be seen, the parallelism of the main effects on the market between the integration of renewable and energy efficiency evidences the existence of what can be called the merit-order effect of energy efficiency.

To analyze the characteristics of this merit-order effect of the energy efficiency, a simplified model, based on the linearization of the market around the clearing point, will be developed. This simplified model will also be used to compare the merit-order effect of energy efficiency and renewables. A set of scenarios with energy efficiency and renewables have been generated from the historic information of the Market Operator (OMIE) for the year 2014, in order to quantify what could have been its main effects on the Spanish/Iberian market.

KEYWORDS: Wholesale electricity market, Linearized market model, Merit-order effect, Energy efficiency, Renewable energy

INTRODUCTION

Once the supply and demand bids have been elaborated and submitted by the corresponding generation and demand agents, the Market Operator elaborates, for every hour of the day-ahead, a merit order dispatch by ordering the supply bids in ascending price order and demand bids in descending order. After that, and simplifying the complex optimization process that takes place, the Market Operator carries out the matching clearing point by the intersection of the merit order supply curve with the demand curve.

Since renewable generators extract the energy from a natural source (wind or sun, e.g.), they can produce electric power with very low operating costs. This allows renewable generators to submit their bids offering energy at very low (even null) marginal cost.

The methodology of elaboration of the merit order generation dispatch made that when a renewable generator offer a bid with certain amount of energy at very low cost, the Market Operator inserts the renewable bid by right-shifting the merit order generation/sale curve. This right-shifting produces a noticeable reduction of the clearing price while only slightly increases the traded energy, due to the characteristic lack of elasticity of the demand/buy curves.

As can be seen the downward pressure of the renewable generators on the clearing price is mainly due to the fact that the introduction of renewable generation bids with very low (even null) marginal cost, displaces to the right all kinds of conventional technologies (with higher marginal cost), including the technology which would otherwise have set the market clearing price. The integration of renewable induces a displacement of the operating point of the wholesale market towards a lower clearing price, a small increment of the traded energy and, as a consequence, a reduction of the total cost of the traded energy in the wholesale market. This is the key mechanism, and its main effects, on the market of the very well-known merit-order effect of renewables. The avoided amount of burned fossil fuel and the consequent reduction of CO_2 emissions due to the shifted fossil fuel generation leads to a secondary mechanism for reducing the clearing price of energy, as the reduction of the demand of fossil fuel and CO_2 emission allowances reduces the demand of both the fuel (in the international market) as well as of the CO_2 emission allowances, putting a downward pressure on its prices and thus reducing the costs of the remainder cleared fossil fuel-based generators.

The interest of consumers (industry and domestic) to reduce their energy bills and the promotion of energy-efficiency plans by policy-makers is expected to yield a reduction of the demand. As a result of the reduction of demand bids, the merit order demand/buy curve would experience a left-shifted displacement, which would produce a reduction of both the clearing price and the amount of traded energy. Consequently, the total cost of the traded energy would also diminish. Again, the avoided burning of fossil fuel and CO_2 emissions due to the fossil fuel not required lead to a secondary via for reducing the clearing price of energy, as this reduces the costs of the remainder cleared fossil fuel-based generators.

As can be seen, the parallelism of the effects on the market between the integration of renewable and energy efficiency demonstrates the existence of what could be called the merit-order effect of energy efficiency. This work seeks to analyze the characteristics of this merit-order effect of the energy efficiency and carry out a comparison with the corresponding characteristics of the merit-order effect of renewables. To achieve that purpose, a simplified model, based on the linearization of the market around the clearing point, will be used to explore some basic conjectures. Then an appropriate set of empirical-based scenarios with energy-efficiency as well as integration of renewables have been generated from the retrieved historic information of the Market Operator (OMIE) for the year 2014, in order to quantify the main effects on the Spanish/Iberian market.

After the introduction, the content of the paper is as follows. First the Spanish/Iberian electricity market is shortly surveyed and a simplified model, based on the linearization of the market around the clearing point, is used to check some hypothesis regarding the expected effects of energy-efficiency and renewables. Next, the hourly merit-order generation and demand curves for 2014, retrieved from the archive of the Market Operator (OMIE), are used as source data for the design of credible energy-efficiency and renewable scenarios. After that the main potential effects on the wholesale market are quantified and analyzed. The paper closes with the main findings of the comparison.

THE SPANISH/IBERIAN WHOLESALE MARKET

The joint European regional market for Spain (OMEL - Market Operator of the Spanish pole) and Portugal (OMIP - Market Operator of the Portuguese pole) is organized by OMIE (Operador del Mercado Ibérico de la Energía), the Market Operator of the Iberian Electricity Market. Although since 2014 OMIE is integrated in the European Price Coupling (EPC), this does not affect to the actual market clearing regulations (OMIE, 2014), which are under the rules of EUPHEMIA (EU + Pan-European Hybrid Electricity Market Integration Algorithm, the optimization algorithm commonly used by the European Electricity Markets to synchronously determine the electricity price) (EUPHEMIA, 2013).

The daily market is composed of 24 hourly markets that are cleared once a day by the Market Operator. The purpose of the daily market is the scheduling of electricity transactions for the day ahead which is performed through the submittal of electricity sale (generation) and purchase (demand) bids by their respective market agents. Two kinds of bids are considered in the Spanish/Iberian Electricity Market: simple and complex bids. Simple bids are just simple price and energy bids. Complex bids, only allowed for generation units, are bids which include any of the following conditions: indivisibility of blocks of energy, minimum income, scheduled stops and load gradient.

Once the supply and demand bids have been submitted by the agents, the Market Operator (OMIE/OMEL) elaborates, for every hour of the day-ahead, a merit order dispatch by ordering (by merit) the supply bids in ascending price order and demand bids in descending order. Firstly only the simple bids are considered to elaborate the merit order (aggregated) supply and demand curves. After that, the Market Operator carries out the simple matching clearing point by the intersection of the merit order supply curve with the demand curve. After that an iterative optimization algorithm finds a new solution, including the restrictions of the generation complex bids. After finishing the optimization procedure by means of EUPHEMIA, the final clearing price and traded energy are set for each hour of the day ahead. Finally, the System Operator (REE – Red Eléctrica de España) validates units schedule considering the technical constraints of the electrical system.

As often happens in optimization problems, as the number of restrictions increases the optimal solution impairs. In the case of the electricity market, complex offer generation bids (significantly) increase the final clearing price and (slightly) reduces the traded energy.

Conditionally on being dispatched, the price to be received or paid by the market participants is set according to a uniform-price auction. Irrespectively of their bids, the price producers receive or demand units pay is set equal to the highest accepted supply bid, the so-called system marginal price.

A SIMPLIFIED ANALYSIS OF THE PRICE FORMATION IN THE WHOLESALE MARKET

Figure 1 shows both the merit order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves as well as the traded energy ($W_i = 34183.4$ MWh) and the matching clearing price (p_i = 71.00 €/MWh) for a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market (OMIE). By its own nature, the supply curve, $p_G = p_G(W)$, has a (gentle) positive slope, while the demand curve, $p_D = p_D(W)$, has a very negative slope, as usually.

If the supply and demand curves were continuous (not stepped) and $m_G = dp_G(W)/dW > 0$ and $m_D = dp_D(W)/dW << 0$ were, respectively, the slopes of the supply (m_G = 1.4 €/GWh) and demand curves (m_D = –13.5 €/GWh) at the initial clearing point (A in Fig. 3), both the supply and demand curves could be linearly approximated, in the surrounding of the initial clearing point (W_i,p_i), as:

$$p_G(W) \simeq p_i + m_G(W - W_i) = p_i - m_G W_i + m_G W = p_{Gi} + m_G W$$

$$p_D(W) \simeq p_i + m_D(W - W_i) = p_i - m_D W_i + m_D W = p_{Di} + m_D W$$

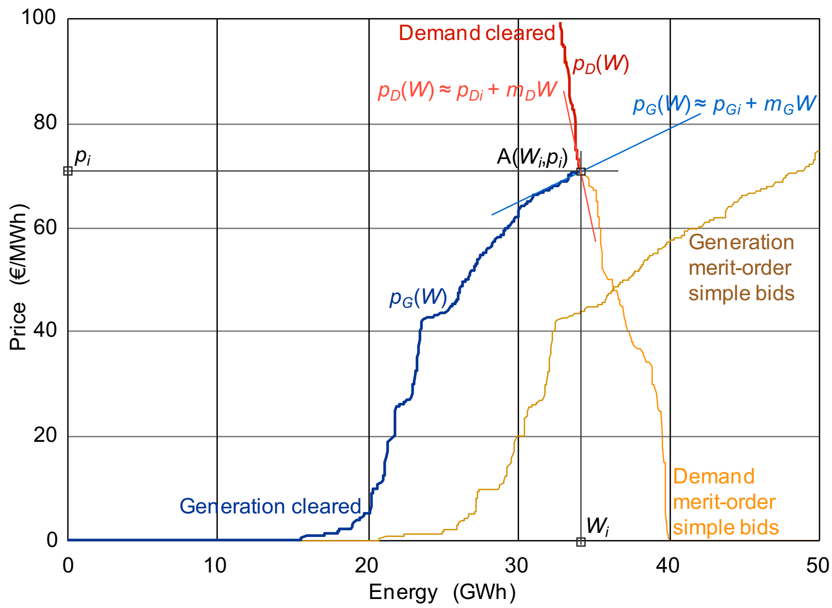

Figure 1. Merit order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves as well as the traded energy, W_i = 34.18 GWh, and the matching clearing price, p_i = 71.00 €/MWh, for a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market (OMIE). Linearization of the market around the initial matching point.

Where the respective ordinates at the origin of the linear approximations are:

$$p_{Gi} = p_i - m_G W_i$$

$$p_{Di} = p_i - m_D W_i$$

The total income for the producers (generators) or the total cost for consumers derived from the energy traded at the wholesale market, when only the market rules are considered, can be expressed as:

$$C(W_i) = W_i \cdot p_i$$

With this linearized market model around the clearing point, both the merit-order effect of renewable and energy efficiency are surveyed and compared in order to get a qualitative advance of the potential effects of these measurements on the performance of the market stakeholders.

Given that the wholesale market is a marginal market, the clearing point is the only thing that matters. This means that although the linear approximations of the merit order curves ($p_G \approx p_{Gi} + m_G W$ and $p_D \approx p_{Di} + m_D W$) are quite different of the actual generation and demand curves ($p_G = p_G(W)$ and $p_D = p_D(W)$), both sets of curves can lead to the same or very close clearing point.

Table 1 summarized the data corresponding to a peak hour (20:00 h) of a winter working day (Tuesday, February 10, 2015) in the wholesale Iberian market (OMIE) used in the following illustrative examples.

Table 1. Data for the linearization of the market around the initial clearing point corresponding to the merit order generation and demand curves for a winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market (OMIE).

	20:00 h
Energy traded (GWh)	$W_i = 34.18$
Clearing price (€/MWh)	$p_i = 71.00$
Generation slope (€/GWh)	$m_G = 1.4$
Demand slope (€/GWh)	$m_D = -13.5$

Renewables

Currently, the Spanish/Iberian market regulation requires that the Market Operator includes, preferably, all bids received from renewable generators, as long as it does not cause any risk or technical difficulty for the safe operation of the system. As a consequence, the integration of new renewable generation bids ($\Delta E_R > 0$) at very low (or even null) marginal price results mainly in a right-side shifting of the initial merit order generation curve. The linear approximation of this new offer curve, $p_{GR} = p_{GR}(W)$, is shown in Fig. 2 as a straight line parallel to the linear approximation of the primitive generation curve:

$$p_{GR}(W) = p_G(W - \Delta E_R) \simeq p_{Gi} + m_G(W - \Delta E_R) = p_{Gi} - m_G \Delta E_R + m_G W = p_{GRi} + m_G W$$

Where the ordinate at the origin of the new linear approximation is:

$$p_{GRi} = p_{Gi} - m_G \Delta E_R = p_i - m_G(W_i + \Delta E_R)$$

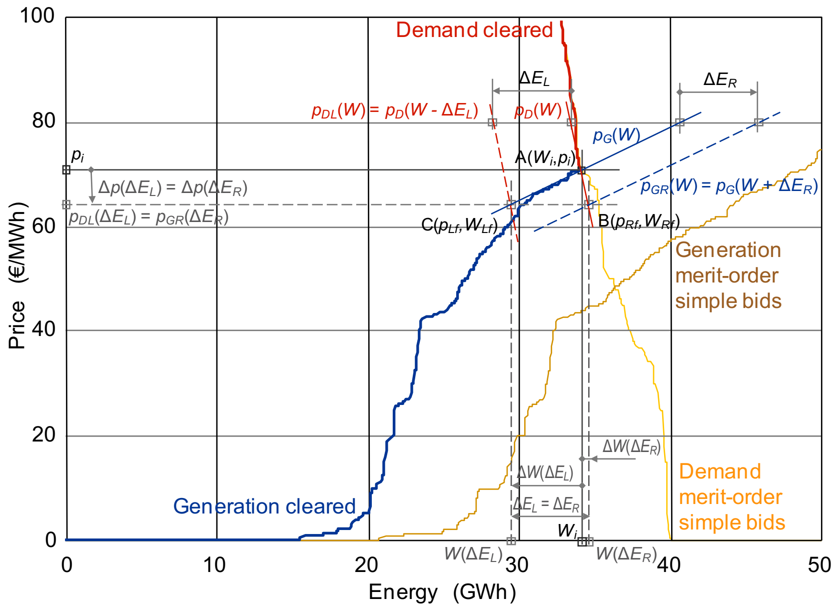

Figure 2. Merit order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves and matching clearing price ($p_i = 71.00$ €/MWh) and traded energy ($W_i = 34.18$ GWh) for a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market [OMIE]. Changes in the market clearing operating point due to the integration of renewable and energy efficiency bids.

With this linearized market model, the new clearing price and traded energy (B in Fig. 2) can be obtained equalling the new generation curve with the demand curve, as:

$$p_{GR}(W) \simeq p_{GRi} + m_G W = p_D(W) \simeq p_{Di} + m_D W$$

Now the traded energy, $W = W(\Delta E_R)$, can be expressed as:

$$W(\Delta E_R) \simeq \frac{p_{Di} - p_{GRi}}{m_G - m_D} = \frac{p_i - m_D W_i - p_i + m_G(W_i + \Delta E_R)}{m_G - m_D} = W_i + \frac{m_G}{m_G - m_D}\Delta E_R = W_i + \Delta W(\Delta E_R)$$

As a result, the increment of the traded energy can be approximated as:

$$\Delta W(\Delta E_R) \simeq \frac{m_G}{m_G - m_D}\Delta E_R > 0$$

The clearing price, $p_{GR}(W) = p_D(W)$, results:

$$p_{GR}(W = W_i + \Delta W(\Delta E_R)) \simeq p_{GRi} + m_G(W_i + \Delta W(\Delta E_R)) = p_i + \frac{m_G m_D}{m_G - m_D}\Delta E_R = p_i + \Delta p_R(\Delta E_R)$$

where the price variation (reduction) is:

$$\Delta p_R(\Delta E_R) = \frac{m_G m_D}{m_G - m_D}\Delta E_R < 0$$

It should be observed that since the slope of the supply is smaller than the absolute value of the corresponding to the demand curve ($0 < m_G << |m_D|$), the increment of traded energy result very much lesser than the increment of renewable energy bids integrated in the market:

$$0 < \frac{\Delta W(\Delta E_R)}{\Delta E_R} \simeq \frac{m_G}{m_G - m_D} \ll 1$$

This means that the clearing of certain amount of renewable energy bids, ΔE_R, by the Market Operator leaves out almost the same amount of energy bids from other more expensive and probably polluting production technologies, $\Delta W(\Delta E_R) << \Delta E_R$, and leads to a reduction of the hourly clearing price proportional to the amount of renewable energy integrated. This is the base of the so-called merit-order effect of the renewable energy (Burgos et al., 2013; Roldan et al. 2014; Saenz de Miera et al., 2008; Sensfuss et al., 2008).

Table 2. Linearized market model estimation of the variation of the traded energy, price and cost derived from the integration of certain amount of renewable energy, ΔE_R, and from the curtailment of certain amount of demand due to energy efficiency improvement, ΔE_L. (Data corresponding to a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) of the wholesale Iberian market (OMIE)).

	Renewables	
Relative variation of the traded energy	$\frac{\Delta W(\Delta E_R)}{\Delta E_R} \simeq \frac{m_G}{m_G - m_D} > 0$	0.09
Relative variation of the clearing price (€/MWh^2)	$\frac{\Delta p_R(\Delta E_R)}{\Delta E_R} \simeq \frac{m_G m_D}{m_G - m_D} < 0$	$-1.27 \cdot 10^{-3}$
Relative variation of the cost of the energy traded (€/MWh)	$\frac{\Delta C(\Delta E_R)}{\Delta E_R} \simeq \frac{(W_i m_D + p_i) m_G}{m_G - m_D} \ll 0$	$-36.69 \cdot 10^{-3}$
	Energy efficiency	
Relative variation of the traded energy	$\frac{\Delta W(\Delta E_L)}{\Delta E_L} \simeq \frac{m_D}{m_G - m_D} < 0$	-0.91
Relative variation of the clearing price (€/MWh^2)	$\frac{\Delta p_L(\Delta E_L)}{\Delta E_L} \simeq \frac{m_G m_D}{m_G - m_D} < 0$	$-1.27 \cdot 10^{-3}$
Relative variation of the cost of the energy traded (€/MWh)	$\frac{\Delta C(\Delta E_L)}{\Delta E_L} \simeq \frac{(W_i m_G + p_i) m_D}{m_G - m_D} \ll 0$	-107.69
	Comparison	
Relative variation of the traded energy	$\frac{\Delta W(\Delta E_R = \Delta E)}{\Delta W(\Delta E_L = \Delta E)} \simeq \frac{m_G}{m_D} < 0$	-0.1
Relative variation of the clearing price	$\frac{\Delta p_R(\Delta E_R = \Delta E)}{\Delta p_L(\Delta E_L = \Delta E)} \simeq \frac{m_G m_D}{m_G - m_D} \frac{m_G - m_D}{m_G m_D} = 1$	1.00
Relative variation of the cost of the traded energy	$\frac{\Delta C(\Delta E_R = \Delta E)}{\Delta C(\Delta E_L = \Delta E)} \simeq \frac{(W_i m_D + p_i) m_G}{(W_i m_G + p_i) m_D} < 1$	0.34
Relative variation of the sum of the traded energy	$\frac{\Delta W(\Delta E_R = \Delta E) - \Delta W(\Delta E_L = \Delta E)}{\Delta E} \simeq \frac{m_G - m_D}{m_G - m_D} = 1$	1.00

Therefore, the integration of certain quantity of renewable energy bids, ΔE_R, by the Market Operator yields a reduction of the cost of the traded energy ($\Delta C(\Delta E_R) << 0$) which is proportional to the amount of renewable energy integrated.

As an example, Table 2 summarized the results corresponding to the variation of the traded energy, clearing price and economic volume of the traded energy derived from the integration of certain amount of renewable energy, ΔE_R, for the illustrative example (Table 1).

Energy efficiency

Consumers that apply for energy efficiency programs expect to save in the electricity energy bill, mainly due to the projected energy saving ((Darbi, 2006; Darbi, 2010; Faruqui, 2010; Vine, 2013). The curtailment of certain amount of demand bids ($\Delta E_L > 0$) at high marginal price, where the energy efficiency actions would be more cost-efficient, produces a left-shifting of the initial merit order demand curve. The linear approximation of this new demand curve, $p_{DL} = p_{DL}(W)$, is shown in Fig. 2 as a straight line parallel to the primitive linear approximation of the demand curve:

$$p_{DL}(W) = p_D(W + \Delta E_L) \simeq p_{Di} + m_D(W + \Delta E_L) = p_{Di} + m_D \Delta E_L + m_D W = p_{DLi} + m_D W$$

Where:

$$p_{DLi} = p_{Di} + m_D \Delta E_L = p_i - m_D(W_i - \Delta E_L)$$

Now, the new clearing price and traded energy (C in Fig. 2) can be obtained equalling the new (reduced) demand curve with the primitive generation curve. As an example, central part of Table 2 summarized the results corresponding to the illustrative example (Table 1). Since the slope of the supply is much smaller than the corresponding to the demand curve, in absolute value ($0 < m_G << |m_D|$), the reduction of traded energy result almost equal (but something smaller) than the avoided demand bids:

$$0 > \frac{\Delta W(\Delta E_L)}{\Delta E_L} \simeq \frac{m_D}{m_G - m_D} > -1$$

Hence, the saving of some quantity of demand bids resulting from certain energy efficiency improvement of the consumers, ΔE_L, makes the Market Operator leaving out almost the same amount of generation bids from more expensive production technologies, $W_L(\Delta E_L) \cong \Delta E_L$, and yields a reduction of the clearing price and of the cost of the traded energy which are proportional to the amount of saved energy bids. This is the base of the merit-order effect of the energy efficiency which is very similar to the corresponding to renewables.

Finally, the variation (reduction) of the cost of the energy traded in the market can also be approximate as:

$$\Delta C(\Delta E_R) \simeq \frac{(W_i m_D + p_i) m_G}{m_G - m_D} \Delta E_R \ll 0$$

Therefore, the curtailment of some amount of demand bids resulting from energy efficiency improvement of the consumers, ΔE_L, yields a reduction of the total cost of the traded energy ($\Delta C(\Delta E_L) << 0$) which is proportional to the amount of saved energy bids.

Finally, comparing the intensity of the merit-order effect of energy efficiency and renewables ($\Delta E_R = \Delta E_L = \Delta E$, bottom part of Table 2), the following conclusions can be stated:

Finally, a comparison of the intensity of the merit-order effect of energy efficiency and the corresponding to renewables ($\Delta E_R = \Delta E_L = \Delta E$, bottom part of Table 2), allows the following conclusions:

- The reduction of the market clearing price is the same for both the energy efficiency and the renewable scenarios.
- The energy efficiency scenario leads to a reduction of the traded energy which is almost equal to the saved energy while the renewable case leads to a slight increment of the traded energy. This means that the energy efficiency is a more effective tool at removing the more expensive and probably polluting generation technologies.
- The reduction of the total cost of the traded energy in the energy efficiency scenario is greater than the corresponding to the renewable case, since the reduction in the efficiency scenario benefits from the reduction of the clearing price but also from the reduction of the traded energy.

Table 3 summarizes the similarities and differences between these two types of merit-order effect, considering the same amount el energy efficiency and renewable bids.

Table 3. Qualitative comparisons of the intensity of the two kinds of merit-order effect to modify the traded energy, clearing price and total cost of the traded energy.

Merit-order effect	Traded energy ΔW	Clearing price Δp	Cost of the energy ΔC
Renewables	↑	↓↓	↓
Energy efficiency	↓↓	↓↓	↓↓

RESULTS

Tables 4 and 5 summarized the results of the energy efficiency (small consumers) and renewable cases for Spain along 2014. More precisely, Table 4 summarizes the mean values of the variations of the annual traded energy, hourly clearing price and annual cost of the traded energy, while Table 5 shows the mean values of the rate of variation with the energy saving and renewable bids of the annual traded energy, hourly clearing price and annual cost of the traded energy. As anticipated by the linear model approximation, the results lead to the following main conclusions:

- For the energy efficiency scenarios, the mean values of the yearly traded energy, the hourly clearing price and the annual cost of the traded energy are always smaller than the corresponding to the base case, and their reductions grow almost linearly with the amount of load-saving bids.
- For the corresponding renewable cases the traded energy is always slightly greater that the corresponding to de base case and its increment grows with the amount of renewable bids. On the contrary, the clearing price and the cost of the traded energy are smaller than for the base case, and their reductions grow with the quantity of renewable bids.

When the same amount of load-saving and renewable bids is considered ($\Delta E_R = \Delta E_L = \Delta E$):

- The clearing price (and its variation) for energy efficiency is almost the same than for renewables, $\Delta p(\Delta E_R = \Delta E) \approx \Delta p(\Delta E_L = \Delta E)$.
- The intensity of the variation of the traded energy (absolute value), $\Delta W(\Delta E)/\Delta E$, and cost of the traded energy, $\Delta C(\Delta E)/\Delta E$, is always stronger for energy efficiency than for renewables. More precisely, the intensities are $(\Delta W(\Delta E_R)/\Delta E_R)/(|\Delta W(\Delta E_L)|/\Delta E_L) \approx 2.4$ and $(\Delta C(\Delta E_R)/\Delta E_R)/(\Delta C(\Delta E_L)/\Delta E_L) \approx 1.6$, respectively.
- The addition of the reduction of the traded energy for the efficiency scenario and the increment of the traded energy for the corresponding renewable scenario is almost equal to the amount of saving load bids or the renewable energy bids, $\Delta W(\Delta E_R) - \Delta W(\Delta E_L) \approx \Delta E$.

Table 4. Mean values of the variations of the yearly traded energy, hourly clearing price and yearly cost of the traded energy.

Spain 2014	Yearly mean	$W = 221$ TWh/y		$p = 42.13$ €/MWh		$C = 9346$ M€/y	
		$\Delta E = 0.5\%$ Load (0.90 TWh/y)		$\Delta E = 1\%$ Load (1.81 TWh/y)		$\Delta E = 2\%$ Load (3.62 TWh/y)	
Small consumers	Units	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*
$\Delta W(\Delta E)$	GWh	-607.59	250.18	-1207.66	507.88	-2417.48	1013.61
$\Delta p(\Delta E)$	€/MWh	-0.39	-0.39	-0.69	-0.69	-1.26	-1.26
$\Delta C(\Delta E)$	M€	-121.62	-82.97	-206.32	-129.02	-387.58	-232.99

$^*\Delta E_R = \Delta E_L = \Delta E$

Table 5. Mean values of the rate of variation with the load saving or renewable bids of the annual traded energy, hourly clearing price and yearly cost of the traded energy.

Spain 2014	Yearly mean	$W = 221$ TWh/y		$p = 42.13$ €/MWh		$C = 9346$ M€/y	
		$\Delta E = 0.5\%$ Load (0.90 TWh/y)		$\Delta E = 1\%$ Load (1.81 TWh/y)		$\Delta E = 2\%$ Load (3.62 TWh/y)	
Small consumers	Units	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*
$\Delta W(\Delta E)/\Delta E$	-	-0.68	0.27	-0.68	0.26	-0.68	0.26
$\Delta p(\Delta E)/\Delta E$	€/MWh^2	$-3.46\cdot10^{-3}$	$-3.46\cdot10^{-3}$	$-3.30\cdot10^{-3}$	$-3.30\cdot10^{-3}$	$-3.21\cdot10^{-3}$	$-3.21\cdot10^{-3}$
$\Delta C(\Delta E)/\Delta E$	€/MWh	-135.14	-92.19	-229.25	-143.36	-430.64	-258.87

$^*\Delta E_R = \Delta E_L = \Delta E$

CONCLUSION

The high and growing cost of the energy, the interest of both domestic and industrial consumers on reducing their energy bills or the promotion of energy-efficiency plans by policy-makers are expected to work as drivers for a reduction of the demand. Such a reduction of demand bids will produce a left-shifted displacement of the merit order demand/buy curve, which will produce a reduction of the clearing price, the amount of traded energy and, as a consequence, a reduction of the total cost of the traded energy.

The downward pressure of load saving and energy efficiency tools on the clearing price is mainly due to the fact that the displacement to the left of the merit order demand/buy curve produced by the reduction of demand bids, displaces the operating point of the wholesale market in such a way that the resulting clearing technology has a lower marginal costs than the technology which otherwise would have set the market clearing price. This is the key mechanism, and its main effects, on the market of merit-order effect of the energy efficiency which is very similar to the very well-known merit-order effect of renewables.

This work has introduced a simplified market model, based on the linearization of the wholesale market around the clearing point, to describe and quantify the merit-order effect of energy efficiency. This simplified tool has also been used to compare the intensity of the merit-order effect of energy efficiency and renewables. After that, from the archival information of the hourly markets for the year 2014, retrieved form OMIE, a set of heuristic-based scenarios considering energy efficiency and renewable generation have been generated and analyzed to estimate what could have been its main quantitative effects on the market.

The results of the heuristic-based scenarios confirm that, for the same amount of renewable and load saving bids, the intensity of the merit-order effect of energy efficiency (reduction of the traded energy, clearing price and traded energy cost) is even stronger than the corresponding to renewables. As a result, it can be concluded that energy efficiency scenario exhibits the best economic performance and environmental sustainability.

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MEASURING NON-RESIDENTIAL ELECTRIC ENERGY EFFICIENCY IN THE PORTUGUESE ECONOMY

Thomas Weyman-Jones[1], Júlia Mendonça Boucinha[2], Catarina Feteira Inácio[3], Pedro Miguel Martins[4],
[1]School of Business and Economics, Loughborough University, UK,
t.g.weyman-jones@lboro.ac.uk,
[2,3,4] EDP Serviço Universal, Lisboa, Portugal
Julia.Boucinha@edp.pt, CatarinaFeteira.Inacio@edp.pt, PedroMiguel.Martins@edp.pt

1. INTRODUCTION

In this paper we investigate the energy efficiency of non-residential electrical energy consumption in Portugal. Clearly the topic is in everyone's mind as the world experiences climate change, but we will discover that there are many confusions about what is meant by energy efficiency. The most widely used metric is the energy intensity of GDP, or in our context the ratio of non-residential electrical energy consumption (in kWh) to GDP at constant prices (in thousands of Euros). Amongst energy economists this metric has been widely criticised, and it is appropriate to ask whether in the field of efficiency and productivity analysis there is a more intelligent approach to the measurement of energy efficiency.

We will show how efficiency and productivity analysis has been used to develop a meaningful economic approach to measuring energy efficiency. This can be applied in both data envelopment analysis and stochastic frontier analysis, but in this paper we concentrate on the stochastic frontier analysis approach. Nevertheless, it soon becomes clear that the simple concept of energy efficiency – at least as it is represented in popular discussion – fails to take account of a major contribution of economic analysis known as the rebound effect. This rebound effect is derived from the fact that technological advances in energy efficiency of appliance and capital equipment use that reduce the amount of energy input needed to achieve a particular level of economic activity are equivalent to a reduction in the relative cost of energy. Such a reduction in the relative cost of energy has a substitution and an output effect on demand which can lead to an offsetting increase in energy demand as the benefits of lower costs are re-spent on energy intensive goods and services. This is the rebound effect.

There are particular issues that arise in measuring energy efficiency in individual countries. In this paper we consider the non-residential electricity consumption in a time series sample for the economy of Portugal from 1970 to 2014, a forty-five year period. The application of the standard stochastic frontier analysis model to a pure time series sample for a single country is not straightforward. There may be problems of autocorrelation and heteroscedasticity in the residuals which make their usual interpretation as components of idiosyncratic error and inefficiency problematic. In particular, both autocorrelation and heteroscedasticity lead to biases in measured inefficiency in the stochastic frontier analysis models. It is necessary therefore to develop efficient and consistent estimators of the usual error component parameters to measure inefficiency in a time-series context. We will suggest two different approaches to this modelling challenge.

In summary therefore, there are three major problems that confront researchers when measuring energy efficiency: a) the economic definition of the concept in the context of efficiency and productivity analysis; b) the allowance for the rebound effect which may cause efficiency savings to disappear immediately following technological change; c) the design of econometric estimators with attractive statistical properties.

Section 2 of the paper discusses the first issue: the definition of energy efficiency and section 3 analyses the relationship with the rebound effect. In section 4 we derive a model for estimation and examine the choice of estimators. Section 5 explains the data sample, sections 6 and 7 present the empirical results and discuss their interpretation. Section 8 concludes the paper.

2. MODELLING ENERGY EFFICIENCY

In this paper we examine energy efficiency in the non-residential electricity consumption, i.e. agriculture, industrial and services sector, in Portugal over the period 1970-2014 by econometric modelling of the variables that determine it.

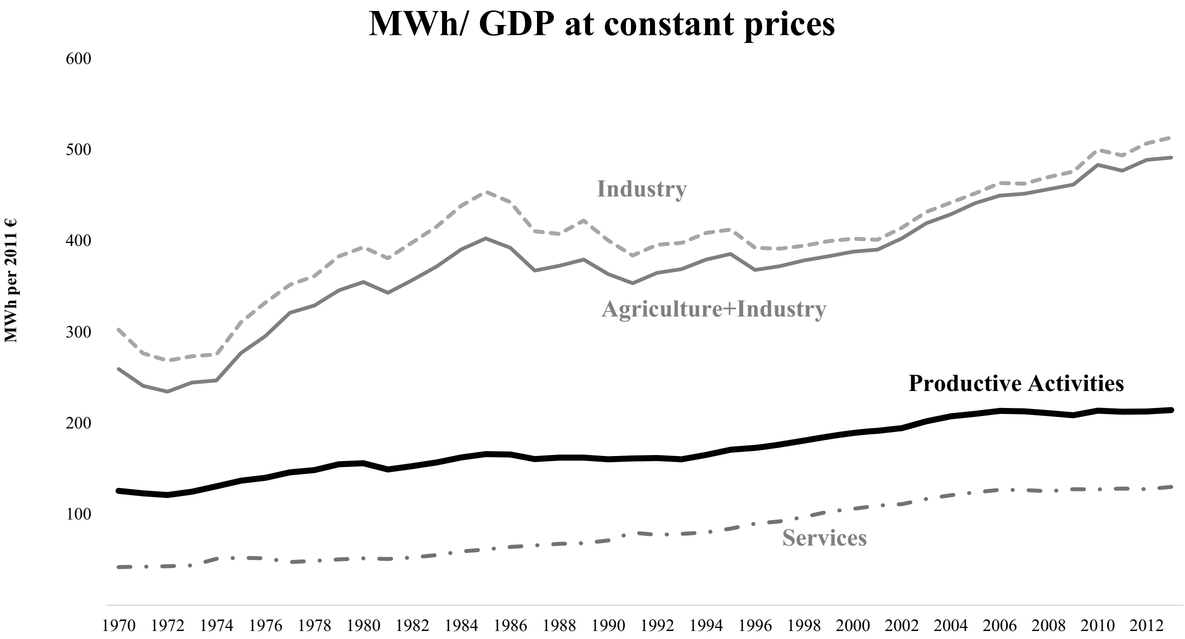
Begin with the standard energy intensity relationship:

$$energy\ intensity = E/Y \qquad [1]$$

Here E is energy consumption (or expenditure in real terms) and Y is the level of economic activity in the same sector, e.g. Y = GDP at the national level.

This is the standard measure of energy efficiency adopted widely in policy discussions and it has analogies with the simple crude measures of labour productivity that ignore other inputs, industrial characteristics and prices. In Figure 1, we illustrate this measure of electric energy intensity in Portugal for all productive activities and their sectoral composition. Electrical energy intensity has shown a steady increase over the period, and a superficial conclusion would be that electrical energy efficiency has decreased despite this being a period of increasing technological change.

Figure 1 Electrical Energy Intensity



However, as shown by Filippini and Hunt (2011, 2012), measuring energy efficiency through energy intensity is too simple because other variables and random errors impact on the measured intensity. They argued that energy demand can be modelled broadly as:

$$E_t = f(Y_t, other\ factors,\ energy\ efficiency, errors) \qquad [2]$$

Filippini and Hunt suggest that a stochastic frontier analysis can be used in this context, so that in this case the energy efficiency and the errors can be modelled as two components: u_t is an asymmetric randomly distributed inefficiency component and v_t is a zero mean idiosyncratic residual error.

The two error components can be separated only if they have distinct probability density functions; in that event maximum likelihood estimation or pseudo maximum likelihood or non-parametric procedures can be used to determine the parameters: $E(u), \sigma_u^2, \sigma_v^2$. In the standard stochastic frontier analysis the conditional mean of the inefficiency probability density function is used to measure energy efficiency

$$efficiency = exp\big(-E(u_t|(u_t + v_t))\big) \qquad [3]$$

Filippini and Hunt stress the generality and freedom from restrictive assumptions of these results as opposed to the very restrictive assumptions necessary to use the simple but misleading E/Y as the sole measure of energy efficiency. Several other researchers have followed the lead given by Filippini and Hunt, including Weyman-Jones et al (2015) in the case of residential electrical energy consumption in Portugal. Our aim in this paper is to extend the analysis to non-residential electric energy consumption. To do this we need to set up an explicit model. Prior to this it is important to note that we exclude a linear time trend from the list of variables. The reason for this is that the model itself is measuring the dynamic pattern of energy efficiency by treating each year as the behaviour of a separate representative producer. Including a time trend would unnecessarily restrict the behaviour of the model.

To analyse this model, we begin with the producer's short run cost function which depends on output activity, Y, the relative price of energy, P and a vector of other factors, Z. To minimize cost using energy input, E, the producer solves:

$$c(Y, P, \mathbf{Z}') = \min_E\{PE: Y = f(E, \mathbf{Z}')\} \qquad [4]$$

Now apply Shephard's lemma to derive the energy demand function

$$\partial c/\partial P = E = E(Y, P, \mathbf{Z}') \quad [5]$$

In this paper we will adopt a Cobb-Douglas representation of [6] for estimation:

$$\ln E_t = \alpha + \beta_Y \ln Y_t + \beta_P \ln P_t + \mathbf{z}_t{}'\boldsymbol{\gamma} + \varepsilon_t \quad [6]$$

The vector $\mathbf{z}_t{}'$ consists of exogenous variables which may be in log or ratio form. The stochastic frontier analysis specifies the composed error as:

$$\varepsilon_t = v_t + u_t \quad [7]$$

The probability density function for the inefficiency component is assumed to be half-normal but it can include conditional heteroscedasticity, and the idiosyncratic error component has the normal distribution.

$$u_t \sim iidN^+(0, \sigma_u^2) \quad \sigma_u^2 = \mathbf{z_t}'\boldsymbol{\theta} \quad [8]$$

$$v_t \sim iidN(0, \sigma_v^2) \quad [9]$$

The density function constants represented in [8] may include some of the exogenous variables in [6]. Note that the expression in [8] for the variance of the inefficiency component is a deterministic relationship and does not introduce an additional error term. Therefore exogenous variables may affect the position of the stochastic frontier as in [6] or may affect the distance of a producer from the frontier as in [8]. Estimation is by maximum likelihood, and each time series observation in this sample is treated as a separate producer.

This describes one of the models that we shall use to analyse energy efficiency in Portugal over the period 1970-2014. Nevertheless, there are two additional problems that must be addressed. These are (i) the appropriate interpretation of the findings about energy efficiency and (ii) the search for estimators that take account of the time-series nature of the sample. These issues are considered in the next two sections of the paper.

3. REBOUND EFFECTS

Saunders (2009) and Sorrell (2009) describe in detail a phenomenon that has been observed in empirical studies of energy efficiency: the rebound effect. This has a long history in resource economics, but has come particularly to the fore in the analysis of energy saving innovations. Put simply, despite huge advances in the technological innovations in energy saving, the observed improvements in energy efficiency at the aggregate level in many economies has been disappointing to many engineers and scientists. Energy savings often appear to be limited, ephemeral or even non-existent. Why might this be?

Economists explain the effect, in which energy efficiency savings are re-spent on energy consumption, as follows. After an initial improvement in energy efficiency due to technological advance, energy consumption is expected to fall. However this innovation causes a fall in the relative opportunity cost of energy. Consequently, energy using producers substitute consumption of energy intensive inputs for other inputs. In addition, consumption of all inputs including energy rises because producers are better off in terms of their input expenditure budgets. This in turn causes a rise in energy consumption. There is an analogous effect on consumers.

The economic explanation of this is the role of substitution and output effects. We have already demonstrated the derivation of the cost minimising demand for energy input, equations [5] and [6] above. Now consider the dual to this problem.

The dual competitive supply function is the result of maximising output subject to the producer's total cost budget constraint, which is equivalent to profit maximisation in a competitive market where the output price is an exogenous constant.

$$y(P, C, \mathbf{Z}') = \max_E\{Y = f(E, \mathbf{Z}'): PE = C\} \quad [10]$$

Applying the Envelope Theorem in the form of Roy's identity provides the output or profit maximising input demand function conditional on the input price, the producer's input expenditure budget and the exogenous variables, including the price of output.

$$-(\partial y/\partial P)/(\partial y/\partial C) = E = G(P, C, \mathbf{Z}') \quad [11]$$

For producers in a competitive market, the optimal input levels determined by output maximisation and cost minimisation must be identical, so that we can write

$$G(P, C, \mathbf{Z}') = E(Y, P, \mathbf{Z}') \quad [12]$$

Differentiating, then using Shephard's' lemma again and rearranging the result provides the Slutsky equation for the producer

$$\partial G/\partial P = \partial E/\partial P - E(\partial G/\partial C) \quad [13]$$

The first term on the right hand side is the Hicks-Slutsky substitution effect and the second term is the Hicks-Slutsky producer output effect.
The consequence is that technological innovations in energy delivery that lead to lower cost per unit in energy delivery will lead in turn to increased energy demand for two reasons: (i) the energy delivered is now relatively less expensive than other inputs permitting the producer to replace other inputs with increased energy intensiveness of production; (ii) the lower cost per unit in energy delivery will increase the purchasing power of the producer's input expenditure budget leading to an increase in the demand for all inputs including energy. When we examine empirical estimates of the demand for energy, therefore, we should expect a strong rebound effect of technical progress in energy efficiency not only from the relationship with the price of energy but also from the relationship with the level of output. Both factors will lead to increases in energy demand following the introduction of energy saving technological innovations. The output effect has been shown to be particularly important in many cases, Adetutu et al (2015, 2016) and it may turn out to be the case in the data for Portugal.
We can see how the changes in energy efficiency are related to changes in energy intensity. Taking equation [6] above, assuming that exogenous factors in the vector $\mathbf{z}'$ are constant and that the noise component v has mean zero, we differentiate with respect to time to achieve

$$(\partial \ln E/\partial t - \partial \ln Y/\partial t) = (\beta_Y - 1)(\partial \ln Y/\partial t) + \beta_P(\partial \ln P/\partial t) + du/dt \quad [14]$$

More succinctly,

$$\dot{\imath} = (\beta_Y - 1)\dot{y} + \beta_P\dot{p} - \dot{u} \quad [15]$$

In other words, the change in energy intensity ($\dot{\imath}$) equals the net effect of energy efficiency improvement ($-\dot{u}$), economic growth ($\dot{y}$) and exogenous energy price change ($\dot{p}$).
The innovations produce by definition a reduction in the opportunity cost of using the existing level of energy consumption to achieve the existing level of comfort and service or, in general terms, economic activity. This has both a substitution and an output (or income) effect. The substitution effect causes a switch of purchasing away from other inputs towards energy, and the output effect permits an increase in the expenditure on all inputs including energy. The result may be a rise in energy consumption – at least in the short run – above the previous level. This is the Rebound Effect. It appears as a reduction in energy efficiency in the mid-period following the beginning of the innovation period.
Finally in the long run the technological innovations may permit reductions in energy consumption even allowing for rebound as the innovations become completely embedded into the current state of technology.

4. ESTIMATION OF THE MODEL

Section 3 of the paper indicated a potential difficulty in interpreting the expected extent of energy efficiency savings from applying the specification in equation [6]. In this section we consider problems arising with the error term specification in equations [7] to [9]. Autocorrelated errors are likely to arise when our interest is in one country's aggregate energy demand in a time series sample. Autocorrelated errors raise two issues. There is the usual problem of non-iid-errors that the regression coefficient variances are not robust and the power of the usual significance tests is overestimated. The standard stochastic frontier analysis does not take account of autocorrelation or heteroscedasticity problems that are likely to arise in such samples, but this can be a serious omission since it is well-known that autocorrelated and heteroscedastic errors make the inefficiency estimates biased, inconsistent and inefficient, Kumbhakar and Lovell (2003). However in the problem of efficiency measurement at the aggregate economy level we effectively treat different sample periods as distinct production units each with its own efficiency rating. In this model the distance between the sample points and their relative distance to the frontier measures their relative efficiency. With autocorrelation, the error term for each sample point has a long memory and is closely adjacent to previous sample errors. This means that efficiency scores – the relative distance between the production units – are clustered together since the sequential sample points are treated as different production units. The effect is to make the whole sequence of efficiency scores cluster closely to 100 % efficiency, suggesting that there is little scope for energy efficiency saving.

To take account of this possibility, we consider again equation [7] but now we specify the error term as a first order autoregressive process, AR(1).

$$\varepsilon_t = \rho\varepsilon_{t-1} + w_t \quad [16]$$

The non-autocorrelated component is then treated as comprising the inefficiency and idiosyncratic error

$$w_t = v_t + u_t \quad [17]$$

It is no longer straightforward to estimate this form of the stochastic frontier analysis model directly by maximum likelihood estimation. Therefore we propose two alternative forms of estimation, based respectively on the quasi-maximum likelihood approach of Fan et al (1996) and the fixed-effects approach of Schmidt and Sickles (1984).
The first approach to the estimation in the presence of autocorrelated errors is adapted from the two-step quasi-maximum likelihood estimation suggested in Fan et al (1996).
To implement this estimation the steps are:
Step 1: estimate equation [6] with the following error term specification, by GLS

$$\varepsilon_t = \rho\varepsilon_{t-1} + v_t \quad [18]$$

Keep the GLS residuals:

$$e_t^{GLS} = y_t - \mathbf{x_t}'\widehat{\boldsymbol{\beta}}^{GLS} \quad [19]$$

Here we use the generic notation $(y, \mathbf{x}, \boldsymbol{\beta})$ to represent the variables and parameters in the model.
Step 2: replace the true regression parameters in the likelihood function for [6] by the GLS estimates treated as constants, and maximise the resulting concentrated quasi-likelihood function with respect to the parameters of the probability density functions for the error components in [8] and [9]. Henningsen and Kumbhakar (2009) and Kuosmanen et al (2015) explain how standard SFA applications can do this.
In the second approach, by adapting the analysis in Schmidt and Sickles (1984) we propose to estimate aggregate time effects (ATE) in order to measure inefficiency. We split the sample period into S non-overlapping sub-periods, S < T, in order to conserve degrees of freedom. We use dummy variables for these periods to represent shifts in the efficient frontier for different sub-periods – recall that each period is treated as a separate producer in the time-series sample. This produces the model:

$$\ln E_t = \alpha + \beta_Y \ln Y_t + \beta_P \ln P_t + \mathbf{z_t}'\boldsymbol{\gamma} + \textstyle\sum_{s=2}^{s=S} \delta_s D_{st} + \varepsilon_t \quad [20]$$

With error term

$$\varepsilon_t = \rho\varepsilon_{t-1} + v_t$$

This model can be estimated consistently and efficiently by Generalised Least Squares, GLS, with the AR(1) error process.
Here the energy efficiency is compared for S different sub-periods where D_{st} is a dummy variable which takes the value 1 when the observations are from a subperiod s = t, and zero otherwise.
Energy efficiency is measured by

$$Eff = exp(-\hat{u}_s) \quad [21]$$

Where

$$\hat{u}_s = \delta_s - \min_r(\delta_r) \quad [22]$$

In summary we estimate three different stochastic frontier analysis models for the relative efficiency of energy demand. The first consists of equations [6]-[9] which we will refer to as the stochastic frontier analysis model, SFA. The second consists of equations [6], [18], [19], [8] and [9], which we will refer to as two-step generalised least squares with quasi maximum likelihood, GLS-QML. The third consists of equations [6], [18], [21] and [2] which we will refer to as generalised least squares with aggregate time effects, GLS-ATE. We now turn to consider the data sample that we shall use.

5. DATA

The basic relationship is that of equation [6], for which we use the following annual time-series observations for Portugal covering the period 1970-2014.
E: Electricity consumption of productive activities (agriculture, industry and services) - GWh
Y: Real Portuguese Gross Domestic Product (2011 Euros)
P: Index of relative price of electricity in very high, high and medium voltage relative to a weighted average of fuel, gasoil and natural gas
Z_1 = *shareagind*: Share of Value Added of Agriculture and Industry in Productive Activities Value Added
Z_2 = *shareserv*: Share of Value Added of Services in Productive Activities Value Added (= 1-Z_1).
Z_3 = *NKS*, net capital stock at constant prices.
The sources of the data include EDP, Portuguese National Statistics Office (INE), Directorate General for Energy (DGEG), the Energy Regulator (ERSE) and the macroeconomic data base of the European Union, EU-AMECO.

Table 1 summary statistics for raw data

Variable	Obs	Mean	Std. Dev.	Min	Max
years	45	1992	13.13393	1970	2014
electrical energy	45	19411.43	9750.795	5064.009	33290.11
gdp at constant prices	45	127965	39837.46	59249.4	181506.6
relative price	45	51.10308	20.946	27.26374	104.9433
industry share of value added	45	0.308089	0.048293	0.232913	0.407406
services share of value added	45	0.691912	0.048293	0.592594	0.767087
net capital stock at constant prices	45	327.1178	148.3219	112.5	545.8

One problem arises with these data. Although an OLS regression with zero mean errors can be precisely estimated with both of the exogenous variables Z_1 and Z_3, the correlation matrix shows that they are strongly and negatively correlated. In other words, the major part of new investment in the capital stock in Portugal is associated with services sector output, which in turn is likely to have an impact on the relative demand for non-residential electrical energy. As a consequence when we estimated the different forms of the stochastic frontier analysis models: SFA, GLS-ATE, and GLS-QML, this negative correlation introduced considerable multicollinearity into the equation. Therefore we present two versions of each of the models, in one of which Z_1 = *shareagind*: Share of Value Added of Agriculture and Industry in Productive Activities Value Added is treated as an exogenous variable, and one in which Z_3 = *NKS*, net capital stock at constant prices is treated as exogenous.

6. EMPIRICAL RESULTS AND INTERPRETATION

Table 2 Empirical Results for five models

Dependent variable: log electrical energy demand in productive activities					
Variable	**SFA**	**GLS-QML 1**	**GLS-QML 2**	**GLS-ATE 1**	**GLS-ATE 2**
log gdp	1.0634***	1.407***	0.6362***	1.28***	0.7311***
log relative price	-0.0524**	-0.07551**	-0.04303§	-0.08425**	-0.06633*
industry share of value added	-1.2931***	-1.982***		-2.118***	
log net capital stock	0.3065***		0.6942***		0.6486***
constant	-3.8644**	-5.84814	-1.49204	-4.25001	-2.27819
N	45	44	44	44	44
AR(1) autocorr. errors	*No*	*Yes*	*Yes*	*Yes*	*Yes*
rho	0	0.5376	0.8061	0.3791	0.589
log likelihood	107.58	106.8	117.9	109.5	121.3
Estimation of efficiency	*JLMS conditional mean from MLE*	*JLMS conditional mean from Step 2 for Quasi Maximum Likelihood*	*JLMS conditional mean from Step 2 for Quasi Maximum Likelihood*	*Sub-period dummy variables for Schmidt-Sickles Aggregate Time Effects*	*Sub-period dummy variables for Schmidt-Sickles Aggregate Time Effects*

§ $p < 0.10$;* $p < 0.05$; ** $p < 0.01$; *** $p < 0.001$

The results of estimating the models are shown in table 2. All of the models are estimated with a considerable degree of precision with virtually all coefficients statistically significant at the 1 percent level. Heteroscedasticity-robust error covariance matrices are used to generate the standard errors in the GLS models.

The model reported in the first column of Table 2 is the conventional stochastic frontier analysis assuming non-autocorrelated errors. Efficiency is calculated by the JLMS measure of conditional mean efficiency. However, measured energy efficiency appears to be close to 100 percent across the sampled years, suggesting no potential for energy efficiency improvement since 1970. This is almost certainly an artefact of ignoring the possible autocorrelation in the errors. In the next two columns the model assumes autocorrelated errors from a first order autoregressive process, AR(1) and is estimated by GLS. The GLS errors are then decomposed using the QML estimator and the JLMS measure of conditional mean efficiency. The results in the third column of Table 2 also permit the variance of the inefficiency error component to be conditional on time in order to pick up the trend in energy efficiency. Finally in columns four and five of Table 2, we present the results for the model with autocorrelated errors estimated by GLS with the efficiency scores estimated by Schmidt-Sickles aggregate time effects. The results are broadly similar in terms of regression coefficients, precision of estimates (robust variances are used) and efficiency scores across both versions of each of the models with correction for autocorrelated errors. The resulting estimated energy efficiency scores for non-residential electrical energy consumption in productive activities are then illustrated in figures 2 and 3.

Figure 2 measured electrical energy efficiency: GLS-QML 2 estimates

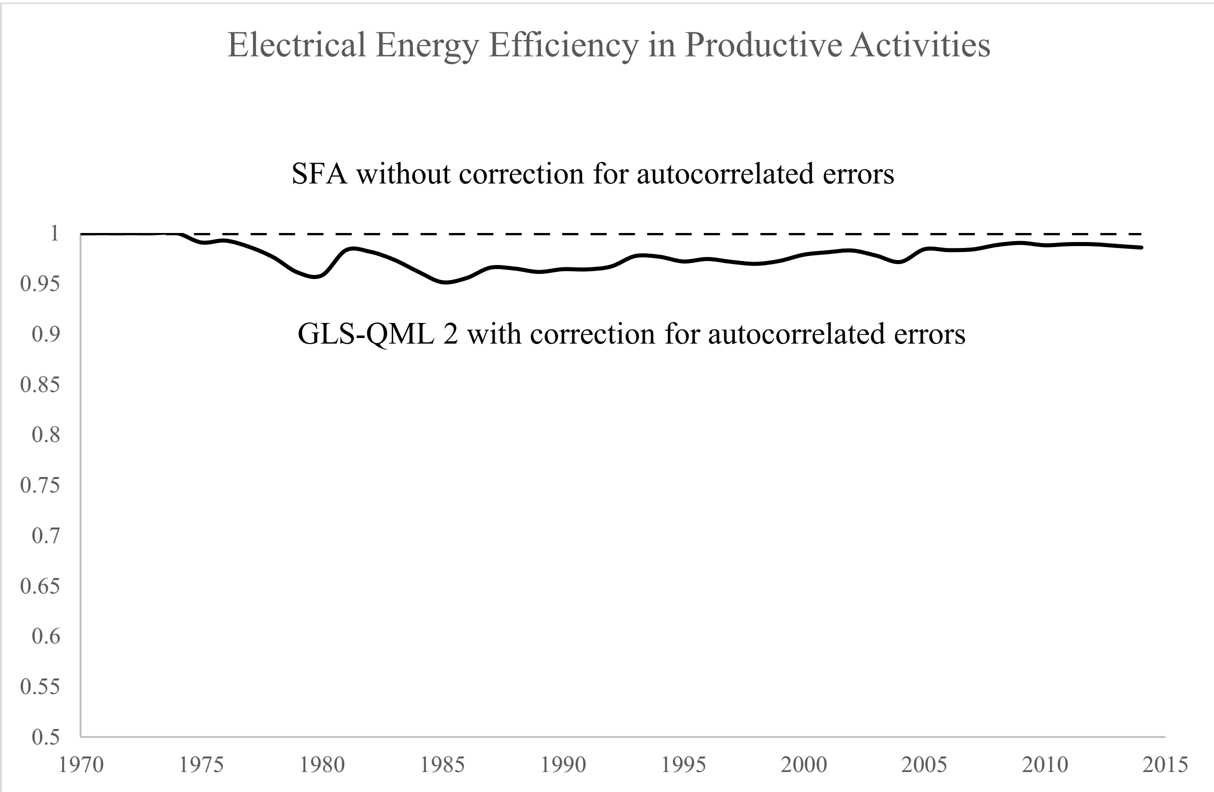
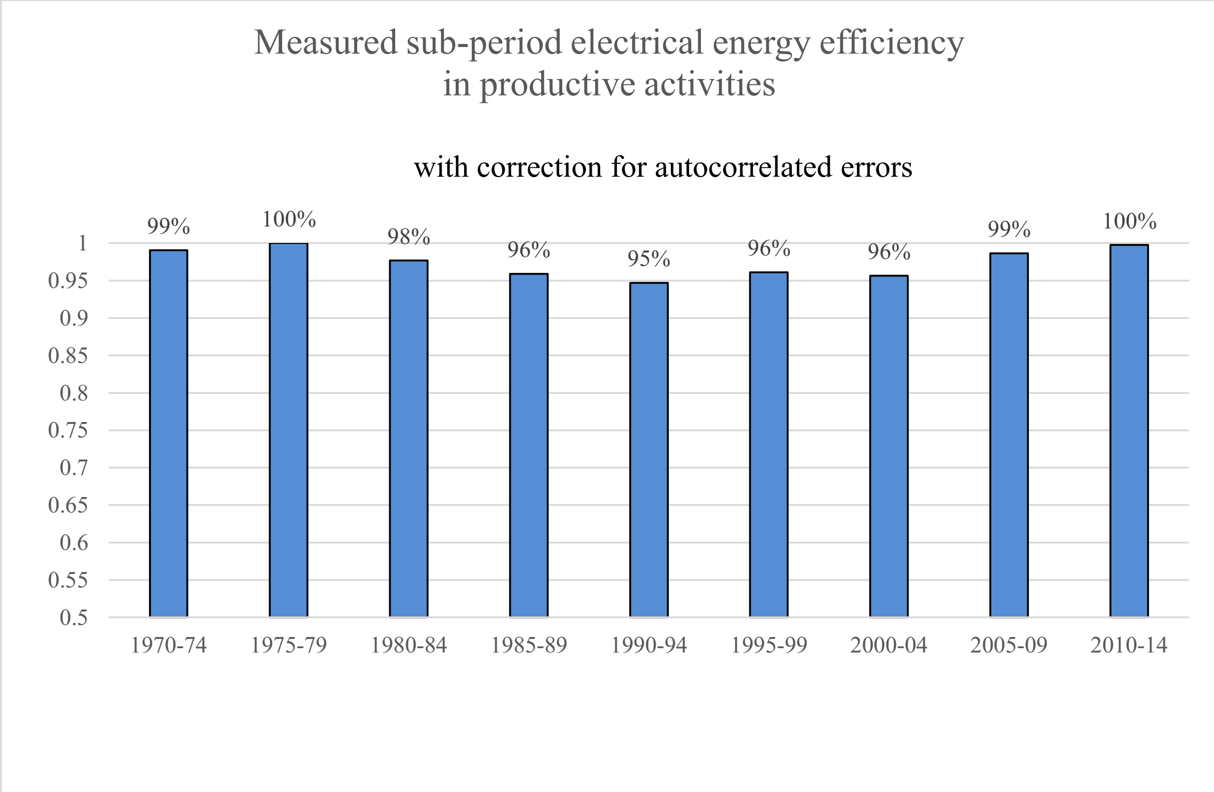


Figure 3 Model GLS-ATE 2 with autocorrelated errors



In Figure 2, we plot the dynamic efficiency scores profile from the second GLS-QML model and compare these with the conventional SFA model which finds little or no inefficiency. It is clear that taking account of the potential autocorrelation makes a real difference to the measured energy efficiency. Looking at the GLS-QML series with autoregressive error correction, as the period evolves, energy efficiency at first drops as innovation proceeds, possibly indicating rebound effects. Subsequently efficiency begins to recover slowly towards the end of the period.

In Figure 3 we present similar results for the sub-period efficiency scores computed from the GLS model with aggregate time effects and autocorrelated error correction. The same pattern is observable in figure 3 that we found in Figure 2: efficiency at first declined over the period from an almost fully efficient start, but then it began to indicate signs of improvement by the end of the period. This finding has been found in other studies and suggests that at first as innovation occurs there is no change in energy demand relative to economic activity and the price of energy. Subsequently, energy efficiency appears to fall because middle of the period observations appear to be further from the shifting frontier than at the beginning of the period. In other words the rebound effect is pushing up energy demand strongly relative to economic activity and the price of energy given the pace of innovation. Towards the end of the period, the energy efficiency scores may start to improve suggesting that efficiency gains are beginning to overcome the rebound effect.

It is interesting to note that in 2007 the Electricity Regulator (ERSE) launched The Plan for Promotion of Electric Energy Efficiency. The expected savings from those energy efficiency measures official initiatives in 2010-14 represent 1% of electricity consumption; hence, the results from these measures seem to be reflected in the increase in energy efficiency shown above.

7. THE ROLE OF ELECTRICITY IN OVERALL ENERGY EFFICIENCY

In order to complement our analysis, we have also tested some models to evaluate overall energy efficiency, between 1971 and 2014. The energy data was collected from DGEG. According to these results, total energy consumption in productive activities is sensitive to GDP, with an elasticity of -0.8, whereas the impact of the energy price is not statistically significant, see table 3 for the GLS estimates corrected for autoregressive errors.
Concerning energy efficiency, we could also identify three different sub-periods, given by applying the aggregate time effects dummy variables method used previously. Total energy efficiency was higher at the beginning of the period (between 1971 and 1985), then declined until 2006, and exhibited a major improvement (20%) after that. This increase in overall energy efficiency in productive activities is associated with the increasing share of electricity in total energy demand, as illustrated by the second model included in the same table. If we consider non-electrical energy consumption as the dependent variable, we have a statistically significant elasticity with respect to GDP; the impact of prices is not statistically different from zero and there is a strong negative relationship with the share of electricity in total energy. The comparison between these two models shows that part of the reduction in non-electrical energy consumption is explained by the increasing share of electricity in total energy consumption — for every percentage point increase in the share of electricity in total energy demand, non-electrical energy consumption falls by 5%.

Table 3 Results for GLS estimates of overall energy and non-electrical energy

Explanatory variables with correction for 1st order autoregressive errors	Dependent variable: log total energy	Dependent variable: log total energy excluding electricity
log gdp	0.7666**	0.6747***
log price of energy	-0.0689	0.0018
Share of electricity in total energy		-5.1864***
constant	7.2281*	9.6681***
N	44	44
AR(1) autocorr. errors	*Yes*	*Yes*
rho	0.4374	0.9722

* $p < 0.05$; ** $p < 0.01$; *** $p < 0.001$

8. CONCLUSIONS

In this paper, we have addressed three questions. The first concerned the definition of energy efficiency. Instead of the traditional engineering concept of an energy intensity ratio, we followed the lead of Filippini and Hunt and adopted a stochastic frontier analysis approach to measuring what should be a standard application of efficiency and productivity analysis to energy efficiency savings. This led us to develop a cost minimising model of energy demand with a two component error term. We apply this model to a time-series sample of non-residential electrical energy consumption in Portugal from 1970 to 2014.
The second question concerned the interpretation of empirical findings in energy consumption. We demonstrated that economic theory predicts a combination of substitution and output effects when the effective cost of energy is reduced through technological innovation. This can lead to a rebound effect as energy savings are re-spent on further demand for energy intensive inputs. Our discussion emphasised the care that is needed in the interpretation of a dynamic pattern of energy efficiency scores.
The third question reflected the fact that our sample treats the different time-series observations on the aggregate economy as the decisions of different producers. The standard application of stochastic frontier analysis to cross-section or panel data has to be reconsidered in the case of a pure time series sample. We derived two autocorrelation corrected GLS estimation procedures with robust standard errors to account for the time-series nature of the sample.

Our findings indicate two aspects in particular. Energy efficiency declined as innovation gained momentum probably because of the rebound effect. After some delay, energy efficiency may have started to recover towards the end of the period, possibly because policy initiatives are beginning to have an effect. In addition, it is important to correct for autocorrelated errors when measuring energy efficiency as an error component model in a time-series sample. The efficiency scores, where each year is treated as a separate producer, are different depending on whether autocorrelation of the error term is part of the specified model.

The issue of the appropriate way to measure energy efficiency improvements is critical to analysis of energy policy and a large volume of work lies ahead for energy researchers. However, the stochastic frontier analysis combined with the understanding of the rebound effect seems to offer a fruitful way forward. It is important however to take into account the error term assumptions that can be applied to the sample in question.

APPENDIX

The model with autoregressive errors is

$$y_t = \mathbf{x'}_t \boldsymbol{\beta} + \varepsilon_t \quad \text{[A1]}$$

$$\varepsilon_t = \rho\varepsilon_{t-1} + (v_t + u_t) \quad \text{[A2]}$$

We transform the variables by using the autoregressive parameter ρ: $y_t^* = (y_t - \rho y_{t-1})$ and $\mathbf{x}_t^* = (\mathbf{x}_t - \rho \mathbf{x}_{t-1})$ so that the model is

$$y_t^* = \mathbf{x}_t^{*\prime} \boldsymbol{\beta}^* + v_t + u_t \quad \text{[A3]}$$

In the expression above we use an augmented parameter vector to represent the frontier coefficients and the autoregressive parameter $\boldsymbol{\beta}^* = (\boldsymbol{\beta}, \rho)$. The log-likelihood function is therefore written as

$$\ln L(\mathbf{y}|\boldsymbol{\beta}^*, \lambda, \sigma^2) = const - (T)(\ln\sigma) - \tfrac{1}{2}(1/\sigma^2)\sum_{t=1}^{t=T}((v_t + u_t)^2) + \sum_{t=1}^{t=T}\ln\left[1 - \Phi\left((v_t + u_t)\lambda\sigma^{-1}\right)\right] \quad \text{[A4]}$$

Use the notation for the inverse Mills ratio: $\phi\left((v_t + u_t)\lambda\sigma^{-1}\right)/\left[1 - \Phi\left((v_t + u_t)\lambda\sigma^{-1}\right)\right] \equiv \phi_t/(1 - \Phi_t) \equiv h_t(\sigma, \lambda)$ to simplify the first order derivatives: $\partial \ln L/\partial \boldsymbol{\beta}^*$, $\partial \ln L/\partial\lambda$,$\partial \ln L/\partial\sigma$. $\partial \ln L/\partial\lambda = 0$ is not an analytical equation but can be used to concentrate $\hat{\sigma}^2$out to derive a set of K+1 equations which allow the estimators to be solved iteratively.

$$\partial \ln L/\partial \boldsymbol{\beta}^* = \left[\left(\sum_{t=1}^{t=T} \mathbf{x}_t^* \mathbf{x}_t^{*\prime}\right)\hat{\boldsymbol{\beta}}^* - \left(\sum_{t=1}^{t=T} \mathbf{x}_t^* y_t\right)\right] + (\lambda\sigma)\left(\sum_{t=1}^{t=T} h_t(\sigma,\lambda)\mathbf{x}_t^*\right) = \mathbf{0} \quad \text{[A5]}$$

$$\hat{\sigma}^2 = T^{-1}\sum_{t=1}^{t=T}(v_t + u_t)^2 = T^{-1}\sum_{t=1}^{t=T}\left(y_t^* - \mathbf{x}_t^{*\prime}\hat{\boldsymbol{\beta}}^*\right)^2 \quad \text{[A6]}$$

There are several reasons for not directly maximising this full information log-likelihood function with respect to the model parameters, $(\boldsymbol{\beta}^*, \lambda, \sigma)$. The parameters $\boldsymbol{\beta}^* = (\boldsymbol{\beta}, \rho)$ enter the model non-linearly with several over-identifying common factor representations. Direct estimation of ρ as a linear regression coefficient requires the lagged dependent variable. None of the currently available stochastic frontier analysis programming codes are able to proceed in this way. However, we can make use of a concentrated likelihood function approach suggested by Fan et al (1996). This has recently been used in a spatial autoregressive model by Glass et al (2015) and its use in non-parametric estimation is recommended by Kuosmanen et al (2015). We have adapted the Glass et al (2015) procedure to the problem in hand. This is essentially the modified ordinary least squares (MOLS) approach to stochastic frontier analysis. Following the argument in Fan et al (1996) replace the frontier expression by

$$\mathbf{x}_t^{*\prime}\boldsymbol{\beta}^* = E\left((y|\boldsymbol{\beta}, \rho)\right) + E(v) + E(u)$$

Therefore,

$$y_t = \left[E\left((y|\boldsymbol{\beta}, \rho)\right) + E(u)\right] + v_t + u_t$$

Then use

$$v_t + u_t = y_t - \left[\hat{E}\left((y|\boldsymbol{\beta}, \rho)\right) + E(u)\right]$$

to replace $v_t + u_t$ in the likelihood function where $\hat{E}\left((y|\boldsymbol{\beta}, \rho)\right)$ is a consistent estimator and, in the half-normal case,

$$E(u) = \mu = \mu(\lambda, \sigma) = \left(\sqrt{\frac{2}{\pi}}\right)\left(\frac{\sigma\lambda}{\sqrt{(1+\lambda^2)}}\right)$$

The first order conditions [A5]-[A6] are still valid even if the frontier is unknown $\mathbf{x}_t^{*\prime}\boldsymbol{\beta}^*$, provided it does not depend on $\sigma^2 = \sigma_v^2 + \sigma_u^2$ and $\lambda = \sigma_u/\sigma_v$. Looking at [A5]-[A6] this independence property of $\boldsymbol{\beta}^* = (\boldsymbol{\beta}, \rho)$ and (λ, σ) can be seen clearly. Following Glass et al (2015), we use a two-step procedure:

Step 1: Solve the GLS estimators with the GLS residuals, see [A5]:

$$\hat{\boldsymbol{\beta}}^{GLS} = \left(\sum_{t=1}^{t=T} \mathbf{x}_t^* \mathbf{x}_t^{*\prime}\right)^{-1}\left(\sum_{t=1}^{t=T} \mathbf{x}_t^* y_t^*\right)$$

$$e_t^{GLS} = y_t^* - \mathbf{x}_t^{*\prime}\hat{\boldsymbol{\beta}}^{GLS}$$

Adjust the residuals as follows

Calculate $\hat{\varepsilon}_t = e_t^{GLS} + \sigma\left(\sqrt{\frac{2}{\pi}}\right)\left(\frac{\lambda}{\sqrt{(1+\lambda^2)}}\right)$ and $\hat{\sigma}^2 = T^{-1}\sum(e_t^{GLS})/\left(1 - \frac{2}{\pi}\frac{\lambda^2}{1+\lambda^2}\right)$

Step 2: Now use these in the log-likelihood function to obtain the concentrated log-likelihood in terms of λ only:

$$\ln L(\mathbf{y}|\boldsymbol{\beta}^*(\lambda), \sigma^2(\lambda), \lambda) = l(\lambda) = -(T)(\ln\hat{\sigma}) - \tfrac{1}{2}(1/\hat{\sigma}^2)\sum_{t=1}^{T}(e_t^{GLS})^2 + \sum_{t=1}^{T}\ln[1 - \Phi(e_t^{GLS}\lambda\hat{\sigma}^{-1})]$$

Maximise this by grid search for $\hat{\lambda}$ and recalculate $\hat{\sigma}^2$. The efficient frontier is located by a MOLS (modified OLS) procedure in which $\hat{E}(u)$ is used to adjust the intercept. Alternatively use the Henningsen-Kumbhakar (2009) and Kuosmanen et al (2015) direct SFA procedure to implement the Fan et al (1996) two-step method, by stochastic frontier analysis regression of the GLS residuals e_t^{GLS} against a vector of values of 1.

Step 1: consistent estimation of the GLS model produces $y_t^* - \hat{E}\left((y_t^*|\mathbf{x}_t^*)\right) = y_t^* - \hat{y}_t^* = e_t^{GLS}$

Step 2: without adjustment, regress by stochastic frontier analysis

$$e_t^{GLS} = \mu[1] + (v_i + u_i)$$

This produces estimates of $\sigma^2 = \sigma_v^2 + \sigma_u^2$ and $\lambda = \sigma_u/\sigma_v$ from which efficiency scores are obtainable.

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Economic evaluation and analysis of the Iberian cross-border balancing reserve regulation mechanism: A study on the impact in the Portuguese Electrical System

Pedro Frade[1], Filipa Amorim[2], João Santana[3], Carlos Silva[4]

[1]*Instituto Superior Técnico&REN, Av. Rovisco Pais, Lisbon, Portugal, pedro.frade@ren.pt*

[2]*Instituto Superior Técnico, Av. Rovisco Pais, Lisbon, Portugal, filipa.amorim@tecnico.ulisboa.pt*

[3]*Instituto Superior Técnico, Av. Rovisco Pais, Lisbon, Portugal, jsantana@ist.utl.pt*

[4]*Instituto Superior Técnico, Av. Rovisco Pais, Lisbon, Portugal, carlos.santos.silva@ist.utl.pt*

ABSTRACT

The cross border balancing reserve regulation mechanism has historically existed within national contexts. In the Iberian case, since mid-2014, it has gained a transnational dimension, namely through the introduction of cross border balancing reserve regulation between the Portuguese and the Spanish Transmission System Operators (TSOs). This mechanism is a way to increase the electricity systems' efficiency and improve the reliability of its operation.

This paper evaluates the economic impact of the first year of this mechanism in Iberia, from the Portuguese system's perspective. The Iberian electricity system is one of the most influenced by the high penetration of intermittent renewables, and therefore one of the best candidates to experience increased benefits from the platform.

KEYWORDS: System Operator, Tertiary Reserve, Electricity Market, Cross Border Exchange

1. INTRODUCTION

The European power system is expected to integrate a considerable amount of renewable energy in the medium-term. In the Portuguese case, there is currently a considerable penetration of renewable energy. Data from 2014 mentioned that wind generation alone produces 24,1 % of the total electricity produced in Portugal; more than coal which has 22,6% and approximately double that of natural gas with 12,9 % [1]. Furthermore, the outlook is for the renewable share to increase. From the System Operator's (SO) point of view, this amount of renewable penetration introduces new challenges in the balance management due to limited predictability and controllability of the renewable resources. On the other hand, the European Commission's political goal is to incentivize further development of the internal Electricity Market and a harmonized balancing market across Europe, promoting the improvement of cooperation between all energy actors, where the cross border exchanges (CBX) are included [2].

The European Network of Transmission System Operators for Electricity (ENTSO-E) defines operating reserves for balancing actions in three categories: primary, secondary and tertiary reserves. The tertiary control reserve (reserve regulation) is the mechanism that allows the SO to maintain the equilibrium between consumption, generation and programmed interconnection**.**

Until the recent past in Europe, each country generally had its own balancing market design, which applied to their own control area and internal energy suppliers. Like other regions, as Northern Europe, and in the framework of the Electricity Regional Initiative South West Europe, the involved TSO's (REN, REE and RTE) have been working on the implementation of a Cross Border Balancing reserve regulation mechanisms. In 2013, two bilateral provisional solutions between REN-REE and REE-RTE were considered to allow the implementation of cross border balancing mechanisms, more specifically the sharing of reserve regulations. This temporary solution was based and adapted from the cross-border mechanism implemented between National Grid (England TSO) and RTE (French TSO), called BALIT (balancing inter TSO's) and was designed and developed by RTE. Meanwhile, the involved actors are studying the design and development of a long-term regional and permanent solution (REN-REE-RTE) multi TSO platform, extensible to other interconnected areas [4] [5]. The exchange of tertiary reserve between Iberian countries started in June 2014.

The goal of this work is to analyze the economic impact of the introduction of cross border balancing services, and in particular the reserve regulation mechanism in the Portuguese electricity system, on the first year of its implementation. The introduction of cross border balancing mechanisms started operating between Portugal and Spain in mid June of 2014. To simplify and help categorize our analysis, we will analyze the first twelve completed months of activity. As such, we will consider for this study the period between July 1st 2014 and June 30th 2015.

To this end, a brief description of the Portuguese tertiary electricity market is presented in the following section. Afterwards, a description of the platform exchange is performed and the decision process of tertiary assignation, the following section evaluates the economic value of the exchange transactions, comparing these transactions with the previous situation, the exclusive national tertiary market. The following section exemplify the calculation process for evaluation the economical results. Finally, the results and conclusions of this study in a daily and monthly basis are presented.

2. BRIEF INTRODUCTION TO THE TERTIRARY REGULATION MARKET

The energy sold in spot market, the quantity of equilibrium, Qe, does not always match the reality of the national consumption needs. It is almost impossible to exactly predict the consumption for a given hour. During an hour, the consumption has a dynamic behavior with several upward and/or downward variations caused by multiple factors (social, natural etc...).

Based on these previous considerations and after the spot market, two different "markets" at a national level are organized. These are the **tertiary reserve downward** and **upward** markets for each of the TSO's inserted in MIBEL (REN and REE) [10]. In the Portuguese case, the generation units that did not sell their energy on the Spot market provide to the respective System Operator the price that they are willing to receive to produce an additional quantity of energy. When all producers provide their prices (and respective quantities) to the SO, they are organized by ascending price (cheapest to most expensive) [7]. If the SO needs to mobilize a given quantity of energy upward, Qu (MWh), it will pay the marginal upward price, Pu (€/MWh) to the respective (s) producers (s). All suppliers, who produce this extra quantity of energy, requested by the SO will receive Pu for the energy they provide, that corresponds to the price of the last (more expensive) MW produced. This price is generally higher than the Spot Price, Ps, and corresponds to an "over cost" for the electrical System. This over cost is the difference of the tertiary regulation price upward mobilized and the market price (or Spot Price).

On the other side, the generation units who sold their energy on the Spot Market, provide to the SO the quantities and the correspondent price they are willing refund to reduce or stop production. When all producers provide their prices (and respective quantities) to the SO, his prices are organized by descending order (the agents who are available to refund more € to stop/reduce production are prioritized on the list). If the System Operator needs to mobilize a given quantity of energy downward, Qd, the respective producer(s) will pay (refund) the electric system, that correspond the price to downward, Pd. All suppliers who reduce this quantity of energy, requested by the SO, will refund the system in Pd that corresponds to the price of last (cheapest) MW reduced. It is important not to forget that this producer (s) had already received Ps for the energy sold in the Spot Market. Generally, Pd is lower than Ps, and in this case it occurs an over cost to the electrical system that corresponds to the difference between the Spot Price and the tertiary regulation price downward mobilized [3]. A simple exemplification can be observed in Fig.1.

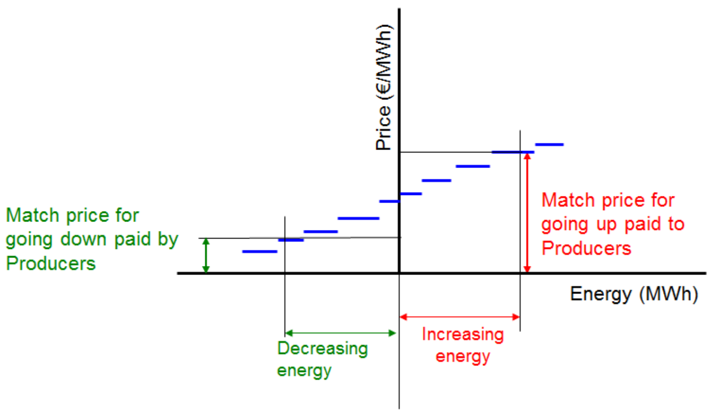

Fig. 1 - Tertiary reserve mobilization

3. BRIEF DESCRIPTION OF THE PLATFORM AND TSO EXCHANGES PROCESS

At each hour, TSOs using the common platform can send their offers for the following hour. These offers comprise the combination of 50MW hourly blocks with a given price in €/MWh and a upward or downward direction. The TSOs may submit up to ten offers in each direction (with a 500MW limit), provided that their respective systems are secured and interconnection capacity limits are respected.

The common IT platform realizing this process operates on a first come, first served basis. As an example, in the Portuguese case, only REE can activate REN offers (Portugal has a single neighborhood), while REE offers can be "disputed" between REN and RTE [6].

The Portuguese SO identifies the difference between Qe and the real consumption. If an energy gap is predicted in the next hour, it compares the reserve regulation prices with the Spanish TSO offer prices and will assign the Spanish offers if their price is more competitive than the national tertiary ones.

The participating TSO's send their respective offers for the next hour. Each offer is a 50MW hourly block combined with a price in €/MWh and a direction, either upward or downward. In each direction, REN and REE may submit up to ten offers representing a total capacity of 500MW, in each direction, provided that their own system is secured and that the interconnection capacity between Portugal and Spain allows it.

The process relies on the use of the same IT platform by all participating TSO's .The activation process is based on the first come, first served principle. Ex: In the Portuguese case, only REE can activate REN offers (Portugal has only one neighborhood) while the REE offers could be "disputed" by REN or RTE [6].

The Portuguese SO, identify and perspective the difference between Qe and the real consumption. If the SO predict a gap (lack or excess) of energy for the next hour, it will compared the reserve regulation prices with the Spanish TSO offer prices and will assigned the Spanish offers if they have a more competitive price than national tertiary offers.

4. ECONOMIC VALUE OF TERTIARY EXCHANGES

4.1. Import and Export Scenarios

The main goal of the cross border tertiary regulation exchanges is to reduce the over cost generated by the gap between the market results and the real consumption needs.

When there is a sharing of a certain quantity of reserve regulations, Q, between TSO's, it means that a business balance activation happened, BBA. The BBA's can be from two types depending on the TSO perspective: business balance imports, BBI, if the reference TSO will import reserve regulation from the adjacent TSO and a business balance exports, BBE, if the reference TSO will export reserve regulation to the adjacent TSO. In the case of this paper, we intend to analyze the impact of the BBA's in the Portuguese system perspective, so the Portuguese TSO (REN) will be the reference TSO.

In the case of BBI, the Portuguese TSO imports from the Spanish TSO a certain amount of reserve regulation, Q, at a certain Price of Balance Import (PBI), that corresponds to the Value of Balance Imports (VBI). To calculate the profit of each BBI, we need to calculate the alternative path: look for the Portuguese reserve regulation offers and t the correspondent Q at the correspondent price P(Q), in internal (national) market of reserve regulation. To calculate the profit (or savings) of the operation, we need to compare the cost of the tertiary reserve mobilized, CM, plus the cost of buying this energy to the adjacent TSO, instead of acquiring all our tertiary reserve internally, the cost of potential mobilization CPM, see Equation (1).

$$\boldsymbol{Profit\ of\ BBI = CPM - (VBI + CM)} \quad \textbf{(1)}$$

In the case of BBE, the Portuguese TSO sells (exports) to the Spanish TSO a certain Q at a certain Price of Balance Export, PBE (€/MWh) that corresponds to the Value of Balancing Export, VBE (€). To calculate the profit of each BBE we evaluate the value of our sell (VBE) and difference between the cost of tertiary reserve mobilized, the cost of mobilization, CM, (were contemplate the energy sold) and the cost of tertiary reserve if it was not occur tertiary exchange, the cost without mobilization, CWM, who represents the "only" the national tertiary needs. See Equation (2) [12].

$$\boldsymbol{Profit\ of\ BBE = VBE - (CM - CWM)} \quad \textbf{(2)}$$

5. THE VIRTUAL SITUATIONS - CPM AND CWM

CPM and CWM are scenarios of tertiary reserve that were not verified. These situations occur if the cross-border balance reserve regulation offers were not activated. To identify the energy and the respective price of the potential mobilization (import) or the scenarios where mobilization (export) would not occur , it was necessary to cross the energy activation (bought or sold) with to data information's [9]:

- The previous tertiary offers (available by the producers) for upward and downward at each hour, where the producers indicate the quantity and the respective price they are willing to produce for an extra quantity of energy; the quantity and price they are available to refund to the system reducing a determined quantity of energy [8].
- The tertiary offers (quantity and price) actually assigned in upward, Qu, and downward, Qd, for each hour [8].

The first step is observing the tertiary reserve offers upward and extracting all the energy blocks related with thermal units, which were stopped. The system operator, if intending to assign an offer from a stopped thermal unit may take into account the dynamic parameters and the related startup costs. Despite of centrals who was not sell in day or intra-day markets, they are represented in the upward tertiary offers but they are not available in real time. Assignment may be planned for several hours and with extra costs, such as the start-up costs, and with several constraints related with dynamic parameters. Simplifying, these tertiary offers are not "real-time" offers. After they are removed, we are left with net tertiary offers.

The second step is calculating our "virtual" tertiary assignment. As we referred, if the cross-border balancing services did not occur, this amount of energy must be assigned in the internal tertiary market. We need to sum Q to our assigned offers Qu or Qd and identify the quantity of energy upward without cross border balancing mechanisms, Quwb, and the correspondent price of upward without cross border balancing mechanisms, Puwb (Quwb), or the quantity of energy downward without cross border balancing mechanisms, Qdwb (MWh), and the correspondent price downward without cross-border balancing mechanisms. This corresponds to the potential internal offers assignment

5.1.CPM and Profit of BBI

After buy Spanish tertiary reserve for the following hour, three distinguish situations could occur as represented in Fig 2. It will be done a simple description of the calculation method of CPM and Profit of BBI. The first scenario is the "classical" scenario: if BBI did not occurred, it would be necessary mobilize (more) tertiary upward, see equation (4) and (5). In the second scenario, was mobilized tertiary downward, but if BBI did not occurred it would be necessary mobilize tertiary upward (Q > Qd), see equation (6) and (7). In third case was necessary mobilize tertiary downward but if BBI did not occurred, would not be necessary mobilize downward as much quantity as it was, equation (8) e (9).

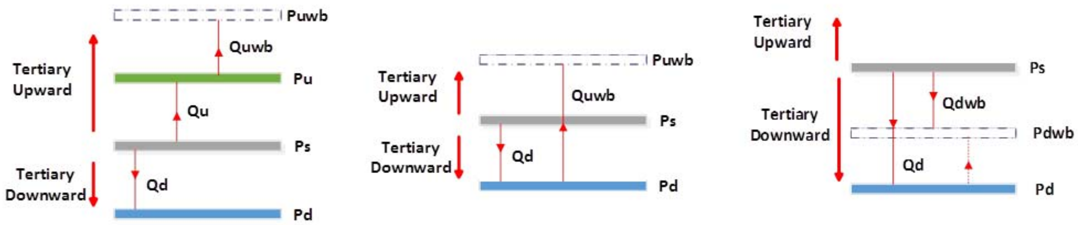

Fig. 2 – Different BBI impact scenarios

$$\boldsymbol{Profit\ of\ BBI = CPM - (VBI + CM)}\ \textbf{(3)}$$

- In the first scenario:

$$\boldsymbol{CPM(€) = (Puwb - Ps) * Quwb + (Ps - Pd) * Qd = (Puwb - Ps) * (Q + Qu) + (Ps - Pd) * Qd}\ \textbf{(4)}$$

$$\boldsymbol{Profit\ of\ BBI} = Qu * (Puwb - Pu) + Q * (Puwb - P)\ \textbf{\textit{(5)}}$$

- In the second scenario:

$$\boldsymbol{CPM = (Puwb - Ps) * Quwb = (Puwb - Ps) * (Q - Qd)}\quad \textbf{(6)}$$

$$\boldsymbol{Profit\ of\ BBI} = Q * (Puwb - P) - Qd * (Puwb - Pd)\ \textbf{(7)}$$

- In the third scenario:

$$\boldsymbol{CPM = (Ps - Pdwb) * Qdwb = (Ps - Pdwb) * (Qd - Q)}\ \textbf{(8)}$$

$$\boldsymbol{Profit\ of\ BBI} = Q * (Pdwb - P) - Qd * (Pdwb - Pd)\ \textbf{(9)}$$

5.2.CWM and Profit of BBE

After sell Portuguese tertiary reserve for the following hour, three distinguish situations could occur as represented in Fig 3 It will be done a simple description of the calculation method of CWM and Profit of BBE. The first scenario is the "classical" scenario: if it BBE did not occurred, it would be necessary mobilize (more) tertiary downward, se equation (11) and (12). In the second scenario, was mobilized tertiary upward, but if BBE did not occurred it would be necessary mobilize tertiary downward (Q > Qu), see equation (13) and (14). In third case was necessary mobilize tertiary upward but if BBE did not occurred, would not be necessary mobilize upward as much quantity as it was, see equation (15) and (16).

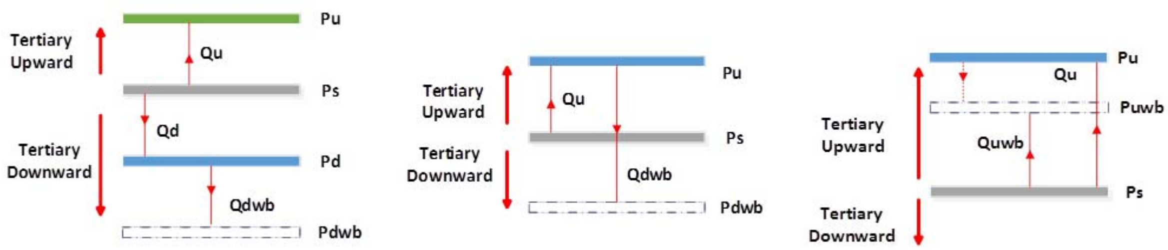

Fig. 3 - Different BBE impact scenarios

$$\boldsymbol{Profit\ of\ BBE = VBE - (CM - CWM)}\ \textbf{(10)}$$

- First scenario

$$\boldsymbol{CWM(€) = (Pu - Ps) * Qu + (Ps - Pdwb) * Qdwb = (Pu - Ps) * Qu + (Ps - Pdwb) * (Q + Qd)}\ \textbf{(11)}$$

$$\boxed{\boldsymbol{Profit\ of\ BBE} = Q * (P - Pdwb) + Qd * (Pd - Pdwb)\ \textbf{(12)}}$$

- Second Scenario

$$\boldsymbol{CWM(€) = (Ps - Pdwb) * (Q - Qu)}\ \textbf{(13)}$$

$$\boxed{\boldsymbol{Profit\ of\ BBE} = Q * (P - Pdwb) - Qu * (Pu - Pdwb)\ \textbf{(14)}}$$

- Third Scenario

$$\boldsymbol{CWM(€) = (Puwb - Ps) * (Qu - Q)}\ \textbf{(15)}$$

$$\boxed{\boldsymbol{Profit\ of\ BBE} = Q * (P - Puwb) - Qu * (Pu - Puwb)\ \textbf{(16)}}$$

6. RESULTS AND ANALYSIS

Firstly, a general (macro) analysis of the results obtained will be performed, with some previous conclusions and findings. In the second and third sub chapter l a more detailed analysis is performed, arranging the results in a different manner to enable two different types of reflections: i) a daily base analysis (short-term vision) where we can understand the behavior and the characteristics of both electrical systems during a complete market day; ii) a more long-term perspective were we can understand the evolution of this cross border exchanges during the complete period of analysis.

6.1. General Results

During this period, tertiary reserves were shared, BBA's, in 1038 hours. From the total of BBA's, 777 were BBI's and 260 were BBE's. From this previous information, it is possible take some previous conclusions:

<u>First conclusion</u>: The percentage of hours where BBA's occur: 1038/8760 ~12%. In 88 % of the time reserve regulation prices are very similar in both Iberian TSO's and it was not "potentially profitable" to buy/sell tertiary reserves in the remaining hours of the year. The prices and quantity of tertiary regulation reserves of the Iberian TSO's are directly influenced by climate conditions; both TSO's have in the portfolio a considerable quantity of renewable energy production, manly hydro and wind generation: When a "windy" day occurs in Portuguese territory, with a very large probability we will have a "windy" day in Spain. Moreover, when long periods of rain occur in Portugal (wet years), with a big probability they also occurred in Spain to. Additionally, both TSO's share 3 hydraulic interconnections: three rivers that are shared by both countries in the production of electricity (two in Douro river, and one in Tejo river). This fact adds to the understanding of the correlation between the characteristics of both TSOs.

<u>Second conclusion:</u> 75 % of BBA's are BBI's and only 25% are BBE's. Allegedly, the existence of more market players on the Spanish side, with greater relevance at production level, contributes to the improvement of the competitiveness and in turn generates tertiary reserve offers that are cheaper on the the Spanish side than on the Portuguese one.

6.2. Daily-based Analysis

In Fig. 3 it is possible to observe the total exchanges in an hourly basis. The cross-border exchanges occur more in the peak and off-peak periods. The amount of import and export and scenarios in the graph is noteworthy. The results of spot market in the Portuguese electrical system have an import trend during the off-peak period. The existence of a Nuclear Power Plant in the Spanish electrical system could help explain the existence of "cheaper" prices from REE side [10]. Despite the Portuguese tendency to import tertiary reserve regulation, the peak periods were the time at which the export tertiary reserve had more expression. One of the reasons is the existence of higher penetration of hydro generation from the Portuguese side, which helps to satisfy the consumption peak periods [11].

An interesting observation is the lack of business in the first hour, H, of each intraday market, IM, (H1, H5, H9, H12, H16, H22, respectively IM2, IM3, IM4, IM5, IM6 and IM7). This situation occurs because, in the significant majority of these periods, the Spanish TSO did not send offers to buy and/ sell tertiary reserve to the platform. In each intraday market, the suppliers could modify their tertiary offers. Probably, in the Spanish SO, the schedule to send offers to the exchange platform is, sometimes, very close to the schedule in which the suppliers have to tertiary offers/prices to the SO. A time incompatibility may happen, preventing the Spanish SO from providing timely offers to the platform.

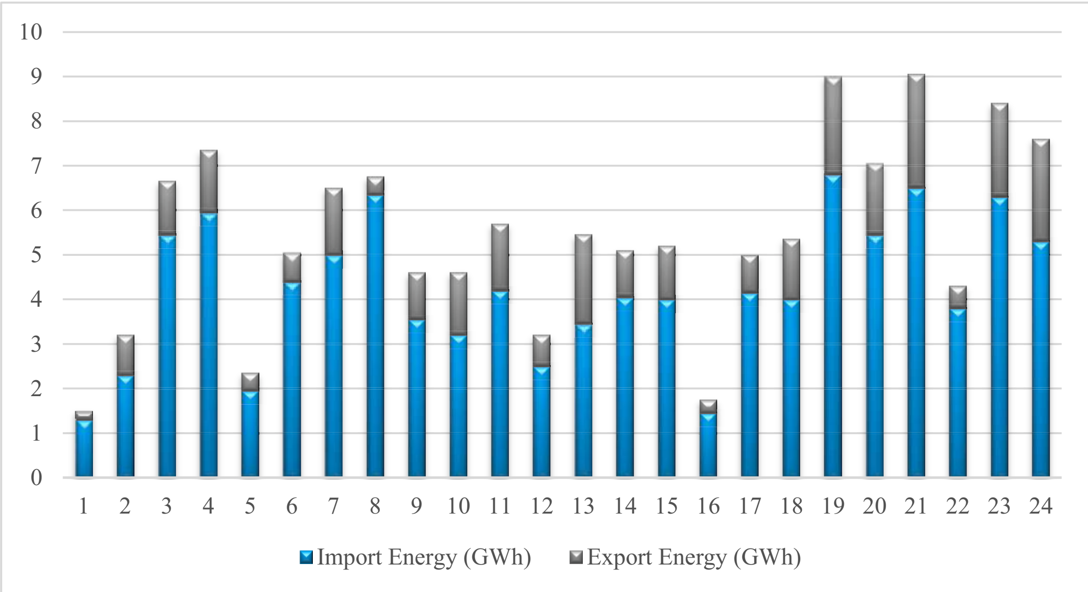

Fig. 4- Energy Trade at CBX

In Fig. 4 is possible to confirm some of the above considerations, in relation to the energy price: The off-peak period is where the average saving of **BBI**'s is bigger (than internally mobilized) and the peak periods is where the **BBE**'s are more profitable. These observations could be corroborated by the previous considerations about the Nuclear Power Plant in the Spanish Electrical System and the higher penetration of Hydro generation in the Portuguese electrical System.

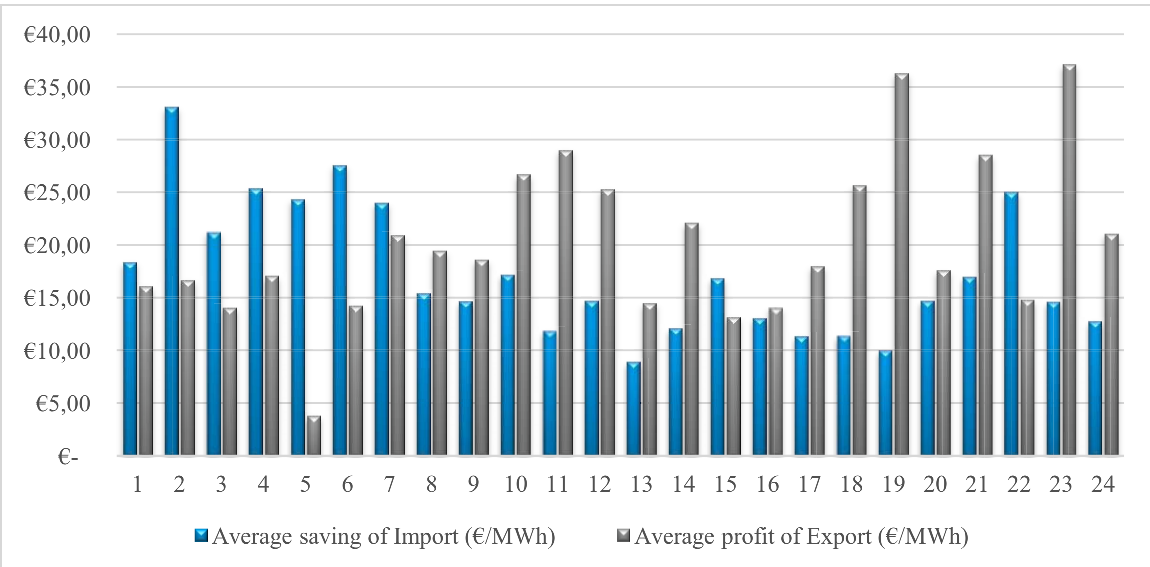

Fig. 5- Average Net Gain Transaction

6.3. Long-term Analysis

In Fig. 5, it is possible to observe the evolution of the BBA's during the first year of activity. There is a clear predominance of BBI in the beginning of the cross-border exchange of regulation reserve. In the first two months of activity, the balance was 92 % of BBI and 8 % of BBE. On the last two months of activity, there is an easily observable equilibrium between the amounts of transactions: 56 %, were BBE's and 44%, were BBI's. This tendency of equilibrium starts in the last six months, beginning in January. This equilibrium of transactions provides a hint about certain equilibrium prices and the proper functioning of the "market rules".

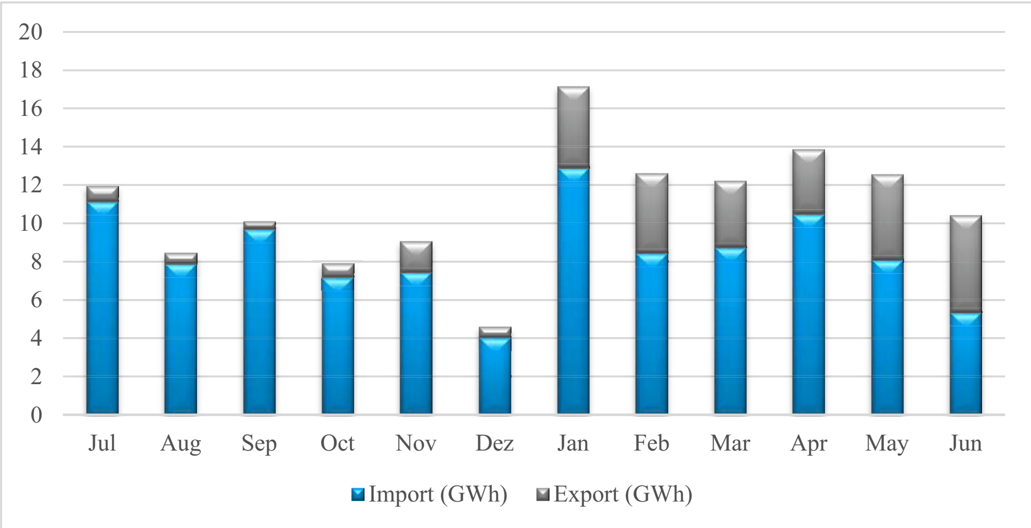

Fig. 6-Energy Trade

The Fig. 6, gives us a general perspective of the net gain transaction during the first year of activity. We can observe that the **BBE**'s gains have residual impact on the profits in the first half of the year and gain a relevant impact in the total profits, inclusively overcoming the net gain of the **BBI**'s in the last month. It is consistent with the volume of transactions effected both BBE's as BBI's

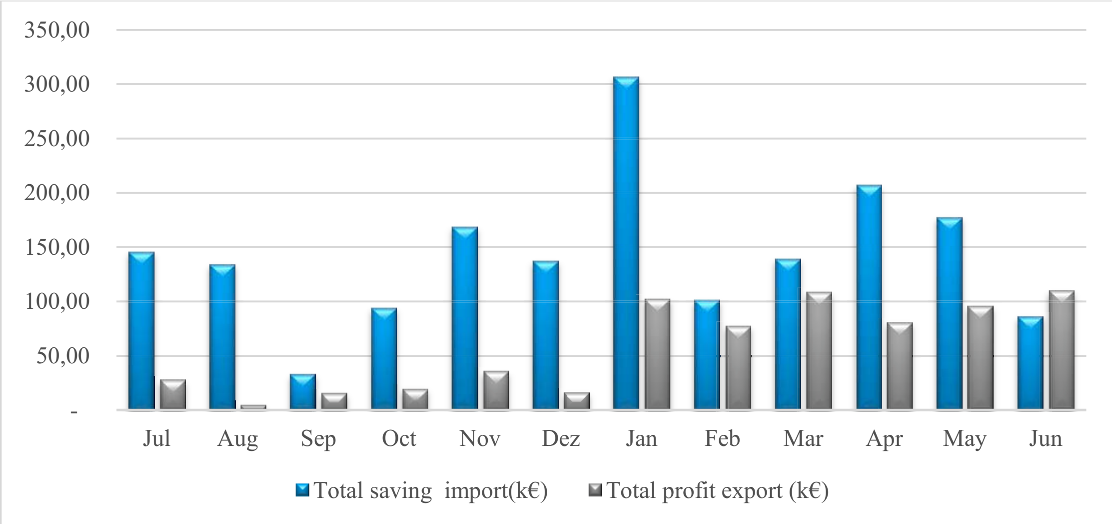

Fig. 7 - Total Net Gain Transaction

Table 1 and 2, gives the previous data in a condensed perspective:

Table 1-Total Values of Energy Traded

Total Energy Export	29,3 GW
Total Energy Import	101,5 GW
Total Energy Transaction	130,8 GW

Table 2-Total Economic Transactions

Total Profit Export	694.842,15 €
Total Saving Import	1.731.492,75 €
Total net Gain Transaction	2.426.334,90 €

7. CONCLUSIONS

The introduction of the Cross-border exchange mechanisms, and particularly of the reserve regulation, is new reality for both of the intervenient SOs in the Iberian Peninsula. Besides the economical advantages that were studied in this paper, the improvement of undeniable not only to the System Operators who have to deal with this new reality, but also to the market participants, especially suppliers, that will have to adapt their tertiary offers taking into account this new paradigm. What was a national market before tends to move towards a European dimension. Only one year of activity do not allow consistent conclusions about the implementation of this mechanism. However, gives good perspective and it was verified, in the Portuguese Electrical System, an economical gain. The introduction of more players in this sharing mechanism allows foreseeing an improvement of the economical results for all stakeholders

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The new Spanish self-consumption regulation

Vanessa Aragonés[1], Julián Barquín[1,*], Juan José Alba[1]

[1] *Endesa, Regulatory Affairs, Ribera del Loira 60, 28042 Madrid, Spain,*
[vanessa.aragones,julian.barquin]@enel.com,juan.alba@endesa.es
** Corresponding author*

ABSTRACT

The new Power Sector Law (Ley del Sector Eléctrico, LSE) 24/2013 regulates self-consumption facilities for the first time in Spain, and in particular PV panels for own domestic consumption. Specifics are set in the Royal Decree 900/2015 approved in October 9th, 2015. The purpose of this paper is twofold:

1. <u>To establish what features of access tariffs are important to ensure an economically efficient RES penetration and to enhance innovation in a fast changing field.</u> In fact, self-consumption impacts on energy generation, transmission and distribution losses and investment needs, ancillary services provision and power system control. Self-consumption is found be a cost-efficient alternative in some circumstances, but not in all of them.
2. <u>To analyze the recent regulation in the light of the findings above.</u> Regulations should align private incentives with societal goals. The analysis focuses in assessing if the approved regulation provides a level field in order to incentivize the most efficient development of renewable technologies. It also highlights some of its major drawbacks.

It is concluded that the self-consumption opens the possibility to a realistic alternative to grid supply. Therefore, energy prices and access tariffs should from now on to faithfully reflect actual supply costs, in order not to distort consumer incentives when choosing between distributed PV equipment (subject only to general taxation) and grid supply. Otherwise a gap can be split between social welfare and private incentives, incentivizing non-efficient investments and creating cross-subsidies on the way. On the other hand, the discussed regulation approved in Spain intends to "correct" the impact of taxes and levies unrelated to supply costs, by imposing these costs explicitly on loads, whether of self—consumers or not. This approach is found ultimately wanting, both because enforcement difficulties as, possibly more importantly, because artificially high electricity prices that distort optimal choice among energy carriers and hinder de-carbonization efforts. A stable and efficient regulation must be designed alongside an energy, preferably environmentally oriented, tax reform.

KEYWORDS: Self-consumption, electricity regulation, electricity distribution, electricity supply

Disclaimer: The opinions and positions expressed in this paper are the authors' personal ones. They are not necessarily those of Endesa or of the Enel Group.

1 INTRODUCTION

During the last years a radical reform of Spanish electricity regulation has been undertaken. Cornerstone of the reform is the new Ley del Sector Eléctrico 24/2013 (the Power Sector Law), approved by the Spanish Parliament as December 26th, 2013. The reform touches on a huge number of issues and, in particular and for the first time in Spain, it regulates self-consumption. As suggested, it should be stressed that this specific regulation should be viewed in the wider frame provided by the Power Sector Law.

The Power Sector Law does not set specific self-consumption regulations. Those have been recently laid out in the Royal Decree RD 900/2015 approved by the Government in October 9th, 2015. In the period since the Government announced its intent to regulate self-consumption (July 2013) until the approval of RD 900/2015, the Government announcements and the regulation drafts have been subject to intense public scrutiny. However the nature of the regulation has not always been faithfully portrayed. For instance, as discussed below, and whatever its possible shortcomings, RD 900/2015 does not tax PV generation but rather total consumer demand, which is consistent with the Power Sector Law philosophy.

The sequel of this paper is organized as follows. Next section describes current value and costs of technologies relevant in the self-consumption debate, that is, PV technologies. Section 3 reviews self-consumption regulation in a number of countries. Section 4 explains the current Spanish regulation. Finally, in section 5 we criticize the Spanish regulation and conclude.

2 SELF-CONSUMPTION, THE CHANGING CONSUMER ROLE AND THE VALUE OF DISTRIBUTED PV

Traditional power system regulation was predicated on a number of assumptions based on the technology then available. Energy was generated in huge central power plants and dispatched to final consumers. Consumers were captive, as electricity is an essential commodity that generally had not adequate substitutes. Therefore, it was possible to subject electricity to special taxation and to embed in the electricity price a number of costs not directly related to supply costs. Electricity consumption was positively correlated with the family income. Therefore, by including all these costs in the electricity bill, it was possible to argue that the traditional system did not significantly distort economic decisions, and was fiscally progressive as well as efficient.

Technological advances and decarbonisation goals require now to re-asses the traditional wisdom. On the one hand, having the right relative prices between electricity and other energy carriers is critical to decarbonize the economic system. Therefore, care must be taken when setting taxes and levies. Energy tax reform issues are thus of the greatest relevance. On the other hand, decarbonisation of the electricity sector is both an environmental need and a policy requirement, but it is also expensive. As a consequence, proper incentives for the deployment of the optimal decarbonized energy mix must be introduced. This in turn requires energy prices and grid tariffs that provide the right economic signals. This task might be daunting when distributed generation, now, and distributed storage, in the next future, are included in the analysis.

Efficient regulation must ensure a level playing field among all the possible technological choices. In particular, it must ensure a level playing field between distributed and utility-scale PV. This comparison can be particularly illuminating. This is because future generation costs, even if uncertain, will move in parallel for both technologies. It is also because most externalities (e.g. environmental or industrial policy ones) have the same value or at least very similar values for both choices. So, comparison is easier than for other technologies. Furthermore, regulation of distributed and utility-scale PV should be coherent. Coherence is much easier to check than in other cases and can be a powerful heuristic guide when valuing possible regulatory settings.

Most value differences between distributed and utility-scale PV can be traced down to the different impact on the grid and to the existence of economies of scale and system integration. The sequel of this section discusses these issues.

PV distributed generation, as compared to more centralized generation (including utility-scale PV) can decrease transmission and distribution costs, as long as the local production peak is correlated with the local consumption peak, which is likely for business but not for most residential consumers. Being more precise, transmission and distribution savings or additional costs may be either variable (mainly losses, roughly proportional to power flows squared) or fixed (mainly reinforcements and upgrading costs, roughly proportional to the maximum power flow). Fixed costs are an order of magnitude greater than variable ones. For low distributed PV penetration levels, PV up-flows are typically much smaller than load down-flows, so total distribution flows and losses are smaller. Peak load flow, assuming it happens during sunny hours, is likewise reduced or, if it happens during the night, not increased. So, in very rough terms, for low levels of distributed PV penetration, we should anticipate reduction of losses for residential PV and reduction of losses and grid investment requirements for business PV. On the other hand, were PV penetration is greater, distribution flows can increase, especially if load and generation peaks are not coincidental. Therefore, we should anticipate more losses and capital expenditure in the grid.

The penetration level at which there are no more T&D savings is very much dependent not only on the distributed PV generation profile, but also on the local demand profile, the existing network and regulatory constraints. However, they might possibly be smaller than often assumed. For instance, (MIT, 2015) reports[1] that, assuming US-like distribution regulation, total network costs remain almost constant until a PV penetration level in the 10-15% region is reached. For a 30% penetration total network costs increase up to 10% under the worst scenario. For EU-like distribution regulation, extra costs are much greater: they start growing for very low penetration levels, and may reach about 30% of extra-cost for a 30% PV penetration level[2]. Distributed energy storage might significantly change these figures. However, storage cost is currently still high, and its regulation non-existent or inappropriate, as discussed below.

Regarding economies of scale and system integration, distributed PV generation is generally less attractive than utility-scale PV generation. There are several reasons:

- There are significant economies of scale in utility scale PV as compared to small scale PV (e.g. the MIT report cited above reports 30% savings in investment costs for utility-scale PV versus small scale PV). The main reason is not the panel cost, that used to be the most important part of the PV facility cost, but the remaining costs that are an increasingly relevant fraction of the total cost (the so called balance of system costs) which exhibit strong scale economies. O&M unitary costs, although much less relevant, are also lower for utility-scale PV facilities.
- Utility-scale PV has less constraints related to both location and orientation. Distributed PV panels are typically installed on the buildings roofs, that are not optimally oriented[3], and where the line-of-sight might be obstructed. More importantly, insolation levels do change widely. For instance, Northern Spanish cities enjoy much lower insolation levels than huge Manchegan expanses[4].

Looking into the future, PV systems will be required to provide ancillary services, such as balancing and ramping. Actually, PV systems, being electronic devices, can be controlled in an extremely efficient way. In particular, they can always provide downwards reserve and, if generating below the maximum allowed by the resource, also upwards reserve. It is needed that they participate in the relevant flexibility markets and mechanisms, and that they are visible to the System Operator. These requirements, notwithstanding the future role of aggregators, are much easier to attain for utility scale than for small scale PV.

The final conclusion should not be so much to assume that utility-scale PV is less expensive than small scale PV, although this is nowadays the case. The real issue is that the cost and value of PV is strongly dependent of a number of circumstances, very difficult to be properly assessed by the Regulator. This is even more the case if non-economic reasons are considered (e.g. the customer desire to own and operate his own generating facility, beyond of economic savings and costs[5]).

However, it is a striking fact that it is often claimed that distributed PV can be deployed without subsidisation, whereas this is not generally the case with utility-scale PV. There are mainly two circumstances that can explain

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[1] pp. 161-163. The study is particularly relevant in the Spanish context, as the model used to simulate the network is quite similar to the one used by the Spanish regulator (the CNMC) and has been developed by the same team.

[2] Ibidem. This is because of the different network design and regulatory requirements in the EU and the USA.

[3] See, e.g., (A. Verso et al., 2015). It is shown, without being the authors' intent, that the impact of locating panels on gardens and roofs imply a 10% efficiency reduction with respect to optimized industrial facilities.

[4] E.g. 1,070 full load hours in Bilbao for a fixed optimized system as compared to 1,540 hours in La Roda, Albacete province, according PVGIS (http://re.jrc.ec.europa.eu/pvgis/).

[5] This desire to be independent of the utility is reported to have significant influence in some cases. In the literature is sometimes conflated with "empowerment" considerations, which is somewhat baffling for the authors, as PV costs and physical requirements prevent generalized adaptation by the poorest consumers.

these claims. The first circumstance is an inadequate design of the network tariff that pays what is essentially an option-like service (the possibility of drawing up to a certain power) in proportion to the actual energy taken from the grid (that is, the existence of volumetric network tariffs)[6]. The second circumstance (and the most relevant one in the Spanish context) is the very high level of taxes and levies that consumers pay for the energy they draw from the grid. Both circumstances may entail the existence of significant cross-subsidies towards distributed PV generation. Let us be more specific on both distortions:

1. Main grid cost driver is, with difference, the maximum power that consumers require during peak hours[7]. If the grid costs are charged as volumetric payments, by reducing consumption during off-peak hours, a consumer can reduce his grid payments without a parallel decrease of the grid cost he imposes, as his demand during peak hours does not change. The problem is compounded if net metering provisions are in place, as in this case total volumetric payments do further decrease without any change in the underlying grid costs. As distribution utilities are entitled to recover approved investments, any short fall from any customers category has to be compensated by other customers. In this case, customers without self-consumption facilities would see their grid tariffs increased over their fair level. As a consequence, a cross-subsidy from consumers without self-consumption facilities towards consumers with self-consumption facilities does arise. The relatively high tariffs paid by consumers without self-consumption facilities would presumably incentivize a number of them to become consumers with self-consumption facilities, further increasing grid costs to be burdened on the remaining customers without self-consumption facilities and further increasing incentives to leave this category. The phenomenon has been christened as the "death spiral" in the US debate.
2. Energy bought from retailers or in the wholesale market is charged with a number of taxes and levies. The structure in the Spanish case is detailed below, but it amounts to about half of the final electricity price for a domestic customer. In other countries, especially in the EU, taxes and levies can be also very high. Self-generated energy is effectively out of the market, and therefore can possibly avoid most of the taxes and levies. In the Spanish case, both electricity consumption from the grid and acquisition of distributed PV facilities are subject to the same VAT rate (21%), but all the remaining taxes and levies charged to electricity consumption are not applied to distributed PV equipment. As a consequence a similar phenomenon as the one above does arise: there is a cross-subsidy from consumers without self-consumption facilities to those with them, so long as costs financed by taxes and levies (mainly but not only renewable generation support and deficit annuities) still have to be addressed by electricity consumers. It is possibly worthwhile to point out that in this case the problem does not arise so much from the tariff structure (e.g. volumetric versus capacity charges) as from the existence of costs unrelated to supply.

In addition to creating cross-subsidies, in both cases incentives may be created in order to invest in relatively un-efficient PV generation instead of more efficient, large-scale alternatives.. Therefore, it is of the greatest importance that energy prices and regulated tariffs are not a distorting factor between utility scale and distributed PV.

3 SELF CONSUMPTION REGULATION IN EUROPE AND THE U.S.

Self-consumption at the residential or small business level is the focus of this paper. Being a relatively novel practice spawned by the recent and dramatic decrease of of PV panels costs, regulation is still in a somewhat experimental phase, and huge differences may be found among different jurisdictions. There is a general trend to evaluate in a more careful manner self-consumption benefits and costs to the systems, and set regulations accordingly. This trend is particularly clear in those systems enjoying a higher self-consumption penetration.

In Europe, the two countries with higher PV power are Germany and Italy. Self-consumption regulation in both countries, as well as in Portugal, is reviewed in this article. Regulation in the United States is also reviewed, although the situation greatly differs among the different states, as explained below.

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[6] This reason has been widely discussed, especially in the U.S. context, where the problem is compounded by not having hourly retail energy prices. In any case, it should be remembered that actual cost is mostly related to the possible maximum power, and not to the actual withdrawn energy.

[7] Precise figures depend of the grid and demand characteristics. However it is usually assumed that peak load is accountable for about 90% of the distribution costs.

In Germany, TSOs are entitled in principle to claim the surcharge for RES-E support (the so-called *EEG-Umlage*) from end consumers on self-generated electricity[8], that it is estimated to amount to 63.54 €/MWh in 2016. However, facilities having installed power less than 10 kWp and yearly generation below 10 kWh are exempted; whereas facilities over this threshold are transiently subject to a reduced EEG surcharge: they pay only 30% of the EEG-Umlage for self-consumption before 2016, 35% for self-consumption during 2016, and 40% for self-consumption after January 1st 2017. Energy injected in the grid is remunerated at 90% of the relevant Feed-in-Tariff for facilities below 100 kWp and, starting in January 2016, at wholesale price for those above. At the moment of writing the German Regulator (*BNetzA*) is carrying out a consultation on guidance documents (German Energy Blog, 2015).

In Italy self-consumption is charged in order to contribute to the system expenses. Facilities below 3 kWp are exempted, facilities between 3 and 20 kWp pay 30 €/yr, and facilities over 20 up to 500 kWp pay 50 €/year plus 1 €/kWp (GSE, 2015). Self-generation facilities are also entitled to compensation because of the energy injected into the grid. The compensation has two components: an "energy-component" proper, and a "services component". The energy component is based on the wholesale market value of the energy. Specifically, the market value of the injected energy is subtracted from the market value of the energy taken from the grid (the energy into the consumer's facility). The consumer pays the net value, if positive. Otherwise (that is, if the value of the injected energy is greater than the value of the energy taken from the grid), the consumer does not pay, and the remaining energy value is credited for the next year consumption. Regarding the "services component", it is intended to compensate for the services that the system saves because of the energy flowing into the network. It is computed from the "interchanged energy" (that is, the minimum of the injected energy and the energy taken from the grid) times an administrative price[9].

In Portugal self-consumers contribute with a charge from 3.4 €/kW per month (low voltage) to 4.8 €/kW per month (medium voltage). However, the charge is reduced if the penetration of self-consumption in the country is low (no charge for 10 years if penetration level is below 1%, 30% of the charges if the penetration is between 1 and 3%, 50% if above the 3%). Energy injected into the grid energy is valued at 90% of the average wholesale market price during the billing period, although the facility must be included in an administrative registry (Ministério do Ambiente, Ordenamento do Território e Energia , 2014).

In the United States most of the distributed PV deployment has taken place under net metering schemes, that is, an implicit recognition that the PV energy value is the retail electricity price. Nonetheless, the impact of tax credits regulation and other public instruments should not be minimized[10]. Utilities are generally bound by State regulators that set the relevant rules. Typically the customers receive a monthly credit for the excess generation at retail price that expires after a year.

As a consequence, distributed PV generation has been boosted in States enjoying net metering regulation, high retail tariffs and sunny weather, such as California (Borenstein, 2015), Hawaii (Coffman et al., 2016) or Arizona. With the increasing penetration has also come financial trouble to the involved utilities and public controversy. In particular, grid costs and other costs recovered through the grid charges are not necessarily recovered (however, the public policy costs recovered through the grid charges are typically lower than in Europe, which tends to reduce any distortion caused by self-consumption schemes). Anyway, the problem is compounded in the US context, as most of the electricity price is volumetric ($/kWh), capacity components are quite small or even zero (actually, $/kW charges are almost unheard of for residential users) as well as fixed components ($/month per connection point, very common but usually quite small). In some instances, utilities have asked the regulator (with variable success) to modify the tariffs, and quite often to substantially increase its fixed component (that is $/month).

As a consequence, U.S. discussion has moved towards alternatives to net metering schemes. Prominent among them is the so-called "Value of Solar" tariffs. General idea is to remunerate distributed PV generation according to the utility avoided cost. Irrespective of other reasons, the methodology has the advantage of identifying during the regulatory process the distributed PV contribution to the system and its impacts. It usually results in a significantly lower remuneration that the one under net metering tariffs. "Value of Solar" tariffs are in force in Austin Energy (a

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8 Sec. 61 EEG 2014.

9 It should be stressed that the description is a streamlined one, and that the Regulation should be read to get the details right.

10 Particularly relevant is the federal investment tax credit, for which residential solar is eligible. The credit amounts to a 30% of the investment (DSIRE, 2014), that has been recently extended up to 2019, starting to decrease since then onwards (see http://www.utilitydive.com/news/updated-congress-passes-11t-omnibus-spending-bill-with-solar-wind-tax-c/411115/). As in order to profit from the tax credit a huge enough tax base in needed, third party companies have an advantage that can use to offer residential customers net metering facilities under leasing agreements.

Texan utility) and under development in Minnesota (NREL, 2015). A Value of Solar tariff (grid-supply option) has been also recently approved for Hawaii (PUC Hawaii, 2015) after repelling previous Net Metering Schemes.

4 THE SPANISH SELF-CONSUMPTION DECREE

The new Power Sector Law (*Ley del Sector Eléctrico, LSE*) 24/2013 regulates for the first time self-consumption facilities, and in particular PV panels for own domestic consumption. Specific self-consumption regulation is developed in the Royal Decree 900/2015.

This discussion on the new regulation is structured along the following lines. Firstly, the access tariff is discussed. This is because the distortions introduced by the tariff are the basic reason why a specific regulation is required in the first place. Secondly, the "ideal" facility envisioned by the regulation is set and used in order to explain how the regulation intends to address the problem of distortions introduced by the tariff. Finally, simplified and transient schemes are explained. These schemes are the ones to be applied to most small facilities.

4.1 The access tariff: network tariffs and charges

It is impossible to sensibly discuss distributed generation and self-consumption regulation without a clear understanding of the access tariff structure, particularly for residential consumers and small business. Access tariffs include network tariffs and policy charges (mainly, but not only, renewable support charges and tariff deficit annuities). Network charges are arguably mainly capacity-based (that is, €/kW), whereas the case is less clear cut for the second concept[11]. The tariff structure is binomial. There are an energy term and a capacity term with values conditional to the voltage connection level, and the possibility of time-of-use tariffs (CNMC, 2014). On average, prior to August 2013[12] income for the capacity term was about 64% of total access tariff (50% for small domestic consumers). After that date, the capacity term means about 69% of the total access tariff (60% for small domestic customers).

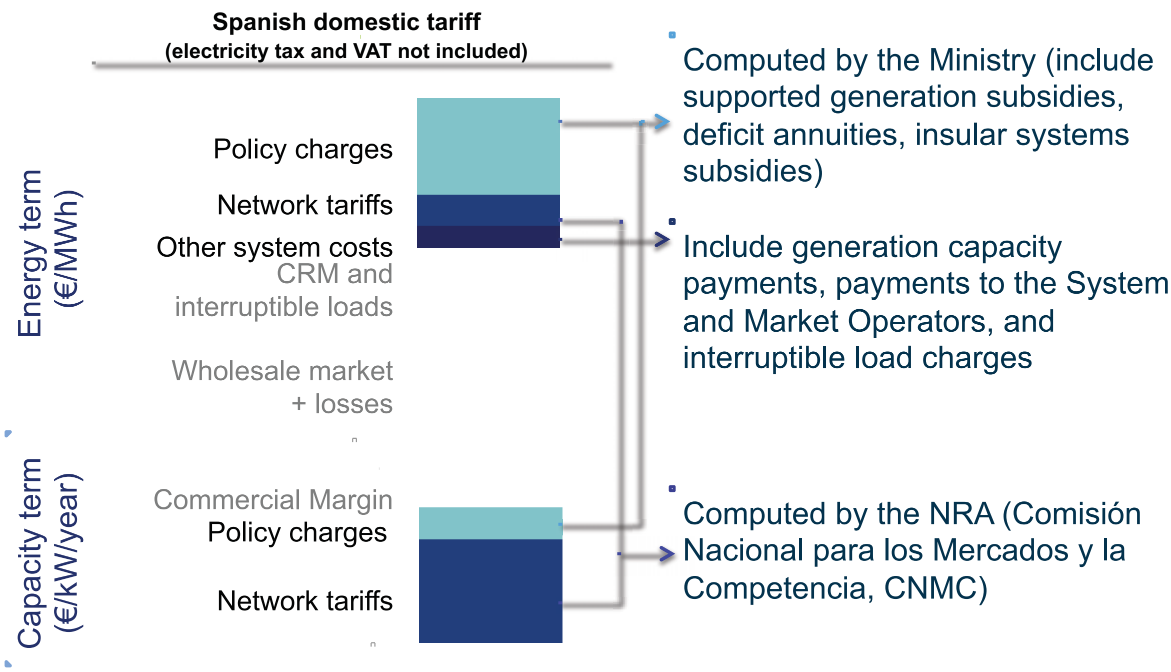

Figure 1: Domestic electricity bill breakdown.

11 It is not even clear cut whether only electricity consumption should pay for some of these charges, as opposed to payment by all energy consumption (e.g. transportation fuels) or the general State budget. See (Batlle, 2011).

12 When Ministerial Order ITC 1491/2013 was approved.

Fig. 1 shows the breakdown of a typical household bill. The bar height is proportional to the yearly payment in euros. Regulated payments are divided in network charges (dark blue), other system costs (black) and policy charges (light blue), as explained in the figure itself. It should be highlighted that most network costs are recovered through fixed (€/kW) charges and most policy charges through variable (€/kWh) charges. In addition, VAT (21% of the bill value) and the electricity special tax (an additional 6% of the bill value) are also charged as explicit taxes, but they are not shown in the figure.

Network tariffs are computed by the Sector Regulatory Authority (the Comisión Nacional de los Mercados y la Competencia, CNMC) according a public methodology[13]. Other system costs and policy charges are computed by the Ministry[14]. No methodology is currently publicly available.

The volumetric (energy) policy term may distort investment decisions in distributed generation[15] (Pérez-Arriaga et al., 2013). Absent specific regulation, from the consumer viewpoint, the economic value of self-generation is the energy saving (€/kWh) that includes, in addition to energy costs, the policy charges and some network costs. However, from the societal viewpoint, the value of self-generation is rather the system avoided cost, that is, energy and network variable costs, but not the other system costs and policy charges. A rigorous analysis must take into account the time varying energy cost as well as the PV facility production profile. If net[16] metering policies are in place the distortion might be greater than the one suggested by the figure, as PV production in possibly low price periods might be compensated by higher value energy consumption in high price periods[17].

Besides, it can be argued that distributed generation also benefits from the security of supply provided by traditional generation and embedded in the energy price, outside the access tariff. Arguing that consumers enjoying self-consumption facilities must shoulder systems' cost as all the remaining consumers[18], the LSE establishes the obligation of separated metering of consumption and own generation, and introduces a number of charges.

4.2 Spanish self-consumption regulation: the ideal case

Specifics are set in the Royal Decree 900/2015 approved in October 9th, 2015. The regulatory structure as envisioned in the Decree is represented in the Fig. 2 below.

[13] As a result, the fixed term is much more relevant than the variable term.

[14] Actually, the Ministry publishes the fixed and variable terms of the total tariff (network tariff plus charges). The charges can be inferred from this and the publicly available network tariff as published by the CNMC.

[15] The VAT would not distort investment between distributed and utility scale PV, since the same rate is applied to electricity consumption and to the sale of the equipment itself. The special electricity tax is, however, an additional distortion, although its magnitude is smaller than the ones discussed in the main text.

[16] Fixed network costs are not generally avoided unless the self-generation facility decreases the peak demand of the network, which is often unlikely to be the case as discussed in section 2.

[17] The ensuing distortion can be quantified by comparing two otherwise identical PV facilities, one selling to consumer through the market and the other one devoted to own production (e.g. same technologies, one sits inside the consumer's premises – to avoid additional network costs -and the other one inside). Generally both facilities can have substantially different rates of return because of the tariff structure.

[18] Specifically, the Law states that self-consumption facilities are obliged to finance the system costs and services as the remaining consumers ("[…] la ley establece la obligación de las instalaciones de autoconsumo de contribuir a la financiación de los costes y servicios del sistema en la misma cuantía que el resto de los consumidores", Law 24/2013, Preface).

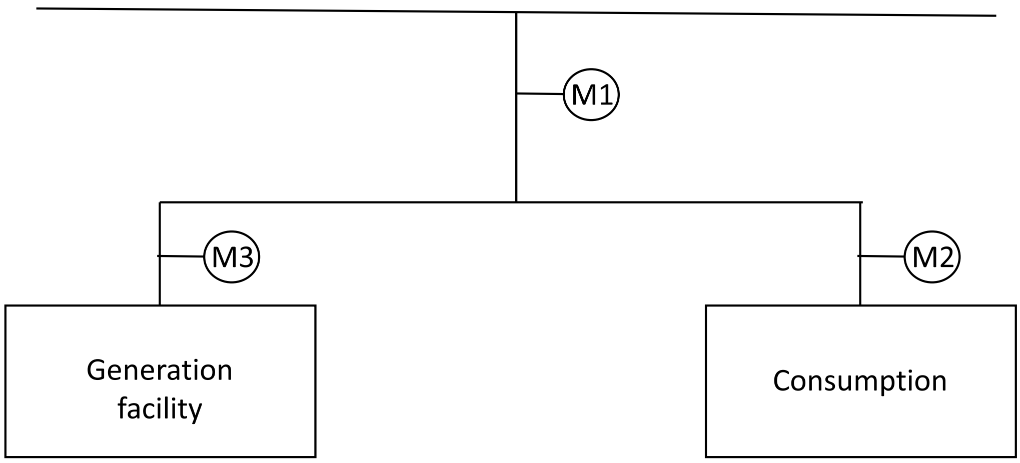

Figure 2: Self-consumption facility layout.

The generation facility (e.g. the PV panel) must be in a different circuit than the load[19]. Ideally, energy and power (that is, maximum hourly energy flow in a given period) are metered for the whole facility and for both generation and load circuits[20], although simplified metering procedures are set for small consumers (see below).

The Royal Decree fundamental idea is to charge network tariffs according to M1 readings and contract parameters, whereas the other system costs and, importantly, policy charges are charged according M2 (that is, consumption) readings and contract parameters. Readings and contract parameters include energy and power, as it is required by binomial tariffs. In other words, the generation facility is always exempted of charges. The Royal Decree does not discuss at length the rationale. However, it might possibly be argued that, from the network point of view, the whole of consumption and the generation facility is a single system and that, consequently, payments must only depend on what happens in the common connection point. On the other hand, system costs are mainly driven by consumers' needs (e.g. CRMs by reliability concerns) and policy costs are by its very nature a sort of quasi-tax, to be paid by all consumption.

By proceeding in this manner, the Royal Decree sets a level play field for self-generation technologies and the remaining large scale technologies, subject to some qualifications because of the large-scale generation network tariff and the special electricity tax, as well as the treatment of losses[21]. In particular, subject to the qualifications above, from the consumers' point of view, supply from generation within their own premises should be as valuable as supply from any outside but otherwise identical generator operating outside the consumers' premises.

The Decree goes on to define two different types of self-consumption facilities. Type 1 is addressed to small consumers, with a peak consumption power less than 100 kW, and where there is only a single legal person involved. Type 2 is for all consumers not covered by type 1 provisions. In particular, it may be the case than different legal persons own the load and the generation facility. This type might be of interest for CHP facilities, although the Spanish law allows for alternative CHP regulation. In both cases, the maximum power that the generation facility can provide must be less than the maximum consumption. Consumers of type 1 are not entitled to any kind of compensation because of excess energy flowing up to the network. On the other hand, consumers of type 2 might sell excess energy and even claim regulated additional remuneration in case of supported generation.

[19] If there are storage devices (e.g. batteries) they must be also installed in the generation circuit.

[20] One of the energy readings is redundant, but the three power readings are not so.

[21] M1 fixed (€/kW) charges are mostly those required by the consumption, as in self-consumption facilities generation peak power is unlikely to exceed demand peak power. So, incremental cost is low or zero. Variable network tariff depends on self-generation. All that should be compared with the large-scale generation network tariffs, established with a different methodology. Large-scale facilities are assumed to produce in the high voltage network, and a loss factor is applied when the wholesale price is charged to consumers. As discussed in section 2, loss factors related to distributed generation may be quite different, smaller or greater. The electricity tax has been commented above. However, overall, remaining distortions are small compared to the ones that the regulation intends to correct.

4.3 Simplified procedures and transient regulations

The Decree establishes that meter M2 is optional for all consumers with load less than 100 kW, but meter M3 should be installed. Again, the Royal Decree does not dwell on the rationale. However, it might possibly be argued that self-consumption generators are new elements to be added to existing facilities and, therefore, it makes sense to keep the existing facilities as they are, and to install anything new in the new generation circuit. In any case, and as a consequence, some quantities must be in some cases be computed or estimated rather than metered.

Being more specific, the energy that M2 should meter, and which is the basis on which other system costs and energy policy charges are applied, is the sum of the inflow energy metered by M1 plus the self-generation metered by M3 (see Fig. 2). Therefore, in the consumers' bill, energy (kWh) as metered by M1 will be charged with both network tariffs plus charges, as for a usual consumer without self-generation. Energy (kWh) measured by M3, assuming there is no hourly excess energy, will be subject to the charges (policy plus system costs). Total energy payments will be:

Energy_Payment	=	(Grid+Charges)*Energy_M1 + Charges*Energy_M3
	=	Grid*Energy_M1 + Charges*(Energy_M1 + Energy_M3)
	=	Grid*Energy_M1 + Charges*Energy_M2

Energy_M2 being the energy that a hypothetical M2 meter would measure. However, from the consumer viewpoint, it is as if he would continue paying the same bill as before (the one implied by the M1 reading) plus a new term related to the self-generation (the one based on M3 readings). This term is widely known as the "backup tariff" or, more colourfully, as the "Sun tax", although it does not pay a backup and it is, if anything, a consumption tax. The value is considerable (about 45 €/MWh for a domestic customer), as policy charges in the Spanish electricity bill are among the highest in Europe (Robinson, 2015; Eurelectric, 2014). It may be interesting to note that as charges are computed in an hourly energy balance, an hourly net metering is implicit. It means that if there is excess energy and consumption inside the same hour, both energies are balanced and is the net energy (excess or self-consumption) that is considered.

The fixed (€/kW) part of the payments should depend on the consumption contracted power, that must be estimated from the contractual parameters and readings of the circuits where M1 and M3 are placed. For small consumers, absent M2, and if the generation circuit only holds intermittent generation (that is, PV or wind generators, but not batteries) it is assumed that M2 power is just M1 power. The rational might be that M1 connection must be dimensioned in order to provide the peak demand, as intermittent generation might not be available during the peak demand periods. So, M1 and M2 connections need to have the same rating. In this case, the capacity payment is the same as for a consumer without self-generation:

Capacity_Payment	=	Grid*Power_M1 + Charges*Power_M2
	=	Grid*Power_M1 + Charges*Power_M1
	=	(Grid + Charges)*Power_M1

On the other hand, if non-intermittent elements are placed in the generation circuit, it is assumed that M2 power is the sum of M1 power plus M3 power. If storage (e.g. batteries) is involved, it might be argued that during peak hours the consumer would consume from the network as well as from the storage device that has been previously charged by the self-generation facility (during peak hours energy prices are usually high, so there is an incentive to avoid consumption from the grid). In this case, the capacity payment would be computed as

Capacity_Payment	=	Grid*Power_M1 + Charges*Power_M2
	=	Grid*Power_M1 + Charges*(Power_M1 + Power_M3)
	=	(Grid + Charges)*Power_M1 + Charges*Power_M3

That is, the consumer observes a bill with the fixed term computed as without self-generation capacity, plus an additional charge related to the storage capacity. The value, although not negligible (about 9 €/kW for a domestic customer) is possibly of less significance that the energy charge, as most policy charges and system costs are recovered as volumetric payments (€/kWh).

As commented above, the methodology for computing the charges is still to be approved. However, transitory values have already been approved. In particular, for small customers (tariff group 2.0), M1 total payments are the same for consumers with or without self-consumption facilities: 38.04 €/kW per year and 44.03 €/MWh as network access.

In addition, self-consumers would pay for M3 energy 46.75 €/MWh[22]. If batteries are installed there would be an additional M3 charge of 8.98 €/kW per year. The variable charge is reduced for customers in insular systems, as generation costs are generally higher in the islands. Specifically, customers in the Canary islands or the Ibiza-Formentera system are exempted from paying M3 energy, and customers in the islands of Mallorca or Menorca will only pay 17.34 €/MWh. Moreover, customers with less than 10 kW of contracted capacity are always exempted, whatever the location.

5 CONCLUSION

The approved self-consumption regulation is a very important step on putting distributed and large-scale generation on a level field. It is founded on a clear differentiation between network costs and other system charges. Large self-consumers (those of type 2) have also in principle access to RES deployment support as large-scale facilities. Small consumers are being incentivized by being exempted from charges.

Contrary to some widely made remarks the Decree does not introduce any taxation on distributed generation. Moreover, it foretells a methodology for defining other system costs and energy policy charges that will more clearly establish form the legal point of view the nature of the charges and the way of quantifying them. All these are positive developments not just for self-consumption but also for the system as a whole.

On the other hand, the Decree requires that the customers install metering equipment inside their premises and grant the right to inspect them to the distribution company. It is possible that this requirement causes considerable trouble. It is perhaps worth remembering that utilities' employees have no jurisdiction whatsoever inside particular premises, and certainly cannot enter if opposed by the owner. Summarizing, the enforcement of parts of this regulation is likely to be difficult if opposed by the owner of the generation facility. It is possibly because of this reason that fines[23] are established in case of breach.

Possibly more importantly, it does not address the lack of efficiency that the very high level of taxes and levies on electricity causes when compared with other energy carriers. It should be stressed that decarbonisation and security of supply can only be addressed by an increased electrification of the energy system. Instead of making sure that all levies and taxes are charged to the electricity demand, an effort should be made in order to decrease these parties, by efficiently sharing these costs among all energy users. That would decrease incentives for inefficient distributed generation, and consequently the enforcement effort and cost.

Finally, the Decree should also pave the way to effective innovation in distributed renewable generation. Today, self-consumption only seems to be efficient in specific circumstances (e.g. a large shop in a sunny city in which commercial opening time and PV production profile largely overlap). This might not be the case in the future, especially if PV generation is integrated in building materials at low incremental cost. In order both to incentivize these developments and to avoid premature deployment of inefficient alternatives, it is urgent to remove distortions from the electricity price.

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[22] The charge (46.75 €/MWh) is greater than the grid tariff (44.03 €/MWh) because of the treatment of system costs, that is, generation capacity payments, interruptible load payments, and System and Market Operator payments. A consumer enjoying the regulated energy tariff (the so-called PVPC) pays the wholesale market price and the system costs. Therefore system costs will be added on top of the 44.03 €/MWh in the energy part of the bill, up to the 46.75 €/MWh. A customer in the free market will agree a whole price with his supplier, who will presumably pass through these costs.

[23] The volume of the fines has also been wildly exaggerated. Even though reference is made to the law, that establishes maximum values for severe infringements that appear disproportionate, it must be noticed that Spanish legislation requires that fines are proportional to the economic impact of the infringement and revenues of the person being fined. Therefore, the values that are usually quoted are very far from what could be applied in practice.

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The impact of regulatory barriers to the advancement of renewable electricity consumption based on Spain : Royal Decree 900/2015

Rosa María Regueiro Ferreira[1], Paulino Montes-Solla[2], Alvaro Cabo Rodriguez[3], Julio Pombo Romero[4]

[1] *University of Coruna, Faculty of Economics, Campus de Elviña, A Coruña, and University Isabel I,Burgos, rosa.maria.regueiro.ferreira@udc.es*
[2] *University of Coruna, Faculty of Economics, Campus de Elviña, A Coruña, paulino.montes.solla@udc.es*
[3] *University of Coruna, Faculty of Economics, Campus de Elviña, A Coruña, alvarocr092@gmail.com*
[4] *University of Coruna, Faculty of Economics, Campus de Elviña, A Coruña, julio.pombo@udc.es*

ABSTRACT

The adoption of the legislation that regulates the house electricity consumption in Spain has given rise to a new controversy and generated more doubts whether, about whether it is possible to a sustainable energy future in Spain. With a reduced limit of 10 KW, all autoproduction of electricity from renewable basis that exceeds this limit, and that therefore suppose pour surplus to the electrical network, will have to face a financial penalty per KW, on the basis of the decompensation and unfair competition that eses discharges may pose in front of the traditional electric market in Spain.

Assess what differences are detected in Spain in relation to other countries in Europe that lead by betting on the house electricity consumption from more than 40 years ago; consider the strategies of the electricity companies that operate in these countries as well as determine if the house electricity consumption on the basis of renewable sources is a real distortion of the electrical system, are key variables to be analyzed in order to try to understand the real socio-economic scale of this new regulatory framework. It should be considered as part of a regulatory framework that emphasizes by its legal insecurity and in which the participation of consumers / small investors / autoproducers has always been relegated to the system background

KEYWORDS

Renewable energies, electric prices, photovoltaic energy, electricity. consumption

1. INTRODUCTION.

Since the 1979 oil crisis, most industrialized countries in the world, lacking of fossil energy resources, have tried to find solutions to external energy dependence, developing technologies with renewable alternatives to petroleum. These technologies with renewable energy sources are characterized by one much less than conventional fossil resources environmental impact. They are used for heat production (solar, biofuels, biomass, geothermal...) as electric (photovoltaic, wind, hydraulic,...).

In terms of power generation, from the end of the 19th century used natural, such as the wind and the water sources, but commercially only hydroelectric power had developed. Until the oil crisis of 1979, other renewable sources had a high cost for electricity generation that made them commercially unviable to compete with conventional sources. Currently, most industrialized countries are in full transformation in their energy models of power generation internalizing environmental costs that it generates,representing them move from an energy mix based on fossil fuels and emission of greenhouse gases to a mix focusing on renewable energy, without that it causes problems of instability between the generation and the consumption of electrical energy.

The European Union aware of the strategic character that possesses the power to social well-being, economic development and the structuring of Europe, at the end of the 1990s, they decided to promote a process of progressive liberalization of national energy markets through the adoption of Directive 96/92/ECwhich promulgates the creation of the internal market for electricity in the EU.This directive also indicates certain important measures for a proper functioning of the competition in national energy markets, such as among others the division of vertically integrated companies, the creation of a transport network manager and an independent system operator or third party access to the network. However, as indicated in the report itself ERGEG (2006) on the establishment of regional markets by the European Commission, the results of the application of this directive were not as satisfactory as expected.

2. THE RISE OF RENEWABLE ENERGY IN THE MIX OF ELECTRICITY GENERATION.

Currently, increasing energy demand worldwide because of the social and economic development of the industrial countries poses an environmental challenge in the production of electricity (ITC, 2008). All societies require energy services that meet the growing needs of the well-being of its citizens and the production processes of their companies.

The current boom in renewable energy around the world is mainly due to three factors:

a) the excessive foreign energy dependence of industrialized countries;

(b)the rising prices of fossil energy resources due to their depletion;

(c) and the emergence of numerous studies and recent reports that associate the role of greenhouse gases caused by fossil energy sources as the cause of current climate change.

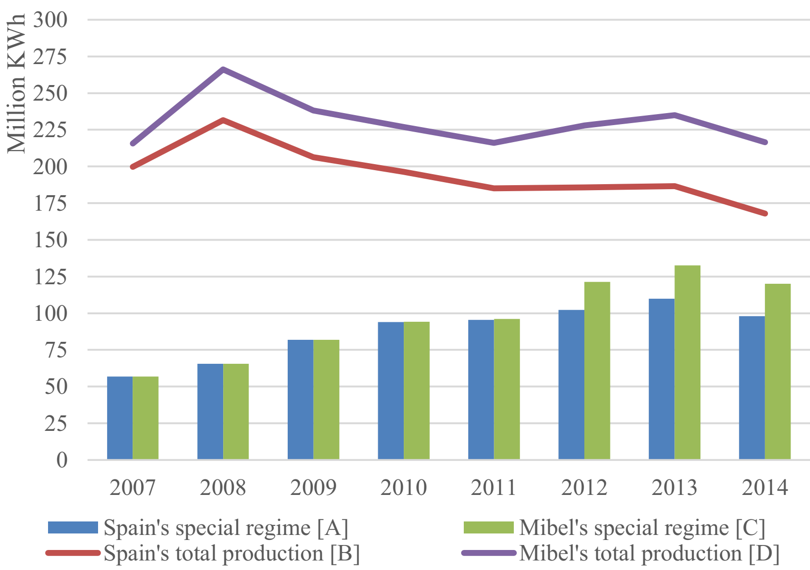
However, the initial investment to set up renewable energy sources has become the main obstacle for many countries, institutions and companies.This type of energy technologies are a long term investment, that although at first they are not profitable, its economic benefits and social futures makes it a good bet for the generation of energy in most industrialized countries.

Thus, since Europe accounts for about 15% of global energy consumption, the European Union (EU) is fostering policies promoting renewable energies that would limit the dependence on oil imports. Is why the EU has set as a aims to triple the current contribution of renewable energy (currently 6%, mainly hydro and biomass) to the energy mix, reaching 20% of the total energy consumption in 2020. There are substantial reports and studies from different agencies, both at the European level as national, with forecasts indicating a strong growth in the use of renewable energy sources in the medium term.

Another very important area of renewable energies at European level is the economico-laboral area, where at the end of 2006 they represented more than 300 thousand jobs and generated a turnover of EUR 30 billion a year, which placed it as a world leader in renewable technologies. There is an extensive literature and recent empirical studies on the big energy companies market power (Wolfram, 1998;) Borenstein and Bushnell, 1999; Wolfram, 1999; Wolak, 2000, 2003; Borenstein et al., 2002; Joskow and Kahn, 2002), however there were no studies on possible deliveries of market shares between the different companies in a dynamic energy market.

This process of strengthening this type of renewable energy can be seen in the following graph (Figure 1) from the market Iberian energy (MIBEL), showing a strong growth of special technologies (renewable) within the total of the energy mix. This growth is continuous since 2007 until sunset launched nationwide in 2013 of various regulatory changes that discourage this type of investment.

Figure 1: Annual evolution of special regime and total production in the Iberian Energy Market (2007-2014)

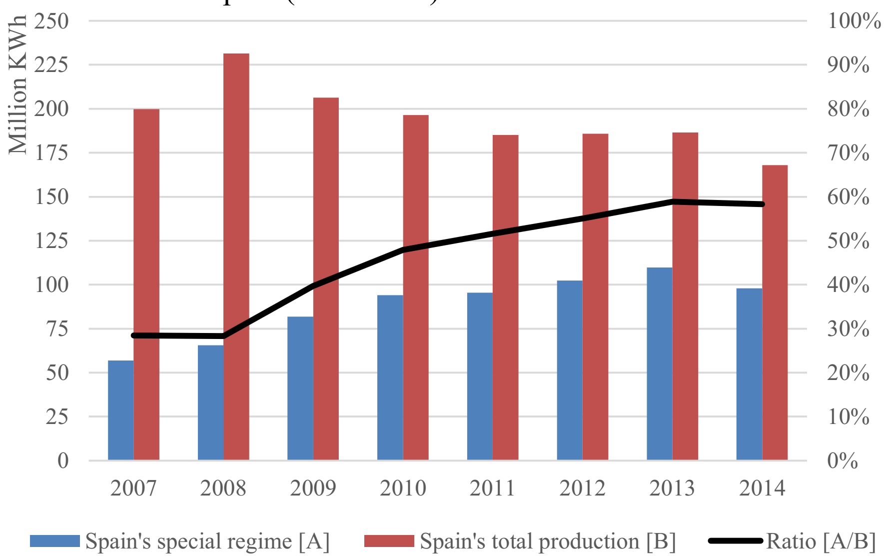


Source: Own elaboration from OMIE data (2007-2014)

Thus, at Spanish level prospects for the sector and for the Spanish renewable energy companies are good in the medium term, since they have a great experience in this type of projects. However, currently in Spain this sector has a strong legal uncertainty due to substantial policy changes, which limits investments that are tackled in this type of technology. Spain has gone from being a world leader in electricity production by energy renewables in 2006 to be currently losing the posts of head of these technologies because of lack of investment, both national and foreign, due to a changing regulatory, which generates legal insecurity to investors.

In the following graph (Figure 2) of the Spanish electrical market (ESM) can be seen a strong growth of the renewable technologies (or special regime) in the energy mix of the Spanish electrical market total. As you can see in the black line, the ratio that represents the energy production technologies of special regime on the total production of the energy mix has doubled in five years, from 30% in 2008 to 60% in 2013. However, commissioning 2013 of of various regulatory changes underway at the national level and legal uncertainty have discouraged investments in this type of renewable technologies which has caused the stagnation of the production.

Figure 2: Annual evolution of special regime production over total production in the Spain (2007-2014)



Source: Own elaboration from OMIE data (2007-2014)

3. POWER GENERATION FOR SELF-CONSUMPTION: GOOD EXAMPLES OF OTHER COUNTRIES

Opposite to the usual model of power generation where the flow is unidirectional and the generation and consumption are remote. The new model of distributed generation, and more specifically, the self-production, is closer to consumption points by generating centres reduced size, connected by small networks of distribution which avoid many current power losses. In this case, the consumers themselves (home, business or public body) through small generators, produce electricity that they need for their own consumption, or at least part of it.

This model has advantages and disadvantages regarding traditional electricity generation models. The first include the possibility of supply to areas where access to the distribution network cannot reach, increased efficiency of transmission and distribution networks and reduced energy losses. For another hand, between the disadvantages may be mentioned the loss of the centralized control system operator (that could be solved by intelligent networks) and increased costs in the lack of economies of scale.

The energy model of self-consumption that it’s regulated by the RD 900/2015, is a model that is already carrying out in other countries.

3.1. California (USA)

Since 1996, when California was the pioneer in the field of self-consumption and the net balance, has gradually opened this model to various technologies and consumption quotas. In that year he introduced the net balance for the solar photovoltaic and wind and a maximum limit for consumption of 0.5% from the tip of the system (currently is of 5.0%). Mainly it used the "net metering," which is a credit agreement between the company and the consumer-generator for excess electricity generated for 12 months and renewable installations for up to 1 MW. The intention is to promote the self-consumption by simplifying the regulatory system of own operator in order to achieve the goal of installing 12,000 MW in 2020 (currently is of 1,000 MW).

3.2. Germany

Consumption and net balance has been promoted in Germany through photovoltaic systems where consumers-generators received until the year 2012 a fee (Feed-in Tariff) for self-consumption and energy poured into the network. From this year, only the sales fee to net was maintained at the 10% for photovoltaic installations up to 10 kW, the powers that exceeding this rate receive fee for the 100% of the electricity fed into the grid.

3.3. Denmark

Although the regulation on self-consumption and net balance began in 2001 it was not until 2010 when it was regulated at domestic level or home, naming as system operator to the Energinet.dk. In this model are contemplated all renewable technologies except for geothermal. This made fall the collection of taxes and fees in the country, making the price of electricity for domestic consumers has passed from to be the most expensive in Europe in 2011 to drop drastically from there on. In addition, there are tax breaks for the installation of photovoltaic panels, minimizing barriers to initial investment. So, at the end of 2012, the installation of photovoltaic panels already exceeded the target set by the government for 2020, so that incentives to new facilities for self-consumption were reduced.

This international experience in regulating the self-consumption with net balance suggests the need for a regulatory framework that favors the self-consumption in Spain, as well as a price reduction and maintaining electrical costs and the income tax collection system.

4. THE NEW REGULATIONS ON SPANISH POWER CONSUMPTION

With the entry into force on 9 October 2015, of the Royal Decree 900/2015 that regulates electrical consumption in Spain has been a great controversy and has generated more doubts on distributed production and consumption and consequently sustainable energy future in Spain.

Thus, as indicated by numerous national and international organizations, the legislation that the Government has approved does not provide mechanisms that have been proven useful to boost the consumption of renewable sources such as the net balance or communities of consumers. As is explained in the previous section, the net balance is the most used in the reference countries where it is the main element to encourage consumption in households. Briefly, the net balance implies giving self-generating and surplus electricity when not needed at home and to return to system that same amount of energy when the installation is not in use. Far from affecting the manageability of the network, the net balance minimizes losses near the centres of production and consumption.

The fact that the regulation is especially burdensome with the type of facilities compatible with the consumption needs of the companies, deserves special mention. In addition to taxing the self-consumed power, referred to a draconian disciplinary regime whose fines start at €600,000 and can reach €60,000,000, a risk which deter the most enthusiastic.

On the other hand, exploitation formulas based on the collaborative economy, as communities of consumers, are expressly prohibited without further justification, which shows once again that the rule is not designed to boost consumption, as stated in the explanatory statement.

While elsewhere in developed countries consumption is consolidated and is a central aspect of environmental and energy policies in Spain, the small domestic and commercial generator-consumer will be forced to face tolls and administrative burdens, and even be forced to cede the power over not consuming traditional electric companies. In addition, the exemptions required for installations of less than 10 kW power auto-renewable power production are transitory, which at any time may be subject to assessment, which limits the only virtue of thestandard; the establishment of a clear and stable regulatory framework.

In short, Dr 900/2015 constitutes a rule unparalleled worldwide in terms of the regulation of the electric consumption of renewable sources because of its clear deterrent effect from the economic, legal and disciplinary point of view. In this way the new facilities in Spain are virtually stops despite the fall in prices and the abundance of resources, especially solar. The last of this regulation reasons are not the object of this paper, but in any case it is difficult to argue to be the momentum of consumption in particular and the promotion of an inclusive and sustainable energy model in particular.

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Financial Regulation of the Electricity Distributors: Necessity and Feasibility

Kesia Braga[1], Carlos Rufin[2], Ernani Torres[3], Roberto Brandão[4]

[1]*Federal University of Rio de Janeiro, Av. Pasteur 250, Rio de Janeiro, Brazil, kesiabraga@gmail.com*
[2]*Suffolk University, 8 Ashburton Place, Boston MA02018 USA, crufin@suffolk.edu*
[3]*Federal University of Rio de Janeiro, Av. Pasteur 250, Rio de Janeiro, Brazil, ernanit@hotmail.com*
[41]*Federal University of Rio de Janeiro, Av. Pasteur 250, Rio de Janeiro, Brazil robertobrandao@gmail.com*

ABSTRACT

Since the second half of the 1980s, when electric utilities were first privatized, the ability of the private sector to manage the supply of electricity with safety and quality has become a matter of high relevance for national governments wherever privatization has taken place. In this regard, the severe financial problems that have affected some electric utilities in different countries from time to time, have made it increasingly clear that exposure to financial risk can compromise a utility's ability to maintain service quality and continuity, and therefore that regulatory authorities should pay attention to the identification and control of utilities' financial risk exposure. This article aims to explore the factors that could contribute to the financial vulnerability of electricity distribution companies, in order to identify potential instruments for risk recognition and management. This study also proposes to examine possible regulatory policies for monitoring and addressing financial sustainability problems in these companies, a topic which has so far received scant attention in the international literature on electricity regulation. Lastly, this paper will evaluate the feasibility of regulating the financial exposure of electricity distributors.

KEYWORDS: Financial Regulation, Electricity Regulation, Distribution, Risk Management, Electricity Markets

1 INTRODUCTION

Nowadays, national regulators, experts and public entities in several countries have a growing interest in developing methodologies for economic and financial analysis of the electric distribution utilities. So far, some criteria, parameters and rules have been developed and applied to regulate the finances of the electricity sector. However, due to the high complexity of the matter, regulators are still improving their instruments and mechanisms of financial regulation. In this context, it is important to study the trends and evolution in this subject in order to contribute to the development of a highly relevant topic for regulatory policy.

The present study aims to analyze how the financial risks of the distribution segment of the electricity sector can affect operational indicators, such as the quality indexes of the services provided. The paper notes the increasing financial risk stemming from the regulatory reforms that have taken place in several countries. The recent transition from a "safe" model in terms of profitability and costs, where financial risk was largely borne by customers, to another in which the companies can incur in financial loss in a regulated environment suggests that attention to this new risky situation is needed for purposes of regulatory policy.

The financial nature of this situation suggests the use of financial supervision instruments, such as statistical models and accounting practices, that are widely used in other regulated sectors. The rate issue comes up as a central aspect, because the size of the distribution company revenues can be crucial to the success and failure of projects. Rates are the central mechanism to cover costs, ensuring the profitability of the invested capital, and enabling the quality of the operation together with the fulfilment of financial obligations.

The financial supervision of power distribution companies by regulators is a serious concern, especially in Brazil. Although there are a few recent experiences worldwide, this topic remains open to new contributions. This paper will present examples of financial regulation in the electricity sector, which can enrich the evaluation about the applicability of this policy.

This paper is divided into two main parts. The first one deals with the need for supervision of financial risk due to the transition to the price-cap model, mainly because of the financial losses it can generate for power distribution utilities. For this purpose, the paper compares the two main ratemaking models, rate-of-return and price-cap, highlighting their positive and negative aspects. In the second part, the paper analyzes the feasibility of financial supervision policy, reviewing three recent regulatory standards: that of the British regulator, the Office of Gas and Electric Markets (OFGEM), of the Ontario Energy Board (OEB) in Canada, and of the Brazilian regulator, the National Electric Energy Agency (ANEEL). The analysis focuses on the mechanisms and regulatory arrangements already developed.

2 RATEMAKING MODEL: IMPACT ON THE FINANCIAL RISK OF DISTRIBUTION COMPANIES

In the electricity sector, the ratemaking model has a fundamental role to guarantee moderate prices for users and profitability for investors. The process of liberalization in the 1980s was decisive with the transition from the cost of service model to the incentive regulation model. This transition has brought considerable changes for the sector and raises lots of questions about how the ratemaking model change will affect the risks of electric power distributors.

2.1 Definition and Analysis: Rate of Return and Price-cap Models

The principle of rate of return regulation, also referred as cost of service, was traditionally applied in sectors characterized by natural monopoly, such as the segment of electric power distribution, and its use was generalized through the American experience of regulation of public services.

The tariff based on the cost of service model is calculated to compensate the company for the full cost of the service, and ensure an attractive rate of return for the investor. The final tariff should cover the fixed and variable costs, including also the rate of remuneration for the investor. Another important observation is that this rate of return usually is negotiated between the two parties involved in the concession, the regulators and investors, to ensure an attractive return rate of investment for shareholders without raising excessively the final prices for the customers. This can be done through regulatory process, e.g. in the United States, or fixed by law, e.g. in Brazil.

The tariff based on the cost of service was criticized in several aspects, mainly the difficulty of determining a base value for the investment[1] used to calculate the total return to the shareholders, and which can be estimated in various ways. In addition, the use of "historical cost"[2] as an estimate for future costs is not the best approach, as a simple and general pricing practice. The problems of this method worsened in the period of hyperinflation in Brazil, where the real price of the electricity service was distorted by the application of several stabilization plans in the country[3]. Another motive of criticisms were the undesirable side effects on the electricity sector, especially the stimulus to inefficiency, since there is no incentive to reduce costs or improve the productivity and quality because the tariff always covers the costs and ensures an attractive remuneration rate. It is worth mentioning that the implementation of this ratemaking model also raised regulatory costs because of the great asymmetry of information between the regulated companies and the regulator[4].

The regulatory model for cost of service regulation presented signals of exhaustion with the deterioration of services and disincentive to investments mentioned above[5]. The model's deficiencies, in the context of economic

[1] Araújo, 2001.
[2] Includes the total investment effectively realized in the past (Araújo, 2001).
[3] Leite, 2007.
[4] Armstrong et.al (1994).
[5] As an example, we can mention the electricity crisis that occurred between 2001 and 2002, reflecting the lack of investment and mismanagement of the Brazilian electric sector planning (Cuberos, 2008).

liberalization, triggered a movement for regulatory reform of the public utilities during the 1980s and 90s. In the second half of the 90s, the Brazilian government implemented a new ratemaking model, the “law of concessions of public services (Normative Instruction 8987/1995)”, that guided the transition of the cost of service model to a price-cap model. The reforms aimed to reduce the problems of asymmetric information, to make the companies increase their levels of efficiency, to generate new investment, and to simplify the pricing structure.

The new method, price-cap tariff, establishes limits to the average prices of the firm. The general adjustment formula is: DCP = RPI-X + Y, where DCP is the rate of adjustment of the price-cap, RPI is the Retail Price Index, X is the productivity factor and Y a variable that considers the pass-through of unexpected costs to consumers. This method simplifies the tariff adjustment, stimulates productivity gains of efficiency and motivates investment[6]. This mechanism is considered more stable because it allows rate reviews at fixed intervals of time, in order to verify the economic and financial balance of the concession and, eventually, to adapt rates to unforeseen contingencies.

The goal of the rate review is to set rates that are consistent with the costs of distribution and suitable with a fair return on investments[7], through the calculation of a Required Revenue[8]. The estimation of the X factor, which takes into account an estimate of the productivity gains in the following years of the cycle, is also a step for rate setting. Therefore, there is a significant incentive for the distributors to reduce the costs, since between two cycle reviews the companies can take advantage of the cost reductions. On the other hand, if the difference between operational costs defined in the review and the effective one that the company can achieve is negative, there will be a negative financial impact for the distributor.

The main criticism of this price cap method is the possibility of under-investment in customer-related service. The improvement of this type of service can require higher costs that may not necessarily have some return for investors, through the pass-through to consumers or in another way. Hence, the price cap model must have a strong regulatory apparatus that reinforces the desirable levels of investment and maintains satisfactory quality of the services.

A deeper analysis of the distribution segment shows that the transition between a ratemaking method that guarantees full coverage of costs and attractive rate of return, and a model based on incentives, brought new risks to the distributors. With the regulatory change, it is possible that the investments made by distributors may not have a satisfactory return, leading to financial losses. The cost pass-through to consumers in price-cap method does not contemplate mismanagement and inefficiency of the service, which can also result in financial losses mainly through regulatory penalties.[9]

In Brazil, the risk that most affects a distribution company's financial sustainability is contracting for long-term energy supply through auctions. If the company contracts power above the level necessary to fulfill its demand, it bears the excess cost, because there is a limit to the pass-through of those costs to consumers to encourage distributors to manage the energy market in an efficient way. Another significant risk in Brazil is the hydrological risk, because the Brazilian electricity system is hydro-based, creating the risk of increasing costs of energy in a drought scenario.

For the utilities in the United States, the report of Binz et al. (2012) offers an alarming analysis of these companies. The authors found a decline in credit quality and financial flexibility of the electric utilities over the past 40 years, especially in the last decade, in which no utility obtained an AAA rating and there was a large decline in the number of companies with AA rating. This fall in credit quality can be an important signal of the need to consider financial risk. Some analysts also point out that the credit profile of the utilities could decline even more due to the lack of operating cash flow in those companies to meet the investment needs of the sector.

The regulators must avoid a situation in which the only remaining options are the bankruptcy of a distribution company, or the cessation of the regulatory principles of prudence and reasonable cost recovery to rescue the company, putting a cost burden on consumers. This scenario could be avoided by considering financial aspects in the regulation of the sector. To analyze the feasibility of a regulatory policy of financial supervision for electric power distributors, we studied similar regulations already in course worldwide, as shown in the next section.

[6] As we will explain later, the cost reduction is an incentive mainly in the gap between two tariff reviews, but there are some cases where this method is not effective in improving investments.

[7] The proper determination of the return of the capital to ensure attractiveness to investors, is made by using the Weighted Average Cost of Capital (WACC) (IPEA, 2006).

[8] That is, compatible with efficient operating costs and return on invested capital (Cuberos, 2008).

[9] The revenues resulting from the application of penalties are applied to rate reductions (Cuberos, 2008).

3 FINANCIAL REGULATION OF DISTRIBUTION COMPANIES AROUND THE WORLD

Three main recent cases of financial regulation of electricity distributors were analyzed: that of the Ontario Energy Board, the British Office of Gas and Electric Markets (OFGEM), and the Brazilian Electricity Regulatory Agency (ANEEL).

3.1 Regulatory Guidelines: Office of Gas and Electric Markets and the Ontario Energy Board

OFGEM[10] has established financial regulation rules and strategies for the electricity sector, and especially regarding the financial health of distribution utilities. The standards were designed to reduce the financial risks for the utilities, while assuring the continuity of service to consumers. The function of the agency in this regard is mainly to guarantee that the distribution companies can fulfill the requirements established by law or contract. The responsibility for the financial integrity of the distributor is a responsibility of the shareholders of the company.

It is important to highlight the conditions of "financial delimitation" included in the regulatory arrangements of OFGEM. The purpose of this regulation is to assure that the assets, cash flows and other financial resources of the utilities are sufficient to meet the needs of the companies, with sufficient resources to provide the service properly and efficiently, so that no such resources are used for other purposes.

In this regulatory framework, the utilities has the obligation to provide to OFGEM financial information, and as the first signs of financial problems appear, OFGEM can choose appropriate actions to address the situation. In this scenario, the regulator will analyze the reasons that led to the financial problems, also checking if the company was operating efficiently and cost-effectively. After identifying the causes of the problems, there are a number of steps[11] to remedy the situation. The most important one is to block the company's cash reserves in circumstances of financial concern, reaffirming the commitment to maintenance and service to consumers above the interests of lenders and shareholders.

The Ontario Energy Board (OEB)[12] uses an incentive policy[13] for utilities in the province of Ontario in Canada. The regulation by incentives works according to a scorecard for the Ontario electricity distributors, which includes various aspects of the performance of the utilities, generating evaluations and comparisons between companies, including financial aspects. The purpose of the regulator is to inspect and maintain the financial sustainability of the companies, with the use of financial accounting parameters, such as current ratio, debt service coverage, interest coverage, costs of operation, maintenance and administration costs by customer, and return on equity. The methodology of calculation [14] was developed in the form of financial ratios: liquidity (current ratio), leverage (short-and long-term debt) and profitability (included in the rate review and actually realized).

3.2 The Financial Regulation in the Brazilian Electricity Sector – Instruments and Applications

The Brazilian Electricity Regulatory Agency (ANEEL), stated since 2007[15] the development of regulatory rules for financial supervision of distribution companies. The distribution sector operates in the form of a natural monopoly, and its efficiency is conducted and organized by the standards and parameters set by ANEEL. ANEEL's Superintendency of Financial Supervision (SFF) has a consolidated role in gathering economic financial information from distributors.

A distribution company is responsible for the quality and continuity of the supply of electricity, and the renovation and expansion of its assets. This requires making investments (capital expenditures-CAPEX) and incurring in operating expenses (Operating Expenditures-OPEX). The company must also cover other obligations, such as debt service payment to lenders and financial institutions, taxes and the return on equity capital and dividends. If it

[10] According to OFGEM's policy document, the main goal of the Agency is to protect the interests of consumers of gas and electricity, for if the regulated companies experience financial problems that can impact the continuity and quality of service, OFGEM would be held responsible (Ofgem, 2009).
[11] A detailed explanation of those steps can be found in Ofgem (2008, 2009).
[12] The Ontario Energy Board regulates the distribution of electricity in the province of Ontario, with the goal of combining the interests of distributors and consumers. The new regulation, based on the performance of companies, aims to stimulate the development, productivity and innovation in the sector (Report of the Ontario Energy Board, 2012).
[13] *Ontario Energy Board* (2012).
[14] For more details, consult *Ontario Energy Board* (2014).
[15] Technical note nº 380/2007-SFF/ANEEL.

cannot generate funds to honor all its commitments, the company requires external resources, which can imply increasing in its leverage.

The economic and financial dimension of the concession is directly related to the operational dimension. The triggering event was the “Grupo Rede” collapse when the energy supply was under threat in seven Brazilian States.[16] This was an inflection point in the attitude of the agency towards the companies. After this episode, a sector diagnosis organized by the Agency indicated that a number of companies were presenting low financial results, motivating the improvement of the monitoring mechanisms of the economic and financial status of the distribution companies. It is important to emphasize that the systemic risk of the debt default of company causes problems along all the production chain, reaching the financial viability of the business, as in the case of the “Grupo Rede”, where several companies needed the intervention of ANEEL. This example shows the strict relationship between the operation and the finances of the company, althought the operational dimension of the concessionaires is regulated in detail, while the financial regulation is poorly developed.

To guarantee the security and quality of the supply, the regulator should monitor the financial situation of the concessionaires, such as its ability to keep up with growing demand, expand their capacity to maintain the operation of the service, and still honor their commitments and applicable taxes, signaling its financial health. As an example of what is done in other regulated sectors of the economy, ANEEL intends to use accounting and financial methodologies to form a framework applicable to risk supervision of companies in the distribution segment, similar to what the national supplementary health insurance agency (ANS) does and in the banking sector. The ANS, through economic and financial indicators, seeks to identify if supplementary health insurers show evidence of transient or structural difficulty, especially with regard to the question of indebtedness. In the banking sector, where systemic risk can propagate the effects of insolvency of one or some institutions throughout the financial system, the financial supervision of banks and financial institutions is a central part of the regulatory apparatus. Prudential[17] regulation is widely used in the financial sector. It has specific preventive rules that guide the behavior of the agents and ensures that the information flow to monitor the situation, preserving the solvency of the institutions. This regulation applies leverage ratios and liquidity ratios, and limits the performance of banks regarding the composition of their asset portfolio, among others.

3.2.1 ANEEL’s New Economic and Financial Criteria for Electricity Distributors

Evolving through the learning promoted by ANEEL, the Ministry of Mines and Energy (MME) may extend the concession of public utilities for 30 years, provided some requirements defined by ANEEL are met, among which the economic and financial sustainability of the companies. In this scenario, the utilities hold the responsibility to preserve the sustainability of the business, the management of resources, the debt levels, the investment levels, and the financial obligations.

Regarding the economic-financial analysis, ANEEL has established economic and financial standards to be met in the first five years of the concession, based on the following milestones: I. investment to replace depreciated assets; II. investment expansion and improvement of quality of service; III. payment of interest on debt; IV. working capital; V. taxes on profit; VI. remuneration of corporate capital, and in certain cases, VII. Amortization of principal, among other obligations.

It was defined by decree[18] that in the first and second years of a concession, the utilities must achieve positive EBITDA, that is, recurrent expenditures below operating income; in the third year, a positive cash flow after deduction of investment, that is, part of the company's revenue should at least restore the CAPEX; and at the end of fifth year, positive cash flow after deduction of investment and cost of debt.

3.2.2 Regulatory Response to Non-compliance with the Parameters of Sustainability

The innovation in applying penalties is the understanding that the imposition of fines is not a proper way to treat distribution companies with financial difficulties. The penalties could push those companies to increase their leverage and the level of risk assessed by investors, that could led this companies to a meet a worse situation. This

[16]Ozorio (2011) has identified, through the analysis of the results from 2006 to 2011 using accounting and financial methods, that Grupo Rede’s companies presented problematic indicators, such as worsening operating margins, high risk of default due to an unsatisfactory operational results, and high indebtedness. This was confirmed with the crisis of the group in 2012, where eight companies required intervention from Aneel.

[17] A second type of regulation concerns systemic risk, to prevent the occurrence of events that spread throughout the economic system, and thus avoid financial crises. There is also behavioral regulation, i.e. normative rules to discipline the practices adopted by market agents in relation to their competitors and consumers.

[18] Decree nº 8.461, 2015.

innovation is associated with what is called Prudential Regulation, increasing the involvement of controlling shareholders to meet the minimum parameters defined by the regulator. If this clause is refused, the participation of the same investor in another project in electricity market will be limited.

In addition, if the distributor does not reach the minimum standards of sustainability, the new policy establishes that the distribution of dividends or interest on equity capital will not be allowed until the regularization of the utility's finances. Finally, in the case of persistent difficulties and non-achievement of the goals after five years, the concession can be canceled.

4 CONCLUSION

The financial supervision of electricity distribution companies is still at an early stage in academic centers, in government agencies and among international regulators. The need for financial risk management arises from the current tariff structure that raised the exposure of utilities to financial losses. In Brazil, the collapse of one of the largest distribution energy holdings in the country, caused by a gradual financial deterioration, led the regulator to adopt extreme measures to mitigate the social damages. After this emblematic case in the Brazilian electricity sector, new financial problems were identified in other companies, indicating the need of a monitoring framework for the electricity sector. Financial regulation, already used successfully in other regulated sectors, could be applied to the electricity sector for financial supervision of the electricity distributors, with the adoption of prudential practices to prevent future supply crises created by financial mismanagement.

Financial regulation is an important topic worldwide, but there is not a standard way of its application, even when taking into account possible variation in objectives. The use of accounting and statistical instruments is important to the financial supervision of companies, as already being developed by OFGEM, OEB and ANEEL, to encourage the financial health of the companies and to ensure the service continuity and quality. Specifically, in the case of ANEEL, the regulation also has a focus on anticipating the detection of any sign of financial difficulties of companies and to act fast in these cases.

The general conclusion is that financial regulation is a highly relevant matter and has to be implemented in the electricity sector to avoid social losses caused by the concessionaires' mismanagement.

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Price Coupling of Regions: What changed in Western Europe?

Nuno Carvalho Figueiredo[1,2], Patrícia Pereira da Silva[1, 2, 3]

[1] *EfS Initiative, University of Coimbra, Sustainable Energy Systems – MIT-P, Coimbra, Portugal, nuno.figueiredo@portugen.com*
[2] *INESCC, Coimbra, Portugal*
[3] *Faculty of Economics, University of Coimbra, Coimbra, Portugal*

ABSTRACT

The initiative denominated Price Coupling of Regions (PCR) aims to join existing Regional Electricity Markets through the market coupling mechanism. It was launched at the Florence Regulatory Forum in 2009 by three power exchanges: Nordpool, EPEX and MIBEL. In the meantime, additional members joined the initiative, such as APX-Endex, Belpex and GME, reaching 2860 TWh/year of potential electricity trading. In May 2014, market coupling between Iberia, Central West Europe and Nordpool was achieved, what was one of the main objectives of the PCR initiative.
In this framework, this paper aims to assess the effect observed with the implementation of the PCR through the scrutiny of spot price differences. We analyse the market splitting occurrence both before and after the introduction of the PCR.
The evaluation of hourly data starting on the 1st of January 2013 until the 20th of October 2015 shows a slight improvement of electricity market integration between Spain and France, albeit without a noticeable effect between France and Germany or Germany and Denmark.

KEYWORDS: Price Coupling of Regions; Electricity Market Integration; Market Splitting Hours Share

1 INTRODUCTION

The European Internal Electricity Market (IEM) is one of the fundamental objectives of the European Union (EU), aiming to achieve market efficiency and security of supply. Throughout the past 25 years electricity markets in Europe some achievements are to be noted: (i) some degree of market unbundling was achieved in most of the member states; (ii) creation of wholesale and retail markets; (iii) cross-border trading between regions (Glachant & Ruester, 2014).

Cross-border trading of electricity was achieved in several European regions by using explicit or implicit auctioning mechanisms. The first successful European region to achieve stable cross-border trading was the Nordic, which was established in 1996 by Norway and Sweden, followed by Finland in 1998 and Denmark in 2000 (West Denmark – DK1 and East Denmark – DK2) forming the Nord Pool. In the Nord Pool market splitting is implemented, which is an implicit auctioning with a single power exchange. A similar mechanism was implemented in Iberia, joining the Portuguese (OMIE PT) and the Spanish (OMIE ES) electricity markets (Figueiredo & Silva, 2015). To accommodate different power exchanges, another implicit auctioning mechanism, the market coupling, was implemented between the Belgian, the French and the Dutch electricity markets (BPX, Powernext and APX, respectively) in November 2006, forming the so-called Trilateral Market Coupling (TLC) (Powernext, 2013) and in November 2010 extended to Germany and Luxembourg (both EEX) obtaining the Central West European (CWE) Regional Electricity Market (REM). These REMs are part of the Electricity Regional Initiative launched in 2006 by the European Regulators Group for Electricity and Gas as an intermediate step for the European IEM (Karova, 2011; Meeus & Belmans, 2008) and was followed by another initiative to join existing Regional Electricity Markets through the market coupling denominated Price Coupling of Regions (PCR). This initiative was launched by Nordpool, EPEX and MIBEL at the Florence Regulatory Forum in 2009 (Europex, 2009) followed by APX-Endex, Belpex and GME reaching 2860 TWh/year of potential electricity trading (Europex, 2011). Market coupling was firstly achieved between Iberia, Central West Europe and Nordpool in May 2014, one of the main objectives of the PCR initiative. Italy, Austria and Slovenia were then coupled on the 24th February 2015, making up 19 countries now linked, aiming to foster European IEM integration.

Our goal in this study is to detect the effect of the PCR implementation for the market coupling between Nordpool, CWE and MIBEL through the scrutiny of spot price differences. We analyse the market splitting occurrence both before and after the introduction of the PCR.

In the following Section 2 a data overview is presented for the considered electricity markets, followed by the analysis and discussion in Section 3. Section 4 concludes with some remarks for further evaluation.

2 DATA

We extracted hourly price data from Datastream for all the considered electricity spot markets from 1st of January 2013 until 20th of October 2015, except weekends.

Electricity prices are shown in Figure 1 and exhibit the well know characteristics of volatility and mean reversion (Higgs & Worthington, 2008). Moreover, a vertical line is drawn on May 2014 when the market coupling is implemented under the PCR initiative.

Summary statistics for the time series are presented in Table 1. All price time-series have non-normal distribution as confirmed by the Jarque-Bera statistic rejection of the null for normal distribution testing.

Table 1 - Price series summary statistics

	Price APX [€/MWh]	Price BPX [€/MWh]	Price EEX [€/MWh]	Price OMIE PT [€/MWh]	Price OMIE ES [€/MWh]	Price PWNX [€/MWh]	Price DK1 [€/MWh]	Price DK2 [€/MWh]
Mean	46.53	47.75	37.64	47.24034	47.67637	42.41	33.48	34.47
Median	45.85	47.10	35.97	49.57	50	42.11	32.22	33.34
Maximum	130.27	448.70	130.27	123.99	144.48	180.00	2000.00	130.27
Minimum	0.12	0.01	-62.03	0	0	-1.86	-62.03	-62.03
Std. Dev.	12.72	18.80	13.79	17.23097	17.21934	15.71	34.74	13.01
Skewness	0.51	5.98	0.38	-0.61926	-0.59236	0.48	47.26	0.32
Kurtosis	4.07	102.16	5.04	3.758517	3.908398	4.76	2599.13	5.06
Jarque-Bera	1.60E+03	7.29E+06	3.49E+03	1.07E+10	2.93E+05	2.92E+03	4.93E+09	3.39E+03
Probability	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Observations	17542.00	17542.00	17542.00	17542.00	17542.00	17542.00	17542.00	17542.00

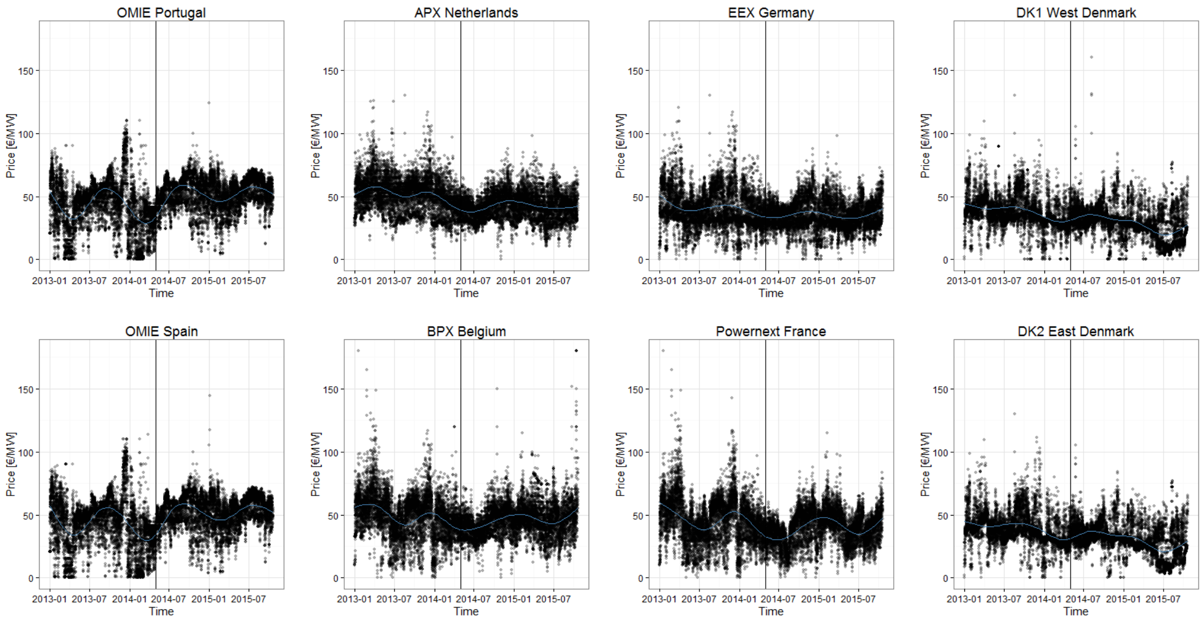

Figure 1 – Price series plots from 1st January 2013 to 20th October 2015

3 ANALYSIS AND DISCUSSION

In Figure 2 the price differences across each electricity market cross-border are plotted. A price difference between adjacent electricity markets consists on a market splitting event. The Market Splitting Hours Share, hereafter the MSplit index, is then calculated considering the share of market splitting hours in a rolling month. Accordingly, the evolution of market splitting behaviour can be plotted and empirically analysed (Figure 3).

After May 2014, date of the market coupling mechanism beginning, it is observed that the number of price difference events (or market splitting occurrences) between Portugal and Spain diminished (Figure 2) and the corresponding effect is also detected in the evolution of the MSplit index plotted in Figure 3. This does not mean that the PCR initiative has caused this improvement, given that a market splitting mechanism was already in place between Portugal and Spain. Moreover, it is expected that market integration improvements like the one observed might be attributed to increasing cross-border interconnection capacity.

One development that can be definitely attributed to the PCR initiative is the one observed between France and Spain. After May 2014, it is possible to witness hour periods of equal price between both electricity markets (Figure 2). This can also be observed by the decreasing MSplit index, nevertheless still with high values demonstrating that improvements in cross-border interconnection capacities are required (Figure 3). The new cross-border interconnection INELFE (INELFE, 2015) started commissioning in February 2015 and because is in commercial operation only since 5th October 2015 (Red Eléctrica de España, 2015), data are scarce and its effect becomes premature to detect in the current study.

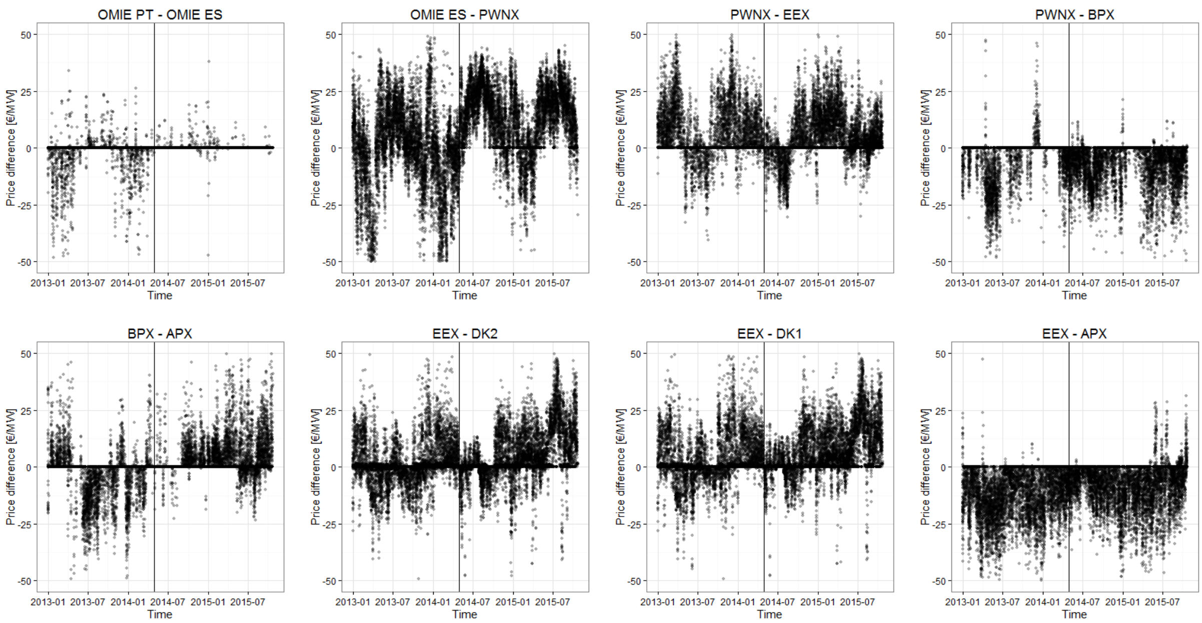

Figure 2 – Price difference series plots from 1st January 2013 to 20th October 2015

In the remaining electricity market interfaces, there is no improvement perceived in the MSplit index plots. All these electricity markets were already linked through some type of market coupling mechanism and as perceived in the MSplit plots, there is some degree of market integration. It should be highlighted that when market splitting occurs between the Netherlands and Germany, the Dutch electricity price is almost always higher than the German one. This can also be seen between France and Belgium, where the French electricity price is most of the times higher in the event of market splitting. A plausible explanation relates to the existence of extensive amounts of renewable source electricity generation in Germany and a high level of nuclear electricity generation in France.

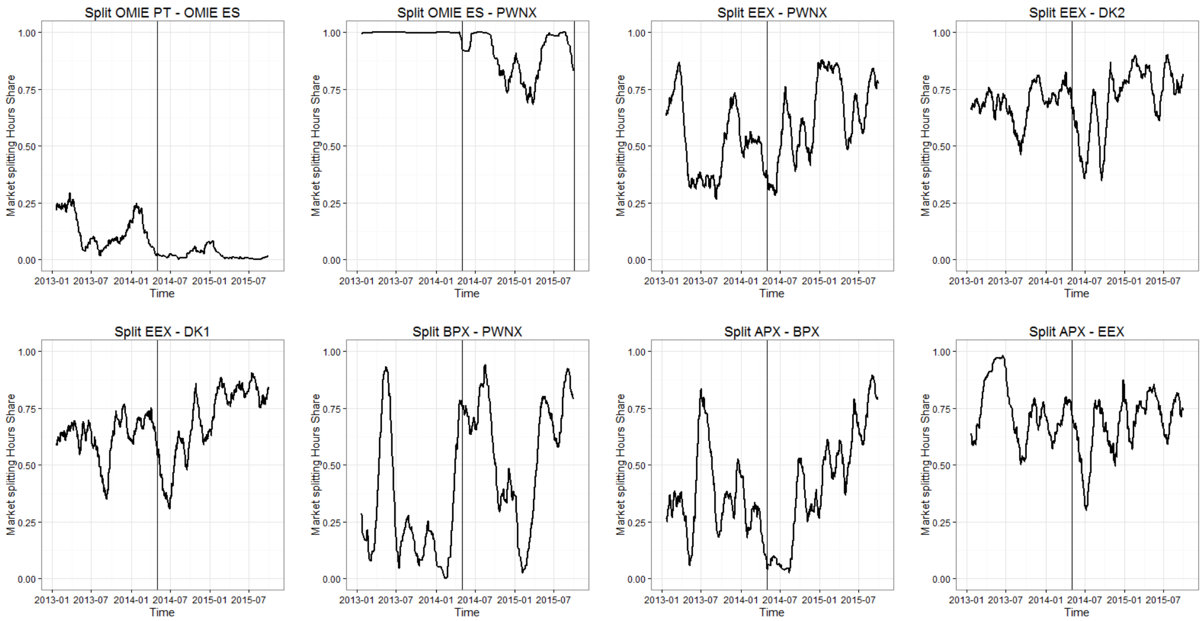

Figure 3 – Market Splitting Hours Share from 1st January 2013 to 20th October 2015

4 CONCLUSION

In this study an empirical analysis is made concerning the introduction of the PCR initiative in the Western European electricity markets, through the observation of the price differences and market splitting evolution. The market coupling mechanism introduction between the Nordpool, CWE and MIBEL is subsequently assessed before and after May 2014, when the market coupling mechanism started.

The PCR launching between Spain and France was successful; however, still requiring additional cross-border interconnection capacity. In future studies the impact of the new cross-border interconnection INELFE should be evaluated. No significant impacts were seen between Nordpool and CWE; the Market Splitting Hours Share level observed before and after the PCR initiative introduction did not present an apparent change. Given the Iberian experience, we are led to believe that the increase in cross-border interconnections would benefit and improve the level of electricity market integration within the CWE and with the Nord Pool, decreasing the Market Splitting Hours Share level.

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Analysis of the determinants of the Brazilian energy mix

Ana Thereza Carvalho Costa[1], Nivalde José de Castro[2], Andre Luis da Silva Leite[3], Ana Luiza Souza Mendes[4]

[1]*UFRJ/FIRJAN, Av. Graça Aranha, 1, Rio de Janeiro, Brazil, ana.costa@pped.ie.ufrj.br*
[2] *GESEL/UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, nivalde@ufrj.br*
[3] *UFSC, Campus Reitor João David Ferreira Lima, Florianopolis, Brazil, andre.leite@ufsc.br*
[4] *GESEL /UFRJ, Av. Pasteur, 250, Rio de Janeiro, Brazil, ana.luiza@gesel.ie.ufrj.br*

ABSTRACT

In 2004 came into force a new model for the Brazilian Electricity Sector (BES). This model was established based on three pillars: expansion of the installed capacity, reasonable tariffs and universalization of the access to electricity. The main change that took place was the resumption of the energy planning for the State's responsibility, which had been transferred to private players in the previous liberal period. This resumption takes place through the creation of the *Empresa de Pesquisa Energética* (EPE), whose purpose is the development of studies and researches to support the planning of the energy sector, guiding the government and industry players in their decision making process and guidelines establishment. Among the major studies carried out by EPE is the *Plano Decenal de Expansão de Energia* (PDE), that annually formulates forecasts for the expansion of the supply and demand of energy for a period of 10 years ahead, therefore becoming an important planning tool for the BES. Thus, the PDE indicates the future electricity mix for the sector. However, EPE's planning is only indicative, making it essential to analyze whether their propositions occur in reality. Therefore, the procurement of installed capacity to be added to the BES and the sources that will compose this future mix need to be investigated. Moreover, with the new model, the procurement of new installed capacity starts to occur through energy auctions. In these auctions, the concession of new plants occurs and it is guaranteed the future supply to attend the demand anticipated by the distribution companies for the regulated consumers. The electricity auctions aim to contract energy with reasonable tariffs. In order for that to happen, the criterion used to define the winner is the lowest rate offered. Thus it is through the electricity auctions that the government coordinates the expansion of the generating capacity and the winner sources will compose the future electricity mix. The composition derived from the results of the auctions often differs from the projections of the PDE, making this differentiation the central object of analysis in this article. In that way, the question that arises is what are the causes that explain the differences between the results of these energy auctions and what it was projected and estimated by EPE in its ten-year planning. The article seeks to make a comparison of PDE's projections since its first formulation in 2006, with the results of the new energy auctions held so far. Essentially, it seeks to answer if, through the indicative planning and the auctions, we are in fact moving towards a strategic electricity mix for the BES.

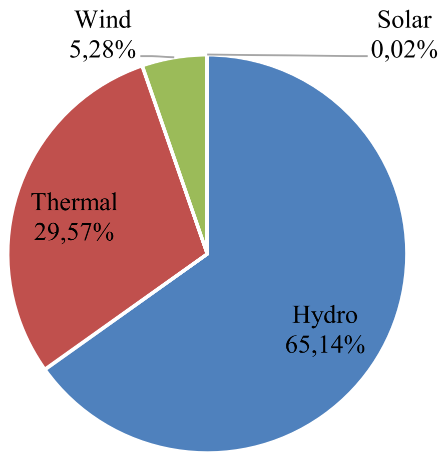
KEYWORDS: Brazilian electricity market; energy planning; electricity auctions

1. INTRODUCTION

Electricity is an essential commodity for all socio-economic sectors, and its uninterrupted supply, with reliability and affordable tariffs, is crucial for the national development. It is also not directly storable in large amounts, implying the need for its generation and consumption to happen simultaneously in order to have an instant balance (Pinto *et al.,* 2007). Investments in the energy sector are also capital-intensive with long-term maturity (Siffert et al., 2009). The combination of these features brings to the sector the need for medium and long-term planning, becoming a fundamental and strategic activity for the Brazilian Electricity Sector (BES), and requiring a deep understanding of its operation, mechanisms and possible adjustments to ensure the balance between supply and demand.

It should be noted that the BES is extremely complex, being fully interconnected[1] through transmission lines with continental proportions. The sector's uniqueness is also complemented by the composition of its energy mix, as can be seen in Graphic 1. In the new model of the BES, the procurement of new plants to compose this electricity mix began to occur through electricity auctions and the sector’s planning is resumed.

Graphic 1 – Brazilian electric mix (2015)



Source: *Agência Nacional de Energia Elétrica* (ANEEL).

Therefore, this paper seeks to make a comparison of the planning proposed by its main instrument, the *Plano Decenal de Expansão de Energia* (PDE), since its first formulation, with the results of the energy auctions held so far, analyzing the energy sources where the greatest discrepancies between what was planned and what was procured occurred. Essentially, it seeks to answer if through the current planning and auction mechanisms, we are in fact moving towards a strategic energy mix for the BES[2].

Accordingly, the first section brings a brief description of the recent history of the BES, followed by the section that characterizes its new model, established between 2003 and 2004. The third section debates one of the major changes that have occurred in this new model: the procurement of electricity through auctions. In the fourth section, it is discussed the resumption of the sector’s planning after the energy shortage crisis that occurred in the country in the biennium 2001-2002, succeeded by an analysis of the comparative results between the planning and the actual result of the auctions. Finally, there is a brief conclusion about the elaborated analysis.

2. BRIEF HISTORY OF THE BRAZILIAN ELECTRICITY SECTOR

[1] Except for the states of Roraima and Amazonas.

[2] It should be noted that this paper is part of a research that the author is developing for her master’s degree.

Throughout the twentieth and twenty-first century, the responsibility for planning the BES changed hands a few times. The regulatory framework has undergone several transformations in that period, especially regarding the participation of the State, alternating moments of predominant participation of public and private capital, be it domestic or foreign (Dias Leite, 2014).

When it comes to the more recent stages of the BES, in the mid-1990s was implemented a liberal reform with the privatization of companies in the sector, beginning in the year 1995. The liberal model also brought up the definitive unbundling of the production chain of the companies in the sector by separating the segments of generation, transmission, distribution and commercialization of electricity. The competition in generation and commercialization segments was encouraged, keeping regulated the distribution and transmission because they are considered natural monopolies in the industry.

Therefore, it can be noted that the BES has moved from a State monopoly system to a market oriented type. As a result, until February 2000, about 65% of the national distribution market had already been transferred to the private sector, with significant participation of international groups, especially from Europe and the United States (Pires, 2000).

However, with the implementation of this new liberal model for the electricity sector, the formulation of energy policies and medium and long-term planning were neglected, since there was no entity responsible for such activity and the regulatory system was not fully mature. During this period the sector planning was set aside and transferred to the responsibility of private agents (Castro *et al*., 2012).

The lack of planning coupled with technical and environmental issues culminated in 2001 in a serious energy supply crisis that generated many discussions about BES's direction. Such crisis resulted in the need for rationing of 20% of the electricity consumption, thus exposing the current model's weaknesses.

As follows, since that model did not appear sustainable, in 2001 the Committee of Revitalization of the Electricity Sector Model is created, with the primary function to draw up proposals to fix current dysfunctions and improve the sector model. Its work resulted in a set of recommendations for amendments in the BES.

In conclusion, the liberal reform implemented in the BES between 1995 and 2002 was ineffective in securing the main objectives of a public service, such as supply reliability, low tariffs and universality (Tolmasquim, 2011). One of the points that explained their inefficiency was the lack of planning. As a result, it begins the implementation of a new model for the BES. The new model brings a resumption of the coordination and planning with a more active role of the State (Tolmasquim, 2011).

3. THE NEW MODEL OF THE BRAZILIAN ELECTRICITY SECTOR

The new model, implemented between the years 2003 and 2004, modified the electric power procurement method and resumed the centralized planning in the sector. In contrast to the earlier time of a more liberal model, this new one is characterized by being hybrid, marked by greater State participation through public private partnerships, with the State in a position of complementarity and orientation in regards to private companies.

The new model was built upon three fundamental objectives: expansion of the installed capacity to meet demand growth, reasonable tariffs and universal access to electricity (Castro *et al*, 2012). In order to meet these objectives, one of the introduced changes was the creation of two energy procurement environments: the Free Market (FM), where it is possible to have a greater negotiation of the supply contracts; and the Regulated Market (RM), in which the procurement of electricity occurs through energy auctions, observing the criterion of the lowest price. The energy procurement in the RM is formalized through regulated bilateral contracts between selling agents and distributors who participate in these auctions.

3.1. The electricity procurement auctions

The energy auctions are an essential tool for the expansion and sustainability of the BES, since it is through them that occurs the procurement of electricity to meet the future demand from distributors and it is granted the concession of new plants. The distributors must guarantee through the auctions the energy to meet the total consumption of its market in the RM. Thus, the amount of energy to be contracted is defined based on the projections of future demand of such distributors in their respective concession areas.

In addition, the electricity auctions seek to procure energy to ensure reasonable tariffs. This objective should be met since the auction winners are based on those suppliers that offer electricity at the lowest price per megawatt-hour (MWh), as the criterion used is the lowest rate. By setting the price of the supply contracts and the participation of energy sources used to generate energy, the auctions also influence the tariffs paid by the final consumers and the quality of the energy mix.

Accordingly, a greater understanding of its functioning and impacts is indispensable to coordinate a sustainable electricity sector. Furthermore, it is important to note that the resulting contracts from auctions are long term and may last between 15 and 30 years when it comes to new plants. Thus, it is clear that decisions taken within that framework will influence the sector for a significant period of time. For that reason, all influencing factors must be studied carefully.

Energy auctions take place on an annual basis and are subdivided into two main categories: the existing energy auctions and new energy auctions. Reserve energy auctions may also occur. The new energy auctions can be for the beginning of supply in three years (A-3), which, given the short time frame for implementation, thermoelectric plants tend to be more competitive, or five years (A-5), in which hydropower plants, a cheaper energy source[3] but with a higher implementation time, are supposed to be more competitive. Wind power has proved effective in auctions with both time frames. The new energy auctions can also be of a structural type, designed to procure energy from generation projects that have some type of priority in its implementation[4] or alternative sources, to promote the procurement of energy form wind power projects, biomass or small hydroelectric plants.

Existing energy auctions, on the other hand, are performed each year in order to contract energy derived from plants already built and for delivery of energy in the year following its realization, as contracts in force expire. These auctions also allow an adjustment of the contracts since conditions may change according to variations in the consumption of energy and costs, ensuring a greater contractual flexibility so that distributors can handle market risks. There are three types of existing energy auctions: in addition to alternative sources, there are also adjustment auctions, aimed at adapting the contracting of electricity by distributors, and A-1 auctions, for energy delivery one year after the purchase.

Finally, there are the reserve energy auctions, in which new plants that provide the BES a generation reserve capacity are procured. Reserve auctions were designed to mitigate the hydrological risk and incorporate bioelectricity in the Brazilian energy mix, increasing the safety of the system (Castro, 2008). This process takes place so that there is an increase in the security of supply of electricity. Figure 1 summarizes the types of auction.

[3] When compared to thermal plants in Brazil.

[4] Traditionally, large hydroelectric plants.

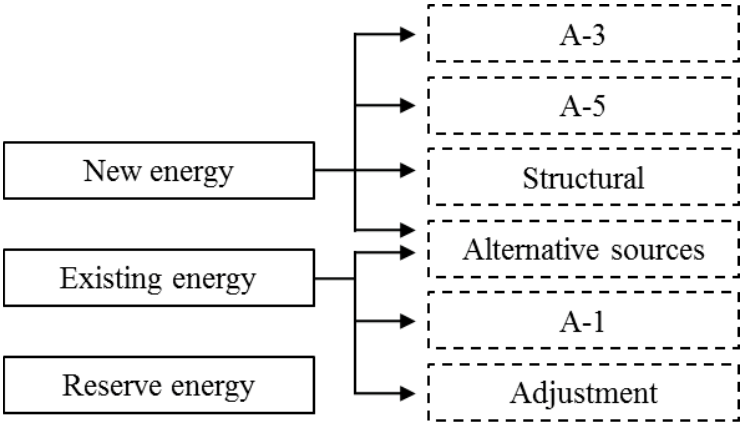


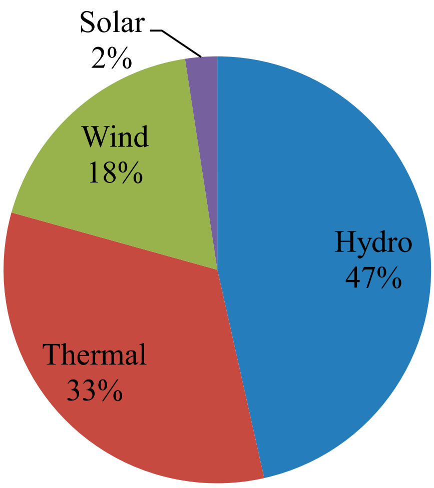
Figure 1 – Types of auctions for the procurement of energy in the Brazilian Electricity Sector.

Source: Prepared by the authors with data from the Ministry of Mines and Energy (MME).

Hence, it is evident that the new energy auctions are largely responsible for the expansion of the national installed capacity, since they promote the purchase of energy from new generation projects, implemented and operated by the auction winners. However, as the new energy auctions, the reserve auction also add new installed capacity to the BES.

Graphic 2 shows the share of each source in the total procurement of energy occurred through auctions[5], since the first one held in 2005. It is noted that the most procured source was hydroelectricity, followed by thermal plants. Wind farms were also great winners in the auctions, especially in recent years. The solar source, in turn, still has a very low insertion in the Brazilian energy mix.

Graphic 2 – Energy procurement in auctions that have added new installed capacity to the BES (2005-2015)



Source: Prepared by the authors with data from the *Empresa de Pesquisa Energética* (EPE) and *Câmara de Comercialização de Energia Elétrica* (CCEE).

[5] Only auctions that have added new installed capacity to the BES were considered.

It is noteworthy that, since the longer time frame for the beginning of supply of energy procured at an auction is five years and the lowest is three years, the national energy mix is now fully procured by the year 2018. Among the years 2018 and 2020, is partially procured, once the execution of an A-3 auction in the future may also lead to changes between these years.

Concluding, the success of the auctions is key to the balance between supply and power consumption and hence to reduce the deficit and rationing risks. It is through the new energy auctions that the government coordinates the expansion of generating capacity and are their winning sources that will make up the future electricity mix. For this reason, such auctions end up being one of the main instruments of planning in the BES. Therefore, an analysis of their effectiveness as such is relevant. Thus, in addition to projects already contracted via auctions, it is necessary to analyze what is contained in the planning of the BES.

3.2. The resumption of planning in the new model of the Brazilian Electricity Sector

Besides the change of the form of power procurement, another modification of utmost importance brought by the new BES's model was the return of centralized planning for the sector. That decision followed an arduous moment experienced by the country: the shortage crisis and the consequent rationing of electricity occurred in the 2001-2002 period. This situation demonstrated the indispensability of planning to ensure energy security in the country without compromising three central aspects: economic, social and environmental.

Thus, in 2004 it was authorized the creation of the *Empresa de Pesquisa Energética* (EPE), in order to conduct studies and researches to subsidize the energy sector planning, guiding the government and other agents in their decision making and establishing guidelines. The studies carried out by EPE cover various horizons, making projections of economic and energy scenarios to ensure the future supply in a safe and economically viable path for the whole society.

Among these studies, the PDE must be highlighted. PDE is elaborated on an annual basis and makes forecasts for the expansion of supply and demand for a period of 10 years ahead. For this purpose, scenarios of sustainable energy supply are elaborated through the analysis of macro-economic, environmental, social and technological variables. Such projections are essential for a sector where investments are capital intensive and have long-term maturity as aforesaid, that is, its guidelines must be established with responsibility and in advance. Accordingly, PDE is an important tool for planning the BES.

On the other hand, although the PDE indicates the future energy mix for the sector, its results are only indicative[6]. Indeed, despite EPE's recommendations, the winning bidders in the auctions are the sources that will make up the future mix. Thus, it is essential to evaluate whether EPE's propositions occur in reality or not, through a study of the mechanisms that put it into practice. In this scope, it is relevant to elaborate a comparative analysis between the projections of the PDE and the result of the electricity auctions which procured new capacity for the BES, since its first formulation.

4. COMPARATIVE RESULTS BETWEEN THE AUCTIONS AND THE PLANNING PROJECTIONS

As previously mentioned, the PDE considers a ten-year horizon for the composition of the future electric mix in the BES. Aiming for greater clarity in comparing the data from the studies and the results from the auctions, the sources analyzed were unified in four major groups: hydro, thermal, wind and solar. It is worth mentioning that solar just started being considered by the PDE (it first appeared in the 2014-2023 edition), thus, lacking values for the other periods.

The collected data refers to the evolution of the installed capacity by power source, in each of the seven plans analyzed[7]. Once these data was selected, it was attempted to find the increase planned by source for each of the

[6] Except for large hydropower plants.

[7] There are no data for the 2009-2018 period because PDE was not elaborated by EPE for that horizon.

years, as seen in Table 1. For example, the line for the PDE 2010-2019 for the hydroelectric source shows the increases projected by the plan that encompasses such ten-year horizon, for each of the years under consideration. That is, according to this plan, in 2011, 2,387 MW from hydroelectric plants would be entering the national energy mix.

The first factor that stands out with the analysis of Table 1 relates to the wide variation found between the plans. As an example, it can be investigated the planning of wind source for the year 2015; while the PDE 2007-2016 did not project any increase, the study for the years 2014-2023 planned an increase of 3,567 MW for that year. Such variations can also be found in other sources and for other periods.

On the one hand, it is understood that it is natural to have some differentiation between studies, possibly due to economic and environmental issues. However, so that the BES can benefit from an integrated long-term vision, it is essential to the planning to have a more uniform central direction. Moreover, it is important to compare the planned values of such increases to the BES with the actual results of the auctions. Evidently, the development of a planning with a ten-year horizon is not trivial. Therefore, it is expected that the forecasts for the coming years to be more realistic than those prepared with a higher timeslot. In this sense, the values highlighted in bold and underlined in Table 1 refer to the ones that were last planned to each year that was considered. For example, for the thermal source in 2013, the last projected value was an increase of 2,885 MW, that is, that amount should be close to the one that was actually procured through the auctions. Thus, Table 1 reflects this comparison. The "Auction" line refers to the amount that was actually procured for the beginning of supply to the energy mix in the year highlighted.

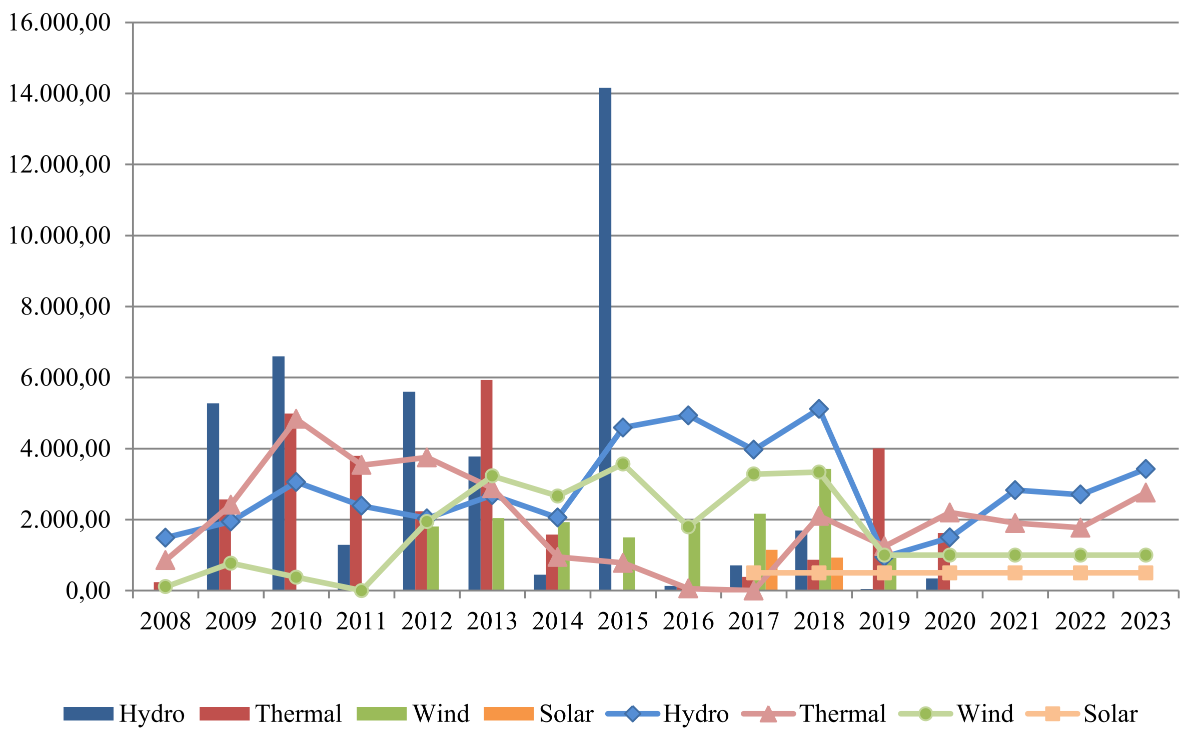
Table 1 – Increase to the installed capacity planned by the PDE *vs*. procurement in the auctions by source (MW).

	PDE	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro	2007-2016	**1.489**	912	2.661	2.047	2.059	4.982	7.046	6.963	4.608							
	2008-2017		**1.944**	**3.058**	1.887	688	2.875	2.861	5.397	7.342	6.536						
	2010-2019				**2.387**	812	2.604	1.732	5.475	6.070	3.925	4.797	8.651				
	2011-2020					**2.034**	2.371	1.147	4.521	5.123	5.739	5.277	2.522	3.899			
	2012-2021						**2.690**	1.605	4.436	4.730	4.998	4.037	2.421	3.387	5.463		
	2013-2022							**2.053**	4.182	3.665	3.921	5.048	1.785	2.855	2.815	5.568	
	2014-2023								**4.590**	**4.934**	**3.966**	**5.118**	**947**	**1.494**	**2.832**	**2.705**	**3.428**
	Auction	0	5.275	6.599	1.293	5.601	3.782	450	14.162	135	710	1.692	44	346			
Thermal	2007-2016	**855**	1.283	1.542	3.099	2.971	1.530	1.550	200	500							
	2008-2017		**2.418**	**4.833**	2.694	776	5.216	1.350	900	0	0						
	2010-2019				**3.534**	1.684	5.092	399	1.755	200	150	350	400				
	2011-2020					**3.750**	5.152	372	300	1.705	350	330	370	460			
	2012-2021						**2.885**	4.296	50	1.455	100	750	950	900	1.850		
	2013-2022							**949**	93	0	100	2.652	1.060	1.210	1.380	700	
	2014-2023								**780**	**60**	**0**	**2.103**	**1.250**	**2.200**	**1.900**	**1.770**	**2.760**
	Auction	238	2.569	4.985	3.794	2.236	5.929	1.584	0	100	389	873	4.010	1.627			
Wind	2007-2016	**112**	0	0	0	0	0	0	0	0							
	2008-2017		**771**	**378**	0	0	0	0	0	0	0						
	2010-2019				**0**	1.805	400	400	400	400	400	400	400				
	2011-2020					**1.941**	2.048	900	850	760	900	850	1.000	1.000			
	2012-2021						**3.227**	1.943	949	1.283	500	1.150	1.650	1.430	1.450		
	2013-2022							**2.663**	2.536	1.683	1.283	1.000	1.000	1.000	1.200	1.200	
	2014-2023								**3.567**	**1.797**	**3.283**	**3.340**	**1.000**	**1.000**	**1.000**	**1.000**	**1.000**
	Auction	0	0	0	1.806	2.048	1.929	1.505	1.934	2.171	3.425	926	0	0			
Solar	2007-2016																
	2008-2017																
	2010-2019																
	2011-2020																
	2012-2021																
	2013-2022																
	2014-2023							**0**	**0**	**0**	**500**	**500**	**500**	**500**	**500**	**500**	**500**
	Auction	0	0	0	0	0	0	0	0	1.154	929	0	0	0			

Source: Prepared by the authors with data from EPE and CCEE.

In order to emphasize this comparison, Graphic 3 shows the data for the line highlighted in bold and underlined in Table 1 with the energy that was effectively procured in the auctions. As for the thermal source, the increase planned and the one procured are sometimes equivalent, but when it comes to hydro, such fact does not occur. In general, the data indicates a mismatch between the planning and its main tool: the procurement through auctions.

Graphic 3 – Last increase to the installed capacity planned for each year by the PDE *vs*. procurement in the auctions.



Source: Prepared by the authors with data from EPE and CCEE.

The aforementioned mismatch can be seen clearly in Graphic 3. As an example, the latest data available from the planning in the year 2009 on the PDE 2008-2017 foresaw an increase in the installed capacity from hydroelectric power of 1,944 MW. However, the energy procured by the auctions to begin supply in that year accounts for 5,275 MW, more than 2.7 times what was expected. Similarly, for the year 2015, the latest forecast was 4,590 MW to be added to the mix. Because of the procurement of energy from Belo Monte (11,233 MW) in a specific structural auction for that plant, the value was 209% higher, resulting in the procurement of 14,162 MW, with the supply beginning in 2015. Other similar occurrences can be noticed in Graphic 3.

Analyzing the dispersion between the planned and the procured in the auctions through the Mean Squared Error (MSE)[8], it is clear that the hydro source presented the greatest difference between both[9]. Excluding Belo Monte from the analysis, the MSE has fallen almost by half, however, it was still six times higher than that presented by thermal. In turn, wind power had an MSE 44.26% lower than that reported by thermal, while solar presented the lowest MSE, but it is worth noting that solar energy is only present in the sample from 2017 on.

[8] The MSE analysis allows a comparison of which source presented the greatest difference between what was planned by the PDE and what was procured at the auctions.

[9] Since for the years 2018 onwards it is still possible that new auctions that result in the procurement of new installed capacity occur and alter the data analyzed, it was considered to the MSE analysis only the period from 2008 to 2018.

Finally, it should be noted that from the year 2020 on, energy has not yet been procured, since, as mentioned above, the auction with the longer term is that of type A-5 for power supply five years after its execution. However, due to the ten-year planning of the sector, the forecasted data can already be observed, as seen in Graphic 3. Therefore, it is essential to continue this study in the future in order to analyze if the noted mismatch remains. Concluding, the indicative planning of the sector is not being observed in reality; auctions have obtained significantly different results when compared to the PDE.

5. CONCLUSION

First, it is important to note that a sector with as many specifics as the electricity sector requires significant caution in regard to its long-term sustainability. As mentioned, due to the unique characteristics of electricity, a well-structured planning is essential, and the BES has suffered from its absence. In this sense, this paper aimed to make an analysis of such planning and its effectiveness through the electricity procurement mechanism via auctions.

Among the main changes brought by the new model of the BES, certainly the resumption of planning stands out. Through the creation of EPE and its plans, such as the PDE, Brazil regained its long-term vision when it comes to the energy mix composition. However, what is observed in reality is an inconstancy of the elaborated projections, with many modifications in relation to their various annual editions. Although it is understandable that there can be differences between the studies, planning generally requires a better defined guideline.

Regarding the practical implementation of these plans, it was demonstrated that there is a mismatch between the two factors. Since the new energy auctions are usually generic and rarely have any directions concerning with are the energy sources that must be procured and its winners are defined by the criterion of the lowest price, what has ultimately been happening is that the definition of our future energy mix is being based only on the reasonable tariffs goal.

On the one hand, it is understood that price reductions to final consumers is essential to the competitiveness of the economy. However, it is essential that the sector moves towards a strategic energy mix, with diversified sources to mitigate risks and take full advantage of national potentials. The criterion of the lowest rate does not seem sufficient to achieve this goal; reasonable tariffs alone is not adequate to ensure the expansion of the system safely.

In conclusion, there is a lack of synergy between the main pillars of the BES. Auctions should have a better signaling as to which energy sources it will procure, and such information should be consistent with a well-structured sectorial planning. Moreover, future studies that seek to analyze in greater depth the economic pricing methodology of auctions in order to specify the necessary changes in it, can be of great relevance. Only with the use of accurate and appropriate mechanisms that we will, in fact, move towards a greater unity between planning and auctions: a strategic mix for the BES.

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Renewables versus Efficiency:A Comparison for Spain

Juan-Manuel Roldan-Fernandez[1], Manuel Burgos-Payan[2], Jesus-Manuel Riquelme-Santos[3] and Angel-Luis Trigo-Garcia[4]

Departamento de Ingeniería Eléctrica, Universidad de Sevilla,
Camino de los Descubrimientos, s/n. 41092, Sevilla. Spain
[1] jmroldan@us.es; [2] mburgos@us.es; [3] jsantos@us.es; [4] trigoal@us.es

ABSTRACT

Along the last decades, renewable energy (especially wind) in Spain has undergone a significant development (lead by a small group of renewable promoters supported by institutional policies), contributing significantly to electric generation mix (42.8% renewable in 2014). On the contrary, the promotion of energy efficiency actions (accomplished by a large number of industrial and domestic consumers that are very poorly supported by energy policies), are still little explored. According to ODYSSEE-MURE (2015), energy efficiency at the EU-28 level improved by 1.2%/year on average from 2000 to 2013, while for the case of Spain, the rate of improvement was only 0.6 %/year on average throughout that period (the lowest rate of energy efficiency improvement in the EU-28).

This work seeks to compare the integration of renewable production with energy efficiency plans, in order to advance their potential economic impact in the wholesale market and consumers. To reach that goal, the hourly market data retrieved from the Spanish/Iberian Market Operator (OMIE) for 2014 will be used as a base. Then, a set of pseudo-heuristic scenarios with integration of renewable production and energy efficiency (load saving) will be elaborated and analyzed to quantify what are expected to be the main effects on the Spanish electricity market and consumers.

The results will show that energy efficiency exhibits the best performance in terms of economic efficiency (less cost of the traded energy) and environmental sustainability (greater replacement of fossil fuels).

KEYWORDS: Electricity markets, Renewable energy, Energy efficiency, Merit-order effect

INTRODUCTION

Over recent years there has been a significant effort in the electrical systems of the EU countries and many others worldwide, to fulfill the mandatory commitments derived from the Kyoto Protocol and its successors (EC, 2009). Thereby, the generation fleet has diversified significantly in terms of technology generation, mainly due to large-scale integration of production based on renewable energy. Consequently, electrical systems are evolving towards a generation fleet that is much more diverse, dispersed and decentralized, with a much larger number of generators, in which the renewable generation has a significant and growing share.

The reduction of the demand via the promotion of load saving programs or the enactment energy efficiency policies could also be another less explored tool to accomplish the commitments from the Kyoto Protocol. In fact, there exist a certain synergy between energy efficiency and renewables since when the demand decreases, a fixed amount of renewable production gives place to a greater share of renewables on the generation mix. In any case, most counties have chosen the development of renewables as a means to fulfill its environmental commitments.

This is the case of Spain where along the last decades, renewable energy (especially wind) has undergone a significant development. This growth has been led by a relatively small group of renewable promoters supported by institutional policies, and have made renewables to be a significant contributor to electric generation mix (42.8% renewable, 20.4% wind in 2014). On the contrary, the promotion of energy efficiency actions, accomplished by a large number of industrial and domestic consumers that are very poorly supported by energy policies, still are little explored. According to ODYSSEE-MURE (2015), energy efficiency at the EU-28 level improved by 1.2%/year on average from 2000 to 2013 (about 15% over the period). However, the pace of progress has slowed down since the economic crisis: the annual gain between 2000 and 2007 has dropped from 1.3%/year to 1%/year between 2007 and 2013. For the case of Spain, energy efficiency only improved on average by 0.6 %/year throughout that period, which is the lowest rate of energy efficiency improvement in the EU-28. Moreover, energy conservation policies seem especially well suited for Spain due to its high level of energy dependence. According to Eurostat (Eurostat, 2014) the Spanish rate of gross energy dependency is always much higher than that of the EU average. For 2013, the level of gross dependence of Spain was 70.5% in 2013, well above the 53.2% of the UE average.

This work seeks to compare these two approaches for the Spanish case: the integration of renewable production and the development energy efficiency programs, in order to advance their potential impact on the electricity market. With this purpose, first a qualitative model, based on the linearization of the wholesale market around the clearing point, is used to examine some basic hypotheses. An appropriate set of empirical-based scenarios with renewables and energy efficiency are then generated from the retrieved historical information of the Iberian/Spanish Market Operator (OMIE) for the year 2014, in order to quantify the main effects on the market.

The content of the paper is as follows. After the introduction, the Spanish/Iberian electricity market is briefly described and a qualitative model, based on the linearization of the market, is used to examine some basic hypothesis regarding the expected effects of renewables and energy efficiency. The hourly merit-order generation and demand curves throughout 2014, retrieved from the archive of the Market Operator (OMIE) are then used as source data for the generation of realistic renewables and energy efficiency scenarios. The main potential effects of renewables and energy efficiency on the market are then quantified and analyzed. Finally, the paper closes with the main findings of the comparison.

The Iberian Market of Electricity

OMIE is the Market Operator of the Iberian Electricity Market, which is the European regional market for Spain and Portugal. Although OMIE has been integrated into the European Price Coupling (EPC) since 2014, this does not affect the actual market rules (OMIE, 2014). The market is organized as a sequence of markets: the day-ahead market, the intra-day market, with six sessions a day, which operates close to real time, and the ancillary services market.

The daily market involves the scheduling of electricity transactions for the day ahead, which is performed through the submittal of electricity sale and purchase bids by market agents. The daily market is composed of 24 hourly markets that clear once a day. On the supply side, the Iberian electricity producers submit their bids specifying the price at which they are willing to produce a given amount of output from each of their production units, one day ahead. Similarly, demand agents submit their bids specifying the price at which they are willing to buy a given amount of energy. Once the supply and demand bids have been submitted by their agents, the Market Operator (OMIE) creates a merit-order dispatch, for every hour of the day ahead, by ordering the supply bids in ascending price order and demand bids in descending order. The hourly equilibrium price and the generation dispatch are determined through market clearing, i.e. by computing the intersection between the supply and demand curves. Conditional on being dispatched, the price to be received or paid by the market participants is set according to a uniform-price auction. Irrespective of their bids, the price producers receive, or the price paid by demand units is set equal to the highest accepted supply bid: the so-called system marginal price.

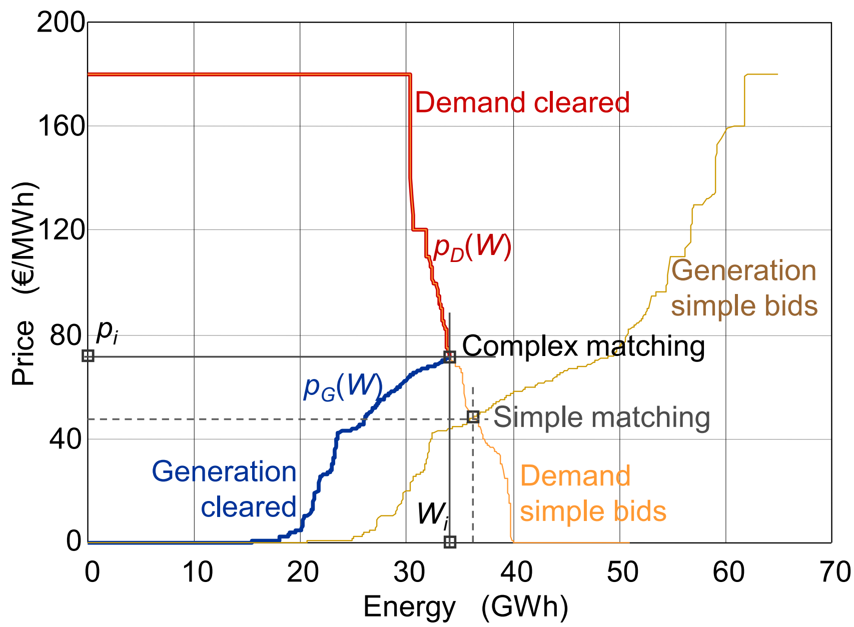

Fig. 1. Merit order generation and demand curves for a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) corresponding to the Iberian market, OMIE. Example of simple (traded energy, W_{is} = 36.81 GWh; clearing price, p_{is} = 49.57 €/MWh) and complex matching rules (traded energy, W_i = 34.18 GWh; clearing price, p_i = 71.00 €/MWh) (OMIE).

Two kinds of bids are considered in the Iberian Electricity Market: simple and complex bids. Simple bids are just simple price and amount of energy bids. Complex bids are bids (for generators only) which include any of the following conditions: indivisibility of blocks of energy, minimum income, programmed stops and load ramps. First, the simple matching procedure of the Market Operator (OMIE) finds a solution for simple bids (Fig. 1). An optimization algorithm (EUPHEMIA, 2013) then finds a new solution which takes complex offer bids into account. Subsequently, the final clearing price and traded energy are set for the considered hour. Finally, the System Operator (REE – Red Eléctrica de España) validates the schedule of the units while considering the electrical system's technical constraints. As often happens in optimization problems, an increase in the number of restrictions leads to a degradation of the optimality of the solution. In the market case, complex offer bids (significantly) increase the final clearing price and (slightly) reduce the traded energy as shown in Fig. 2.

QUALITATIVE ANALYSIS OF THE WHOLESALE MARKET

First, with the intention of advancing and explain some of the trends and results, a simplified analysis is performed. Then, with the methodology that will be exposed later, the validity of the assumptions generated by this preliminary analysis will be investigated.

In Fig. 1 can be seen both the merit-order generation curve, $p_G = p_G(W)$, and the demand curve, $p_D = p_D(W)$, as well as the traded energy ($W_i = 34183.4$ MWh) and the matching clearing price ($p_i = 71.00$ €/MWh) for a peak hour (20:00 h) on a winter workday (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market (OMIE). By its own nature, the supply curve, $p_G = p_G(W)$, has a positive slope, and the demand curve, $p_D = p_D(W)$, has a very negative slope.

If the supply and demand curves were continuous (and not stepped) and $m_G = dp_G(W)/dW > 0$ and $m_D = dp_D(W)/dW << 0$ were, respectively, the slopes of the supply ($m_G = 1.4$ €/GWh) and demand curves ($m_D = -13.5$ €/GWh) at the initial clearing point (A in Fig. 2), then both the supply and demand curves could be linearly approximated, in the surroundings of the initial clearing point (W_i,p_i), as:

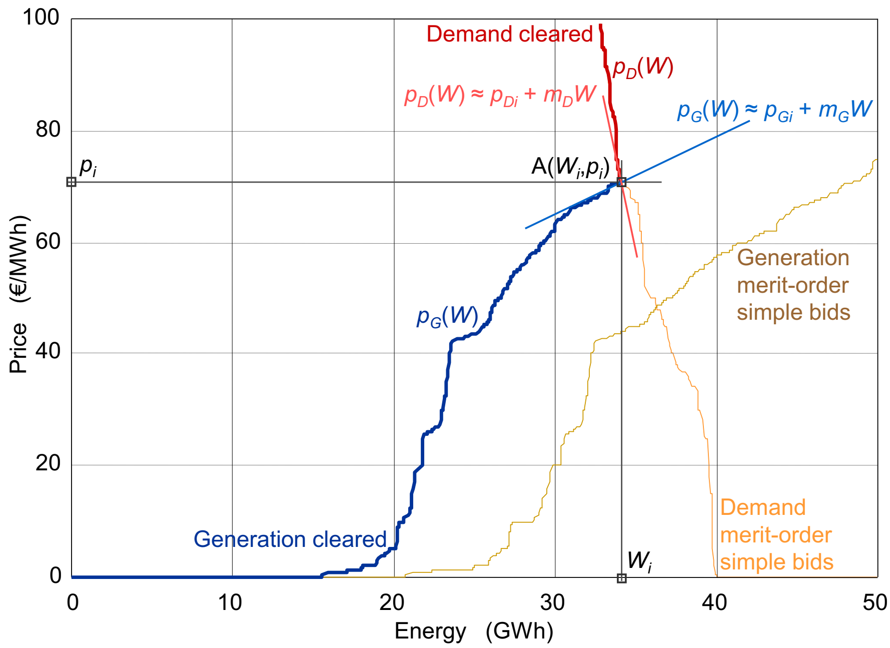

Fig. 2. Merit order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves as well as the traded energy, $W_i = 34.18$ GWh, and the matching clearing price, $p_i = 71.00$ €/MWh, for a peak hour (20:00 h) in a

winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market (OMIE). Linearization of the market around the initial matching point.

$$p_G(W) \simeq p_i + m_G(W - W_i) = p_i - m_G W_i + m_G W = p_{Gi} + m_G W$$

$$p_D(W) \simeq p_i + m_D(W - W_i) = p_i - m_D W_i + m_D W = p_{Di} + m_D W$$

where the respective ordinates at the origin are:

$$p_{Gi} = p_i - m_G W_i$$

$$p_{Di} = p_i - m_D W_i$$

The total initial income for the producers or the total initial cost for consumers, $C(W_i)$, derived from the energy trading in the wholesale market, considering only the market rules, is:

$$C(W_i) = W_i \cdot p_i$$

With this linearized market model around the clearing point, a comparison between the influence of the integration of renewable generation and DSM (energy efficiency) can be evaluated in order to advance of the potential effects of these measurements on the performance of the market. It must be remarked that since the wholesale market is a marginal market, the clearing point is the most important factor to know the impact of these measurements. Although the linear approximations of the merit-order curves ($p_G \approx p_{Gi} + m_G W$ and $p_D \approx p_{Di} + m_D W$) differ from the actual production and demand curves ($p_G = p_G(W)$ and $p_D = p_D(W)$), both sets of curves can lead to the same (or very close) clearing point. This finally determines the price that every buyer has to pay to producers and the amount of energy that generators have to deliver to the customers.

Integration of Renewable Energy

The Iberian market regulation currently requires the Market Operator to include all bids received from renewable generators as long as they cause no technical difficulty for the operation of the system. Therefore, the integration of new renewable generation bids ($\Delta E_R > 0$) at very low (or even null) marginal price yields a mainly right-hand-side shift of the initial merit-order generation curve. The linear approximation of this new supply curve, $p_{GR} = p_{GR}(W)$, is shown in Fig. 4 as a straight line parallel to the primitive generation curve:

$$p_{GR}(W) = p_G(W - \Delta E_R) \simeq p_{Gi} + m_G(W - \Delta E_R) = p_{Gi} - m_G \Delta E_R + m_G W = p_{GRi} + m_G W$$

where the ordinate at the origin is:

$$p_{GRi} = p_{Gi} - m_G \Delta E_R = p_i - m_G(W_i + \Delta E_R)$$

With this linearized market model, the new clearing price and traded energy (B shown in Fig. 3) can be obtained by equating the new generation curve with the demand curve:

$$p_{GR}(W) \simeq p_{GRi} + m_G W = p_D(W) \simeq p_{Di} + m_D W$$

The traded energy, $W = W(\Delta E_R)$, can now be expressed as:

$$W(\Delta E_R) \simeq \frac{p_{Di} - p_{GRi}}{m_G - m_D} = \frac{p_i - m_D W_i - p_i + m_G(W_i + \Delta E_R)}{m_G - m_D} = W_i + \frac{m_G}{m_G - m_D}\Delta E_R = W_i + \Delta W(\Delta E_R)$$

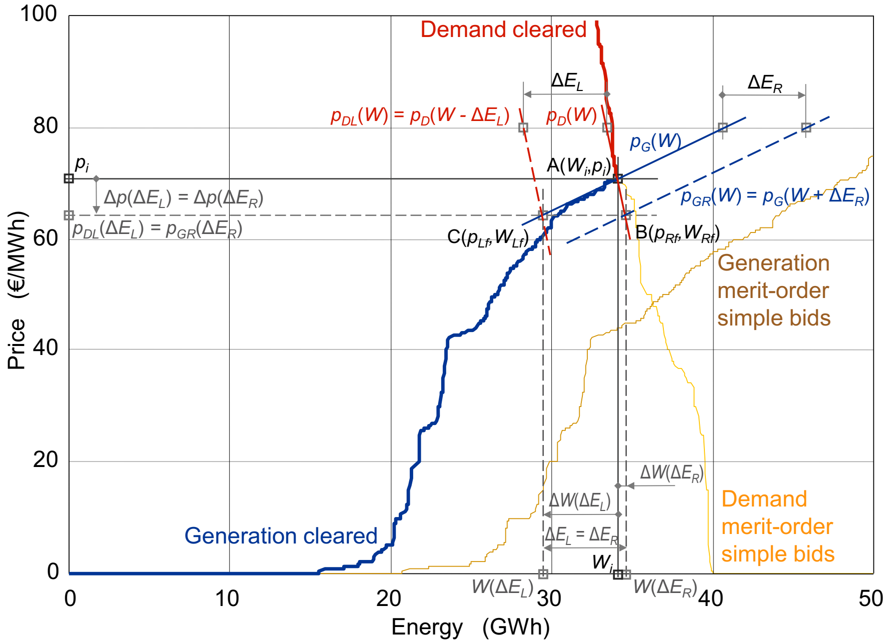

Fig. 3. Merit order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves and matching clearing price (p_i = 71.00 €/MWh) and traded energy (W_i = 34.18 GWh) for a peak hour (20:00 h) in a winter working day (Tuesday, February 10, 2015) corresponding to the wholesale Iberian market [OMIE]. Changes in the market-clearing price and energy traded due to the integration of new renewable generation and due to the reduction of the demand derived from the improvement of energy efficiency.

As a result, the increment of traded energy can be approximated as:

$$\Delta W(\Delta E_R) \simeq \frac{m_G}{m_G - m_D}\Delta E_R > 0$$

The clearing price, $p_{GR}(W) = p_D(W)$, becomes:

$$p_{GR}(W = W_i + \Delta W(\Delta E_R)) \simeq p_{GRi} + m_G(W_i + \Delta W(\Delta E_R)) = p_i + \frac{m_G m_D}{m_G - m_D}\Delta E_R = p_i + \Delta p_R(\Delta E_R)$$

where the price variation (reduction) is

$$\Delta p_R(\Delta E_R) = \frac{m_G m_D}{m_G - m_D}\Delta E_R < 0$$

It should be observed that, since the slope of the supply is smaller than that corresponding to the demand curve, in absolute values ($0 < m_G << |m_D|$), the increment in traded energy is significantly less than the increment in renewable energy bids integrated into the market:

$$0 < \frac{\Delta W(\Delta E_R)}{\Delta E_R} \simeq \frac{m_G}{m_G - m_D} \ll 1$$

This means that the clearing of a certain amount of renewable energy bids, ΔE_R, by the Market Operator, leaves out almost the same amount of energy bids from other more expensive and probably polluting production technologies, $\Delta W(\Delta E_R) << \Delta E_R$, and leads to a reduction of the hourly clearing price proportional to the amount of cleared renewable energy. This is the base of the so-called merit-order effect of renewable energy (Azofra et al., 2014; Burgos et al., 2013; Roldan et al., 2014; Saenz de Miera et al., 2008; Sensfuss et al., 2008).

Energy Efficiency

The consumers that apply load saving or energy efficiency programs can profit from a reduction in the electricity energy bill, mainly due to a reduction of the demanded energy. The curtailment of certain amount of demand bids ($\Delta E_L > 0$) at high marginal price, where the energy efficiency actions would be more cost-efficient, mainly results in a left-shifting of the initial merit order demand curve. The linear approximation of this new demand curve, $p_{DL} = p_{DL}(W)$, is shown in Fig. 3 as a straight line parallel to the primitive demand curve:

$$p_{DL}(W) = p_D(W + \Delta E_L) \simeq p_{Di} + m_D(W + \Delta E_L) = p_{Di} + m_D \Delta E_L + m_D W = p_{DLi} + m_D W$$

where:

$$p_{DLi} = p_{Di} + m_D \Delta E_L = p_i - m_D(W_i - \Delta E_L)$$

The new clearing price and traded energy (C in Fig. 3) can now be obtained by equating the new (reduced) demand curve with the primitive generation curve. It is worth noting that, since the slope of the supply is less inclined than that corresponding to the demand curve, in absolute value ($0 < m_G << |m_D|$), the reduction in traded energy is similar to (but smaller than) that of the saved load bids:

$$0 > \frac{\Delta W(\Delta E_L)}{\Delta E_L} \simeq \frac{m_D}{m_G - m_D} > -1$$

As a result, the reduction of an amount of demand bids resulting from a certain energy efficiency improvement of the load, ΔE_L, causes the Market Operator to leave out almost the same quantity of generation bids from production technologies of a more expensive nature, $W_L(\Delta E_L) \cong \Delta E_L$, and this leads to a reduction of the clearing price and cost of the traded energy proportional to the amount of saved energy bids. This forms the base of what could be called the merit-order effect of the energy efficiency, which is very similar to that corresponding to renewables.

Finally, the following hypotheses are stated:

- The reductions in the clearing price for the renewable and energy efficiency scenarios are the same.
- The energy efficiency scenario leads to a reduction in the traded energy which is almost equal to that of saved energy, while the renewable scenario leads to a slight increment in the traded energy. This means that the energy efficiency is (slightly) more effective than renewables in eliminating (replacing) the more expensive and probably polluting generation technology.
- The reduction of the cost of the traded energy in the energy efficiency scenario is greater than that corresponding to the renewable scenario, since the reduction in the efficiency scenario profits from both the reduction in the clearing price and from the reduction in the amount of traded energy.

METHODOLOGY AND RESULTS

The hourly merit-order generation and demand curves for the year 2014 have been retrieved from the historic data archive of the Iberian Market Operator (OMIE). That means 8760 hourly markets with hundreds of production and demand bids taking part in each hourly market. This vast amount of hourly market bids handled for each scenario made desirable a simplification in the complex clearing rules of the Market Operator in order to simulate new scenarios. As a consequence, a simplified procedure similar to that used by the Market Operator (OMIE) is applied with the intention of performing a quantitative analysis of the scenarios.

For each new scenario analyzed, new hourly merit-order generation and/or demand curves are produced by first locating the bids of the type of agent under interest (i.e. renewables or consumers bids) in the hourly merit-order (generation and/or demand) curves. The bids under interest are then modified (amount of energy and price) by taking into account the appropriate characteristics of the scenario under consideration. The modified bids corresponding to the new scenario are subsequently inserted properly into the retrieved hourly merit-order curves: upward price order for bids in the generation curves, and downward order for the bids in the demand curves. When new market scenarios are developed through the modification of the supply and/or demand curves, it is necessary to consider that the bids of the other agents would remain the same when increasing or reducing new generation or demand bids. Fortunately, this hypothesis of a perfect market can be considered fulfilled since each market agent should elaborate their bids without any knowledge of the bids of the other agents. Finally, the matching point corresponding to the new scenario is determined as the intersection of the modified generation and demand curves.

For example, in order to consider the case of the integration of an amount of renewable energy, ΔE_R, first the original hourly merit-order generation ($p_G = p_G(W)$) and demand ($p_D = p_D(W)$) curves are retrieved, as shown in Fig. 4. Since renewable generators offer energy at a very low (even null) price, the original bids corresponding to the renewable generation units can be found in the initial flat region (first steps) of the merit-order generation curve. The original renewable bids are now proportionally increased until the targeted amount (ΔE_R) is reached. When needed, the original hourly-cleared curves are completed with the single-bid curve from the initial clearing point onwards, as shown in Fig. 4. In this way, a new merit-order generation curve, $p_{GR} = p_{GR}(W)$, is created through the proper integration (upward price) of these modified bids in the generation curve. This new merit-order generation curve essentially results in a right-hand-shifting of the initial cleared supply curve by an amount equal to ΔE_R. Finally, the new clearing point (B in Fig. 4) can be determined as the crossing point of the new right-hand-shifted generation curve, $p_{GR} = p_{GR}(W)$, with the original demand curve, $p_D = p_D(W)$.

Fig. 4 also shows the case of the reduction of the demand in an amount of load, ΔE_L, due to, for example, energy saving for small consumers. Since small consumers demand energy at the highest price, their primitive bids are always found in the initial flat region of maximum price of the merit-order demand curve. The original bids of the small-consumer traders are then proportionally reduced until the targeted amount (ΔE_L) is reached. In this way, a new merit-order of reduced demand curve, $p_{DL} = p_{DL}(W)$, is created through the proper integration (downward price) of these modified bids in the demand curve. This new merit-order demand curve essentially results in a left-hand-shifting of the initial cleared demand curve by an amount equal to ΔE_L, as shown in Fig. 4. Finally, the new clearing point (C in Fig. 4) can be determined as the intersection of the new left-hand-shifted reduced-demand curve, $p_{DL} = p_{DL}(W)$, with the original generation curve, $p_G = p_G(W)$.

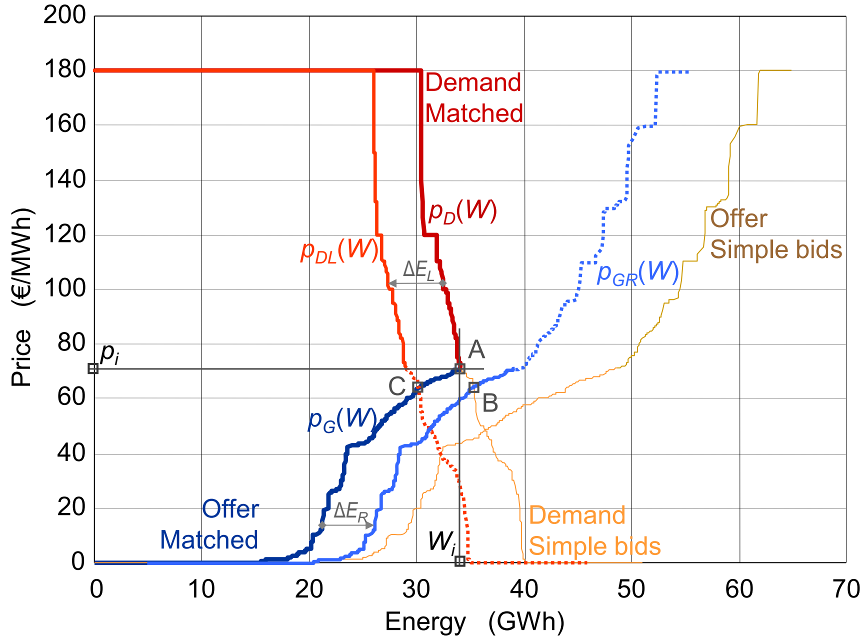

Fig. 4. Hourly merit-order generation, $p_G = p_G(W)$, and demand, $p_D = p_D(W)$, curves and creation of the new (right-shifted) renewable generation curve, $p_{GR} = p_{GR}(W)$, and of the new (left-shifted) reduced demand curve, $p_{DL} = p_{DL}(W)$.

Three scenarios are generated for 0.5%, 1% and 2% of load demand reduction as well as the symmetrical scenarios with growing of renewable energy. That gives place to a total of $6 \cdot 8760 = 52560$ hourly markets scenarios which must be simulated using the methodology described above. The obtained results are summarized in Table 1 and 2. More precisely, Table 1 summarizes the mean values of the variations of the annual traded energy, hourly clearing price and annual cost of the traded energy, while Table 2 shows the mean values of the rate of variation with the energy-saving and renewable bids of the annual traded energy, hourly clearing price and annual cost of the traded energy. As anticipated by the linear model approximation, the results lead to the following main conclusions:

- Energy efficiency: The mean values of the yearly traded energy, the hourly clearing price and the annual cost of the traded energy are always smaller than the corresponding to the base case, and their reductions grow almost linearly with the amount of load-saving bids.
- Renewables: The traded energy is always slightly greater that the corresponding to de base case and its increment grows with the amount of renewable bids. On the contrary, the clearing price and the cost of the traded energy are smaller than for the base case, and their reductions grow with the quantity of renewable bids.

  For the same amount of load-saving and renewable bids ($\Delta E_R = \Delta E_L = \Delta E$):

- The clearing price (and its variation) for energy efficiency is almost the same than for the corresponding renewable scenario, $\Delta p(\Delta E_R = \Delta E) \approx \Delta p(\Delta E_L = \Delta E)$.
- The intensity of the variation of the traded energy (absolute value), $\Delta W(\Delta E)/\Delta E$, and cost of the traded energy, $\Delta C(\Delta E)/\Delta E$, is always stronger for energy efficiency than for the corresponding renewable scenario. More precisely, the intensities are $(\Delta W(\Delta E_R)/\Delta E_R)/(|\Delta W(\Delta E_L)|/\Delta E_L) \approx 2.4$ and $(\Delta C(\Delta E_R)/\Delta E_R)/(\Delta C(\Delta E_L)/\Delta E_L) \approx 1.6$, respectively.

Table 1. Mean values of the variations of the yearly traded energy, hourly clearing price and yearly cost of the traded energy.

Spain 2014	Yearly mean	W = 221 TWh/y		p = 42.13 €/MWh		C = 9346 M€/y	
		ΔE = 0.5% Load (0.90 TWh/y)		ΔE = 1% Load (1.81 TWh/y)		ΔE = 2% Load (3.62 TWh/y)	
Small consumers	Units	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*
$\Delta W(\Delta E)$	GWh	-610.96	246.81	-1237.44	478.10	-2476.90	954.19
$\Delta p(\Delta E)$	€/MWh	-0.36	-0.36	-0.68	-0.68	-1.33	-1.33
$\Delta C(\Delta E)$	M€	-104.89	-66.56	-204.17	-128.09	-401.06	-251.22

$^*\Delta E_R = \Delta E_L = \Delta E$

Table 2. Mean values of the ratio of variation with the load saving or renewable bids of the annual traded energy, hourly clearing price and yearly cost of the traded energy.

Spain 2014	Yearly mean	W = 221 TWh/y		p = 42.13 €/MWh		C = 9346 M€/y	
		ΔE = 0.5% Load (0.90 TWh/y)		ΔE = 1% Load (1.81 TWh/y)		ΔE = 2% Load (3.62 TWh/y)	
Small consumers	Units	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*	Efficiency ΔE_L^*	Renewable ΔE_R^*
$\Delta W(\Delta E)/\Delta E$	-	-0.68	0.28	-0.67	0.28	-0.67	0.28
$\Delta p(\Delta E)/\Delta E$	€/MWh^2	$-3.81\cdot10^{-3}$	$-3.81\cdot10^{-3}$	$-3.34\cdot10^{-3}$	$-3.34\cdot10^{-3}$	$-3.05\cdot10^{-3}$	$-3.05\cdot10^{-3}$
$\Delta C(\Delta E)/\Delta E$	€/MWh	-116.54	-73.95	-226.86	-142.32	-445.62	-279.14

$^*\Delta E_R = \Delta E_L = \Delta E$

CONCLUSIONS

Renewables and energy efficiency put a downward pressure on the clearing price and the total cost of the traded energy in the wholesale market. These reductions are mainly related to the reduction of the cost of the fossil fuel necessary for the market operation, derived from the fossil fuel substituted (renewables) or avoided (energy efficiency).

This work has shown the results of comparing the potential economic impact in the Iberian electricity market of the integration of renewable production and energy efficiency. To reach that goal and to explore some basic hypotheses, first a qualitative model based on the linearization of the wholesale market, has been used. Then, the year 2014 has been analysed by using the hourly

Iberian Market information. An appropriate set of heuristic-based scenarios have been generated including integration of renewable generation as well as energy efficiency, in order to foreseen the main quantitative effects on the market performance.

The quantitative results of the heuristic-based scenarios confirm that, for the same amount of renewable and load saving bids, the efficiency scenario exhibits the best economic (reduction of traded energy, clearing price and traded energy cost) and environmental performance (fossil fuel displacement). The intensity of the variation with the load saving of the traded energy and cost of the traded energy are always stronger than for the corresponding renewable scenarios.

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Cement Plants: Carbon Risk and Optimal Retrofiting

Luis M. Abadie
Basque Centre for Climate Change (BC3)
Alameda Urquijo 4, 4º
48008, Bilbao, Spain
Tel. +34 94-401 46 90
E-mail: lm.abadie@bc3research.org
Néstor Goikoetxea
Escuela Técnica Superior de Ingeniera de Bilbao
Alameda Urquijo s/n.
48013, Bilbao, Spain
Tel. +34 94-601 40 24
E-mail: nestor.goikoetxea@ehu.eus
Ibon Galarraga
Basque Centre for Climate Change (BC3)
Alameda Urquijo 4, 4º
48008, Bilbao, Spain
Tel. +34 94-401 46 90
E-mail: ibon.galarraga@bc3research.org

Abstract

The cement sector is highly intensive in CO2 emissions and is the second most important industrial sector in terms of emissions from electricity generation. The cement sector not only emits CO2 from the combustion of fossil fuels, but also from the calcination process and, indirectly, from electricity consumption.

Efforts to reduce emissions in this sector become important in any climate change mitigation policy. Two different technologies are mainly used to produce clinker: the dry process and the wet one. The former is less energy intensive.

Several types of fuel can be used during the production process and include gas, oil, petcoke and coal, along with other alternative fuels such as biomass, tyres or industrial waste. Many of the alternative fuels are significantly cheaper but they are not always easily available.

This paper focuses on understanding the risk associated to the future price of EU ETS allowances for both wet and dry plants, and for combinations of traditional and alternative fuels. This is done by modelling a stochastic process with parameters calculated using market prices. Risks are valued using the Expected Shortfall (ES) and Value at Risk (VAR) during the lifetime of a plant. The paper includes a sensitivity analysis of the effects arising from jumps in the prices of allowances as a consequence of a hypothetical drastic change in climate policy. Finally, the paper includes the optimal conditions for retrofitting a wet cement plant to be converted to a dry cement plant under uncertainty of the price of carbon allowances. This is performed using the Real Options (RO) methodology.

The paper ends with the analysis of several alternative policies that could reduce emissions in clinker production.

Keywords: Cement Plants, uncertainty, carbon emissions, real options, expected

shortfall.

1 Introduction

The cement sector is highly emission-intensive, which, apart from the use of fossil fuels, is due to the calcination process itself to produce clinker that releases a considerable amount of CO_2. This sector is considered to be the second source of anthropogenic emissions in the world [1].
As can be seen in Figure 1 based on the 2014 Cembureau Activity Report [2], 56.5% of world cement production is in China. The economic crisis and technological improvements to cement production have recently led to a drop in emissions. This trend can be seen in Figure 2 for the EU(28) prepared using GNR Project-Cement Sustainability Initiative data [3].
Table 1 shows the long-term evolution for the EU(28) of the composition of the fuels used in the clinker production process. As can been seen, fossil fuel waste and biomass has gained in share over time and in 2013, fossil waste accounted for 25% and biomass 13.2% of fuels. This reflects an evolution towards greater sustainability.

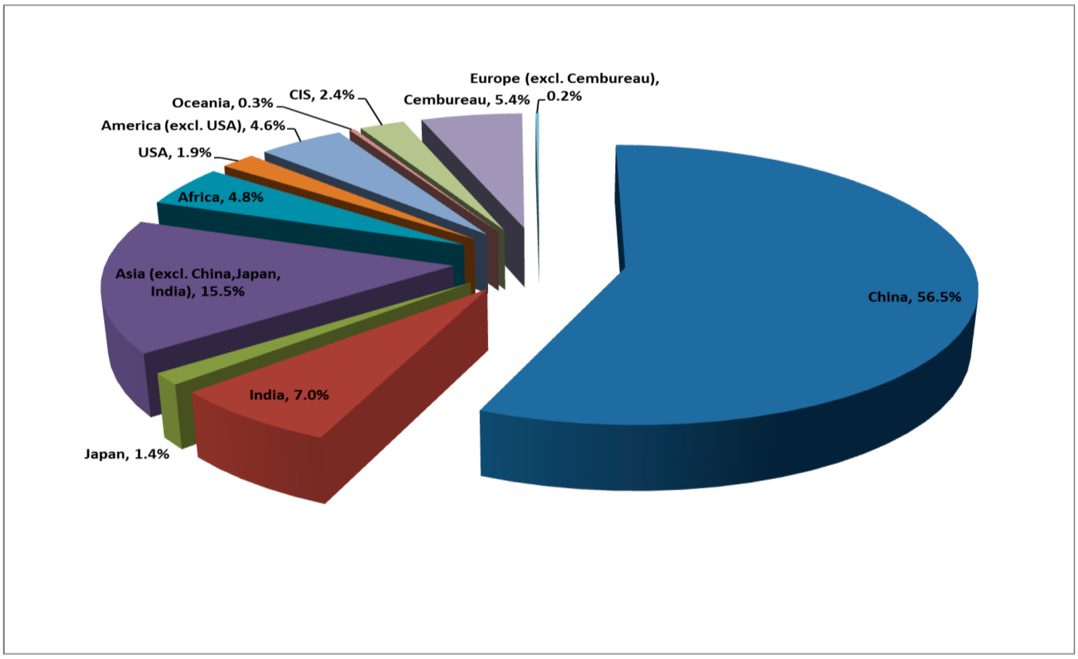


Figure 1: World cement production 2014, by region and main countries (%). Source: Prepared using data from the 2014 Cembureau Activity Report.

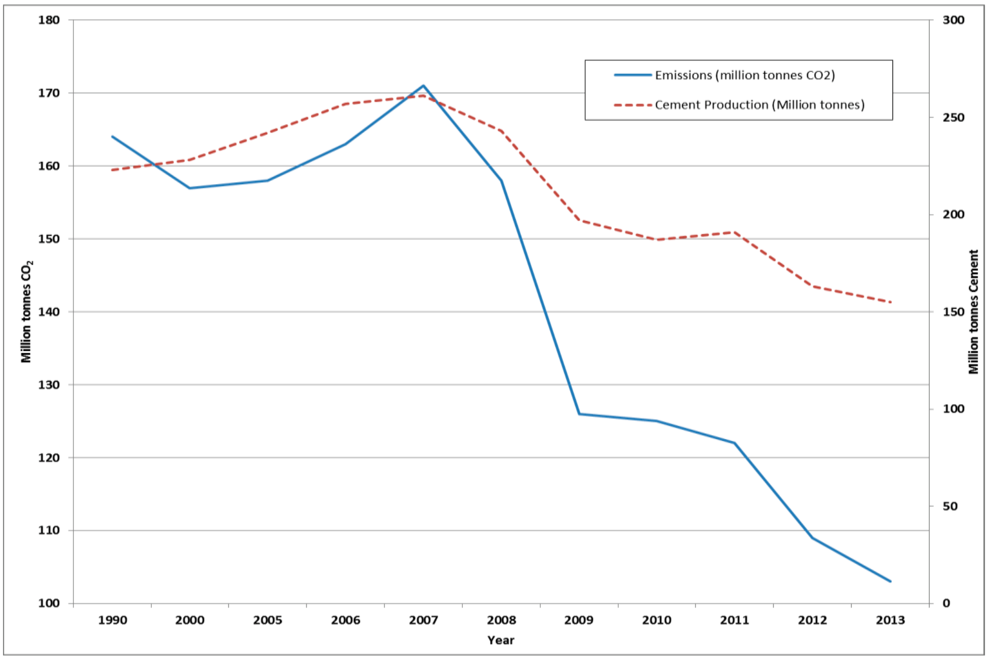


Figure 2: EU-28 (96% Coverage 2013) Grey and white cement production and emissions (excluding CO_2 from on-site power generation)
Source: Prepared used GNR Project-Cement Sustainability Initiative data.

Table 1: EU 28 Cement Plants Energy consumption in GJ and weighted average fuels

	Energy consumption (grey and white cement) in EU 28 GJ				weighted average - %total energy		
year	Fossil waste	Biomass	Fossil fuel	Total	Fossil waste	Biomass	Fossil fuel
1,990	15,950,790	1,527,993	719,717,929	737,196,712	2.2%	0.2%	97.6%
2000	49,926,614	9,028,415	611,655,833	670,610,862	7.4%	1.3%	91.2%
2005	73,437,064	25,526,798	580,536,115	679,499,977	10.8%	3.8%	85.4%
2006	94,801,150	31,854,404	574,722,020	701,377,574	13.5%	4.5%	81.9%
2007	109,318,171	31,738,749	597,665,771	738,722,691	14.8%	4.3%	80.9%
2008	112,928,557	36,396,292	537,084,427	686,409,276	16.5%	5.3%	78.2%
2009	119,321,039	35,032,885	398,368,097	552,722,021	21.6%	6.3%	72.1%
2010	131,757,284	33,612,772	380,140,775	545,510,831	24.2%	6.2%	69.7%
2011	136,618,459	47,484,574	359,515,557	543,618,590	25.1%	8.7%	66.1%
2012	124,063,320	52,971,428	312,598,114	489,632,862	25.3%	10.8%	63.8%
2013	115,224,304	60,859,047	285,614,348	461,697,699	25.0%	13.2%	61.9%

Source: (GNR) "Getting the number right" Cement Sustainability Initiative

The cement industry in Europe has now replaced a large part of fossil fuels. Some plants are using 80% alternative fuel. It has been estimated that by 2050, 40% of kiln energy could potentially come from traditional sources, i.e. coal (30%) and petcoke (10%), while 60 % of kiln energy consumption could potentially be provided by alternative fuels, 40% of which could be biomass. A number of policy modifications are required according to the authors of *The role of Cement in 2050 Low Carbon Economy* [4] in order for this level of reduction to be achieved.

The calcination process releases significant amounts of CO2 and some authors have proposed opting for carbon capture and storage (CCS) to cut this type of emissions. Thus, Barker et al. (2009) [5] study technologies that can be used to capture CO2 from cement plants, their costs and the barriers for their use. Benhelal et al. (2013)[6] study the energy and emissions savings due to changes towards a more efficient process and consider CCS as an effective means to reduce CO2 emissions.
On the other hand, the captured CO_2 in cement plants could be used for Enhanced Oil Recovery processes, even though there has been an appreciable drop in the price of oil (2015) .
Romeo et al. (2011) propose using industrial symbiosis to combine/integrate a power plant, a cement plant and a CO_2 capture system.
Ali et al. (2011)[8] review the emission sources in the cement industry, together with different techniques to reduce them. These authors conclude that a considerable amount of emissions in this industry may be mitigated using different savings measures and techniques.

Hasanbeigi et al. (2012) [9] study the information available on eighteen emerging technologies for the cement industry regarding process description, energy savings, environmental and other benefits, costs, commercialization status, and references for emerging technologies to reduce the cement industry's energy use and CO_2 emissions.
Hurme and Kajaste (2016) [10] analyse the regional CO2 emissions of cement plants, conclude that mineral components reduce emissions fast and that carbon capture and geo-polymers are the futures. The abatement costs are compared.
Xu et al. (2012) [11] analyze the change in energy consumption and CO2 emissions in China's cement industry and its driving factors. Cai et al. (2015) [12] evaluate the overall CO_2 emissions from the cement industry based on the detailed information of China's total 1574 cement enterprises in 2013. They conclude that ownership of cement companies should be carefully considered in policy preparation.
Pardo et al. (2011)[13] analyze three scenarios: baseline scenario (BS) representing the current evolution of the cement sector and two alternative scenarios (AS1 and AS2) studying the sensitivity of fuel prices and CO_2 emission prices, respectively.
Naranjo. et al. (2011) [14] present the groundwork for the development and demonstration of a commercial-scale CCS project at one of CEMEX Inc.'s U.S. cement plants.
Liang and LI (2012)[15] analyses the economics of retrofitting cement plants for CCS with a case study of a modern dry process cement plant located in Guangdong, China.
García-Gusano et al. (2015) discuss the evolution of the cement industry in Spain using cement demand projections and an energy optimization model.
This paper has a very different approach from that of previous works, as it starts from a cement production model with its fuel consumptions (traditional, alternative and biomass) and their relevant carbon emissions, but it applies a stochastic model consistent with the market prices for investment and risk appraisal and real options valuation of cement plants. It is therefore an optimisation and valuation model under uncertainty.

Apart from the fuel costs, the cement industry is facing uncertainty about the price of the emission allowances and even uncertainty about the amount of rights that may be freely allocated.

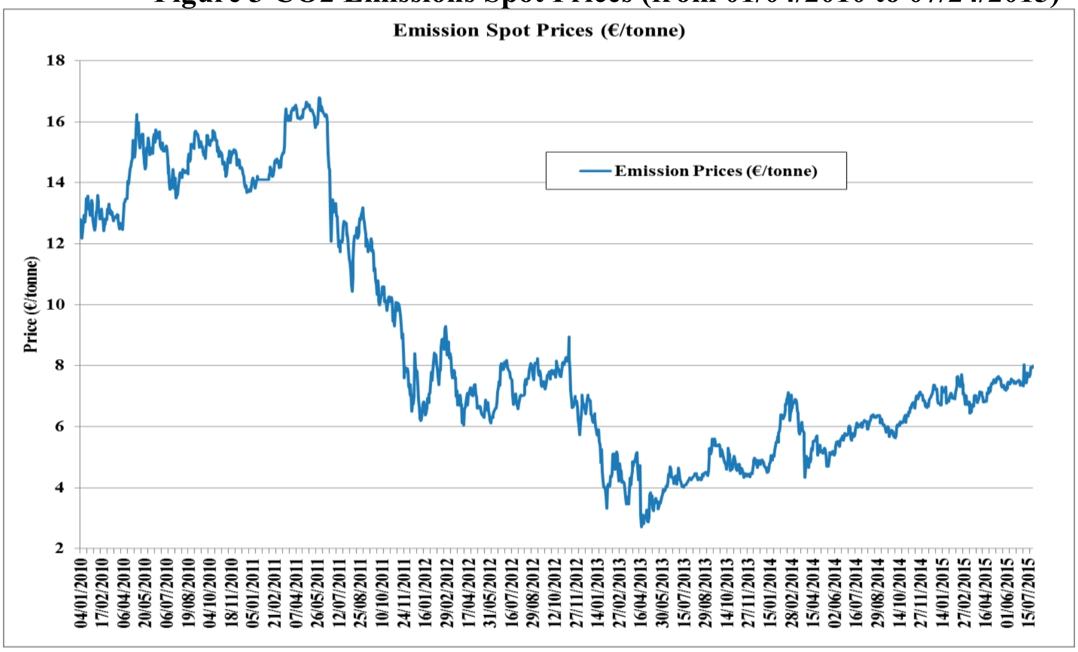
The rest of the paper is structured as follows: Section 2 focuses on carbon prices, their stochastic model, the calculation of the parameters, the risk model and the fuel prices. Section 3 considers the cement production technologies, their emissions per tonne of clinker, fuel consumption and its cost. Section 4 addresses the calculation of the carbon price risk for two types of technologies (Wet and Dry). This risk assessment is conducted for the two technologies, using the Expected Shortfall (ES) to measure the risk and according to the remaining useful life of the facility. Section Four also explores the impact of a jump in the price of the emission allowances and includes the possibility of removing part of the free delivery allowances as a favourable technological development occurs from the point of view of the emissions. Section Five studies the real option of retrofitting a wet plant to a dry plant. Section 6 concludes.

2 Emission and Fuel Prices

2.1 Carbon Prices

Figure 4 reflects the evolution of emission spot prices from 01/04/2010 to 07/24/2015, with periods of high volatility and a general upward price trend in the last months, with a spot price of S_0=7.99 €/tonne on the last day of the series. It can be concluded that the spot prices are very low, but very volatile. The low carbon prices and their high volatility do not greatly stimulate investments in mitigation such as improvements in energy efficiency (Abadie and Chamorro, 2008) [17].

Figure 3 CO2 Emissions Spot Prices (from 01/04/2010 to 07/24/2015)



The Volatility is a manifestation of uncertainty. It plays a determining role when valuing real options and risk. It is usually calculated as the standard deviation of the log of the yields:

$$R_t = \ln\left(\frac{S_t}{S_{t-1}}\right) \tag{1}$$

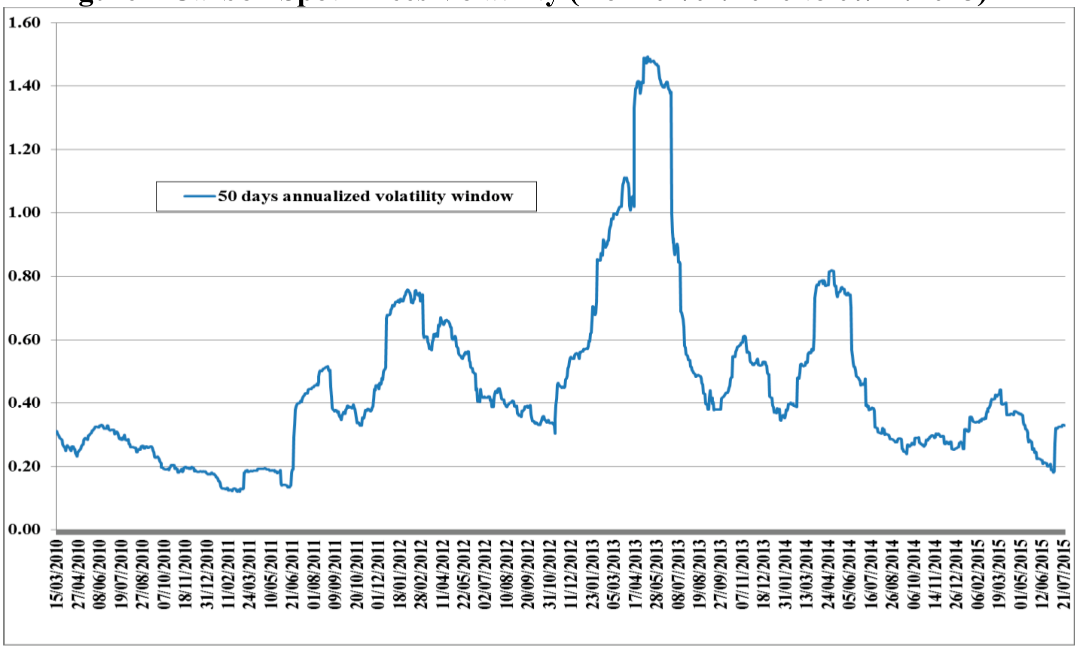
This gives the value of σ_d. to obtain the annualized volatility σ the following is used:

$$\sigma = \sigma_d \sqrt{252} \tag{2}$$

where 252 is the number of trading days.

Figure 4 shows the volatility prices using a 50-day window. The last value is σ=0.3294.

Figure 4 Carbon Spot Prices Volatility (from 01/04/2010 to 07/24/2015)



2.2 Stochastic Emission Price Model

In the real world the model is as follows:

$$dS_t = \alpha S_t dt + \sigma S_t dW_t \tag{3}$$

where S_t is the carbon price at time t, α is the drift in the real world, σ is the instantaneous volatility and dW_t stands for the increment to a standard Wiener process. The risk-neutral version of the model is:

$$dS_t = (\alpha - \lambda) S_t dt + \sigma S dW_t \tag{4}$$

where λS_t is the market price of risk. Kolos and Ronn (2008) [18] estimate the market price of risk for energy markets.

It holds that $\alpha - \lambda = r - \delta$ with r being the risk-free rate and δ the convenience yield, so the following alternate expression can also be used:

$$dS_t = (r - \delta)S_t dt + \sigma S dW_t \tag{5}$$

If $X = \ln S$, and Ito's lemma is applied, then the following is obtained:

$$dX_t = (\alpha - \lambda - \frac{\sigma}{2})dt + \sigma dW_t \tag{6}$$

In this case, the value of a future with maturity T at time t is obtained from the following equation:

$$F(t,T) = S_t e^{(\alpha-\lambda)(T-t)} = S_t e^{(r-\delta)(T-t)} \tag{7}$$

Equation (7) shows that a commodity with GBM-type behaviour in the spot price should exhibit prices on the futures market that increase by larger amounts in absolute value as the maturity period increases. This behaviour can be used to identify whether a commodity such as carbon is a good candidate for GBM modelling.

Figure 5 and Table 2 show the estimated values of $\alpha - \lambda$. We can estimate the trend using the prices of the 2015 futures market included in the sample, where we obtained: α-λ=0.0219, which shows low growth of the futures prices as the maturity increases.

Table 2: Drift (α-λ) Estimate			
Coefficient	Std. Error	t-ratio	p-value
0.0218957	0.000270708	80.8829	<0.00001 ***

Figure 5 Drift daily estimate

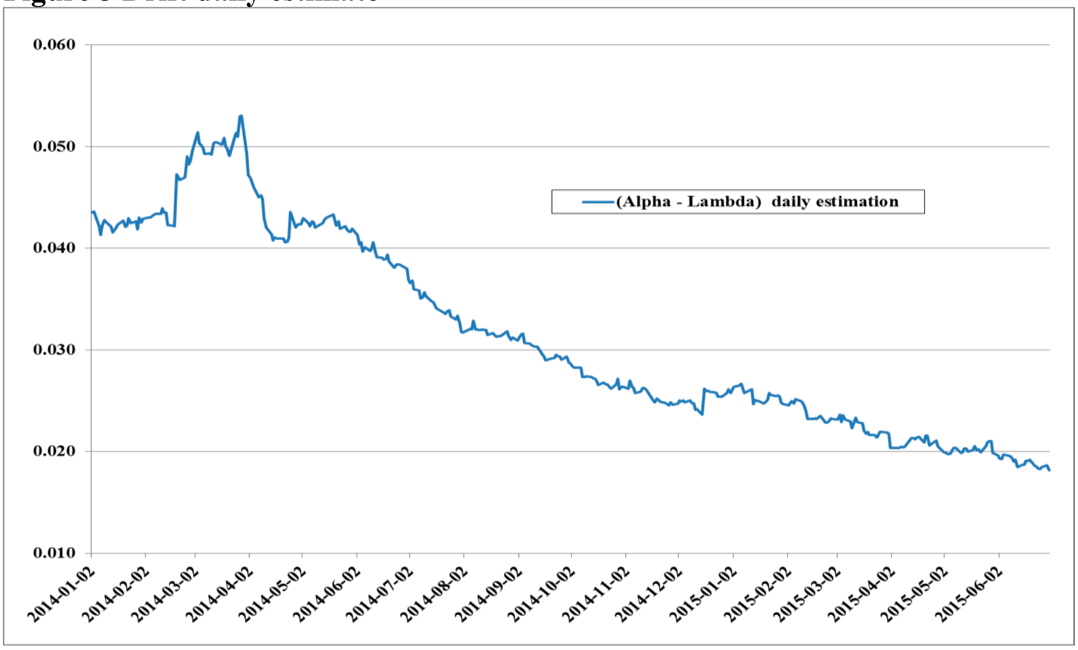
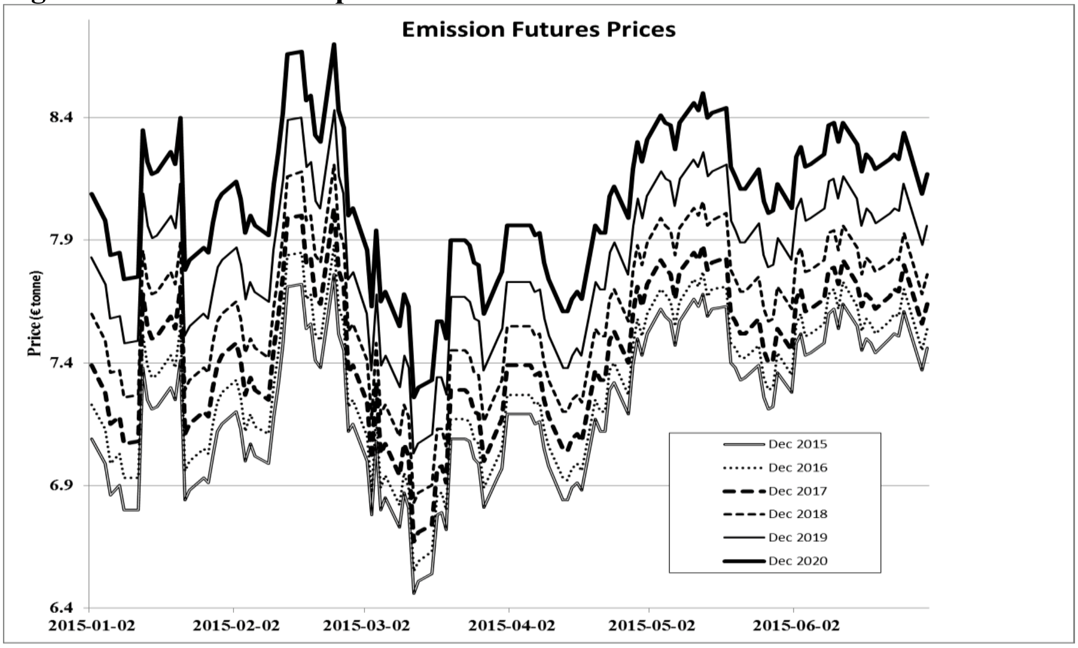


Figure 6 shows the evolution of the futures prices for different maturities

Figure 6 Carbon futures prices



Another parameter needed is the risk-free rate r and we are going to take the July 2015 interest rate of the 10-year German public debt: r=0.0071.

Table 3 summarises the values of the stochastic emission price model parameters:

Table 3: Parameters gbm model	
Parameter	Value
S0	7.99
α-λ	0.0219
σ	0.3294
r	0.0071
τ_1	0
τ_2	25

The present value of a tonne of CO2 emitted every year between τ1 and τ2 is (Abadie and Chamorro, 2013)[19]:

$$V(\tau_1, \tau_2) = S_0 \frac{(e^{(\alpha-\lambda-r)\tau_2} - e^{(\alpha-\lambda-r)\tau_1})}{\alpha - \lambda - r}$$

The results in Table 4 are obtained for the case of a cement plant according to its remaining useful life.

Table 4: CO_2 emissions cost and remaining useful life per tonne CO_2/year	
Remaining useful live (years)	Present Value CO2 cost (€)
25	241.72

30	301.75
35	366.39
40	435.99

2.3 The risk model

Value at Risk (VaR): This is a measurement for calculating and managing risk that is widely used for finding the expected value of a portfolio V . It needs two elements: a time-frame $T-t$ and a confidence level $x\%$. It is based on calculating a value a such that in $x\%$ of cases the expected value of the portfolio is $E_t(V_T) > a.$ The values of $x\%$ usually used are 95%, 97.5% and 99%.

Expected shortfall (ES): This is the expected value in those cases in which the value obtained is lower than Var(x%).

However, despite its widespread use, VaR has poor mathematical properties for optimisation applications as it is non-convex.

It is considered that a coherent risk measurement $R(D)$ in which D represents the losses or damage must meet the following four conditions: monotonicity, sub-additivity, positive homogeneity and translation invariance[2]:

a) monotonous: $R(D) \leq 0$.
b) Sub-additive: $R(D_1+D_2) \leq R(D_1)+R(D_2)$.
c) Positive homogeneous: $R(kD)=kR(D)$.
d) Translation invariant: $R(D+l)=R(D)-l$.

VaR as a measurement of risk lacks several desirable properties: it is not subadditive and, consequently, it is not coherent in the sense of Artzner et al. (1999).

Expected Shortfall (ES) is however a coherent risk measurement, as it meets all the above conditions. ES is the expected value when the damage is greater than VaR (x%) for the case of the damage considered here.

2.4 Fuel Prices

2.4.1.-Petcoke

[2] Where risk is represented by a negative value.

The price of high sulphur petcoke is 40-45 USD/tonne FOB US Gulf (2014 Cembureau Activity Report) [2]. The price of mid sulphur petcoke is 55 USD/tonne. This type of petcoke is not used as it more expensive that the high sulphur one and, furthermore, the clinker takes up all the sulphur in the calcinations process and it therefore has little impact on the SO2 emissions. Curiously, the fluctuations in petcoke price depends on aluminium. This is because electrodes need to be used when manufacturing aluminium to carry out the electrolysis and those electrodes are made from petcoke. Venezuela is a great producer of petcoke and the range in the price of petcoke is considerable and fluctuates greatly. It has even dropped to 6 USD/tonne at times.
We use 42.5 USD/tonne and, with an average exchange rate for 2014 of 1.3286 $/€ (European Central Bank), we therefore have a price of 31.99 €/tonne.

2.4.2.- Alternative Fuel and Biomass

For alternative fossil fuels: 22 €/tonne.
For biomass fuels: 20 €/tonne.
Source for both cases: Cement company information.

3 Emission from cement plants (Cement Plant Model) bottom-up

There are four processes to manufacture cement: dry, semi dry, semi-wet and wet processes. The main differences primarily depends on the state of the raw materials, whether they are dry or wet. Therefore, the higher the moisture content, the more energy is consumed.
A large part of world clinker production depends on wet processes. However, 75% of the processes in the European Union are dry for grey cement.

As can be seen in Table 5, the dry process has increased its share in Europe from 72% in 1990 to 84% in 2013, and the share of the Dry Process with Preheater and Preclainer has particularly risen.

Table 5: EU(28) total production grey cement for kiln type

Year	Total Dry	Dry with preheater and precalciner	Dry with preheater without precalciner	Dry without preheater (long dry kiln)	Mixed kiln type	Semi-wet /semi dry	Wet / Shaft kiln
1990	72%	26%	40%	6%	-	16%	12%
200	75%	36%	36%	3%	12%	12%	-

0							
2005	77%	42%	32%	3%	10%	9%	5%
2006	77%	43%	31%	3%	9%	8%	5%
2007	78%	43%	32%	3%	9%	8%	5%
2008	79%	43%	33%	3%	9%	8%	5%
2009	81%	46%	32%	3%	8%	7%	4%
2010	82%	44%	33%	5%	8%	7%	4%
2011	82%	44%	33%	5%	7%	7%	5%
2012	82%	46%	29%	7%	6%	8%	3%
2013	84%	48%	29%	7%	6%	8%	3%

Source: Prepared using data from the Cement Sustainability Initiative (CSI) GNR Database

A cement plant directly produces emissions related to:

a) The calcinations process.

b) Combustion of kiln fuels in clinker production that can be a) conventional fossil fuels, b) alternative fossil fuels and mixed fuels with biogenic carbon content and c) biomass fuels and biofuels.

c) Indirect Emissions.

In the other hand, in order to ensure proper and reasonable calculations, the prototype kiln is the one which produces 3,000 tonnes per day, which is close to 1,000,000 tonnes per year.

3.1 Emissions from raw material calcination (output method)

The method we are going to use is the one based on clinker output, i.e. the output method.

Emissions are produced by the calcination process itself and the combustion of the organic carbon in the raw material, with CO_2 being released into the atmosphere according to Equations (8) and (9):

$$CaCO_3(+950^o C) \rightarrow CaO + CO_2 \uparrow \quad (8)$$

$$MgCO_3(+950^o C) \rightarrow MgO + CO_2 \uparrow \quad (9)$$

where $CaCO_3$ is calcium carbonate, $MgCO_3$ is magnesium carbonate, CaO is calcium oxide and MgO is magnesium oxide.

In the absence of better data, a default of 525 kg CO2/t clinker is recommended by the Cement Sustainability Initiative (CSI) as the Simple output method B1[20]. This value is comparable to the IPCC default [21](510 kg CO2/t) corrected for typical MgO contents in clinker, which is usually 2%.

The IPCC method correlates with a default CaO contained in clinker of 65% including a 2% correction for discarded dust.

$$0.785 \times FractionCaO = 0.785 \times 0.65 = 0.510\,\mathbf{tCO_2/tclinker} \tag{10}$$

where 0.785 is (44.01 g/mole CO2)/(56.08 g/mole CaO).

IPCC recommends 2% for discarded dust which means $0.525 \times 1.02 = 0.5355$ t CO_2 / t clinker. In addition, the CO2 from organic carbon in raw material per clinker unit is included:

$$1.55 \times FactionOrganic \times \frac{44}{12} \tag{11}$$

where 1.55 is the raw material to clinker ratio, $Faction\ \ Organic$ is is the fraction of total organic carbon in the raw material, with a defaut value of 0.2%. The $\frac{44}{12}$ is the conversion between CO_2 and C. In short, we have in the calcination process:

$$EF_c = 0.547\,\mathbf{tCO_2/tclinker} \tag{12}$$

where EF_c [3]is the emission factor per tonne of clinker corresponding to the calcination process.

The B1 simple output method can be performed entirely in the plant sheet and no separate auxiliary sheet is required.

This value it is a realistic approximation, although it can vary from place to place as the CaO content can vary from region to region and also due to the ratio used in the recommended adjustment of the lost cement kiln dust (CKD) which is around 2-6%.

3.2 Emission from Conventional Fuels

The energy demand for clinkerization in the dry process is 3500 MJ/tonne clinker
The energy demand for clinkerization in the wet process is 3500 MJ/tonne clinker
The combustion emission factor depends on the types of cement production processes, fuels used and energy efficiency.

[3]0.785=(44.01 g/mole CO2)/(56.08 g/mole CaO).

The fossil fuels can be coal, petcoke, fuel oil or natural gas, but natural gas is not used in practice due to its high price. The possibility of using alternative fuels will help to save natural resources. Characteristics of the clinker burning process itself provide environmentally beneficial waste-to-energy aspects.

Table 6 shows the emission factors of the fuels (F_f) and the gross calorific value of fossil, alternative and biomass fuels.

Table 6: Fuel Emissions and PCS Fossil, alternative and biomass fuels

Category	IPCC default (1)(2) KgCO2/GJ	PCS (Gross Calorific value) KJ/ Kg
Fossil fuels		
Coal – anthracite	96.1 – 98.3	24,500 (3)
Petroleum coke	97.5	34,100
(Ultra) heavy fuel	77.4 *	43,000
Diesel oil (Bunker oil)	74.1	44,800
Natural gas (dry)	56.1	43,000
Oil shale	107	-
Lignite	101	18,400 (3)
Motor gasoline	69.3	47,300
Alternative Fossil fuels (simple average)	94.76	23,217
Waste oil (lubricants)	73.3	34,100 (3)
Tyres	143	29,900 (3)
Plastics	75*	31,000 (3)
Solvents	74*	21,000
Impregnated saw dust	75*	22,600 (3)
Mixed industrial waste	143	28,603
Other fossil based wastes	80*	-
Biomass Fuels (simple average)	97.71	14,825
Dried sewage sludge	54.6	10,000
Wood, non impregnated saw dust	112	15,900
Paper, carton	110*	15,000
Animal & bone meal	100	18,400
Agricultural, organic, diaper waste, charcoal	100 - 112	-
Other biomass	95,3 - 112	-

(1) 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

(2) 2011 - 2014 by WBCSD Cement Sustainability Initiative (CSI) /ECRA GmbH Cement CO2 and Energy Protocol.

* Nota: The values proposed by IPPC 2006 have been taken as the default ones and those of the CSI have been taken in the case the former were not defined.

(3) The simple average have been taken for the case of values contained in a range.

The CO_2 emissions from biomass fuel are considered to be climate-neutral and are therefore excluded from the emissions totals. However, CO_2 emissions from fossil fuel derived wastes (also called alternative fossil fuels or fossil AF) arenot a priori climate neutral.

We need 3,500 MJ/ tonne of clinker in the dry process and 6,500 in the wet process

Table 7 shows the emissions from fuel consumption per tonne of clinker using the 2013 mix of Table 1:

Table 7: Fuel cost and emissions per tonne clinker Wet and dry Process							
				Wet Process		Dry Process	
Product	Mix	PCS (J/kg)	Emissions (Kg CO_2/GJ)	Fuel cost (€)	Emissions (Kg)	Fuel cost (€)	Emissions (Kg)
Pet coke	61.8%	34,100	97.50	3.77	391.66	2.03	210.89
Alternative fuel	25.0%	23,217	94.76	1.54	153.98	0.83	82.92
Biomass Fuel	13.2%	14,825	0.00	1.16	0.00	0.62	0.00
TOTAL	100.0%	28,835		6.47	544.64	3.48	293.81

The costs in the dry process are therefore lower and there are savings of a quarter of tonne of CO_2 for each tonne of clinker produced. If a typical plant produces 3,000 tonnes/day of clinker, which is roughly equivalent to a million tonnes/year of clinker, the savings in emissions in the fossil fuel combustion from changing from a wet to dry process would be 250,830 CO2 tonnes/year and if the remaining life is 25 years, the savings would be nearly 6.27 million tonnes of CO_2.

3.3 Combustion of fuels for on-site power generation.

Emissions of CO_2 mainly come from combustion of fossil fuels and from calcination of limestone into calcium oxide. An indirect amount of CO_2 comes from the consumption of electricity that is generated by burning fossil fuels. Electricity consumption mainly occurs in the grinding operations, both of the raw materials prior to their burning, and of the clinker and the additions to obtain cement. Both operations together account for around 75% of the electricity consumed in the factory and the other 25% is used for transporting materials, gas impulsion and electro-filters.

We think it is important the specific power total consumption in a plant. So we have to take into account this task. We can break down electric consumption into three areas:

1.-Pre burning: Crushing and milling: "After the raw materials, which have different mineralogical and chemical characteristics and some of which are delivered in large pieces, have been extracted from the mining operations, the raw materials have to be turned into a powder for the burning process. This is achieved by crushing, sieving, drying, grinding, mixing and transporting solids."

The preparation of the crude mixture is sufficient in itself for there to be serious interest in it, as the energy consumed is 21-25 KWh/t crude mixture or 32-39KWh/t clinker.

2.-Burning: Fans and coolers, and dust collector

3.- Grinding and bagging: cement milling and transportation

Electrical energy used can be minimized by the use of energy efficient equipment.

According to [6] specific electrical energy consumptions in the dry and wet processes are, per unit Kwh/cement:

Table 8: kWh/tonne cement		
	DRY PROCESS	WET PROCESS
1.-	48	63
2.-	29	33
3.-	53	53
Total	130 KWh/tonne cement	149 KWh/tonne cement

According to [7] the electrical energy consumption of a modern cement plant is about 110-120 KWh per tonne of cement.

According to [8] the consumption of electric energy in the Polish cement industry fell from 105 in 2002 to 94 KWh per tonne of cement in 2008.

A conversion factor, which depends on the plant, has to be applied to change these values to the kWh/tonne of clinker unit. If we take a clinker conversion factor in the cement of 0.756, the consumption is 154.76 KWh/tonne clinker in the dry process and 197.10 kWh/tonne clinker in the wet process.

There is electricity consumption of 197.10 kWh/tonne clinker in the wet process and 154.76 kWh/tonne clinker in the dry process. The indirect emissions from electricity consumption are 0.033 tonne of CO_2/tonne clinker in the wet process and 0.026 tonne of CO_2/tonne clinker in the dry process.[4]

3.4 Total emission and cost

Table 9 shows the total emissions with the three sources for the two types of process:

Table 9: Total emissions/tonne clinker		
	Wet Process	Dry Process
Calcination	0.547	0.547
Fuel Consumption	0.546	0.294
Electricity	0.033	0.026
Total	**1.125**	**0.866**

If we initially consider emission allowances of 0.766 tonnes CO2/tonne of grey clinker, the

[4] Some cement plants have been adopting new power generation technologies using waste heat recovery (WHR) to self generate electricity. As a result, the electricity consumed from WHR power generation should be excluded from the electricity-related emission factors”. In this study we are not taking this into account.

costs would be 0.100 tonnes CO2/tonne clinker in the dry process of grey clinker y de 0.359 tonnes CO2/tonne clinker in the wet process. The emission allowance for electricity consumption is considered to be paid within its cost and that the price of those allowances is indirectly passed on to the clinker manufacturing.

If we consider that the fuel price grows at the risk-free interest rate r and that the expected value of the price of the emissions is that of its stochastic process, we initially have a real value of the costs per tonne of clinker for a remaining useful life as set out in Table 10:

Table 10: Total cost with remaining useful life			
Useful Remaining Life (years)	Cost (millions €)	Wet Process	Dry Process
25 years	Total (millions €)	248.51	111.33
	. Fuels	161.64	87.04
	. Emissions	86.86	24.29
30 years	Total (millions €)	302.41	134.77
	. Fuels	193.97	104.45
	. Emissions	108.44	30.32
35 years	Total (millions €)	357.97	158.68
	. Fuels	226.30	121.85
	. Emissions	131.67	36.82
40 years	Total (millions €)	415.31	183.08
	. Fuels	258.63	139.26
	. Emissions	156.68	43.82

Changing from wet to dry process means a saving over 30 years of €167.64 per tonne of clinked produced per year (€89.52 Fuel Cost and 78.12 Emission allowances). It must be taken into account that the cost increases each year due to the emission allowances whose expected value would increase over the risk-free rate. The values of Table 10 would have to be multiplied by the annual production to obtain the total cost. Thus, if the production of the plant is a million tonnes/year, the current value of the savings over 30 years would be around EUR 167.64 million The savings for 25 years of remaining useful life would be 137.18 €/tonne clinker and we are going to take 25 years as the standard case from here onwards, even though the proposed model can be adapted to a different number.

4. The Carbon Price risk in a cement plant

We can simulate the different equiprobable trajectories of the performance of the prices of the emission allowances by using a Montecarlo simulation.

$$S_{t+\Delta t} = S_t e^{\left(\alpha-\lambda-\frac{1}{2}\sigma^2\right)\Delta t+\sigma\sqrt{\Delta t}\varepsilon_t}, \tag{13}$$

The final values obtained must be close to the theoretical average and variance:

$$E_0(S_{25}) = S_0 e^{25(\alpha-\lambda)} = 13.81 \tag{14}$$

And the typical deviation

$$S_0 e^{25(\alpha-\lambda)}\sqrt{e^{\sigma^2 t}-1} = 51.81 \qquad (15)$$

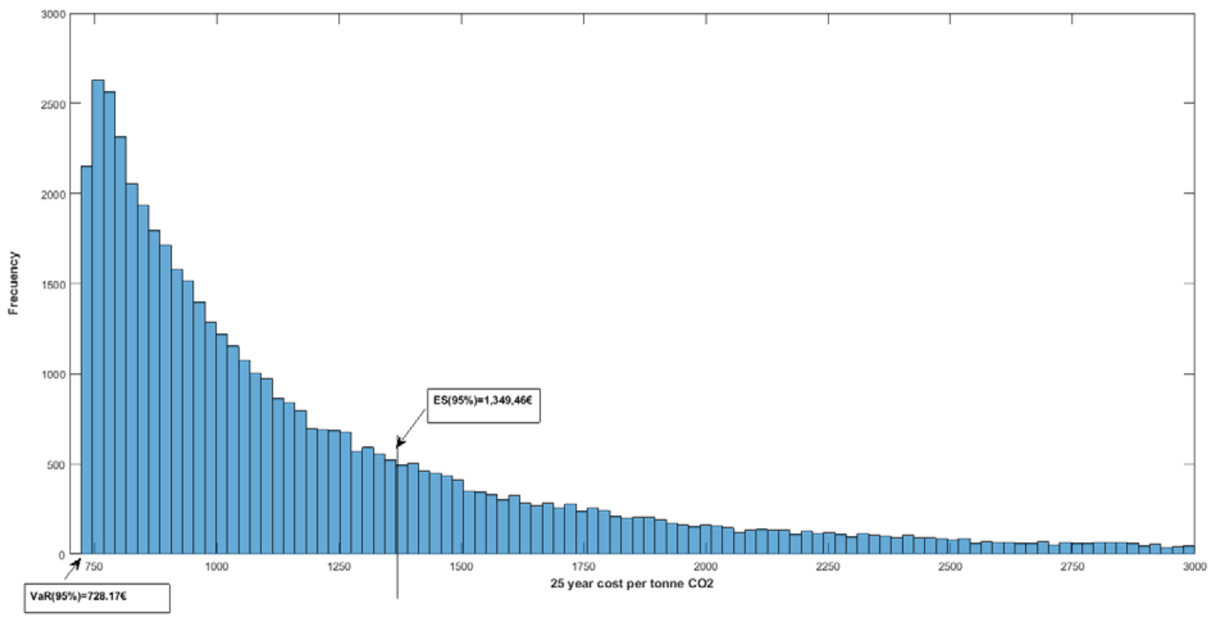
The values obtained using by simulating a million trajectories are €13.80 and 51.39. The current value of a yearly emission allowance over 25 years is €241.68, a figure that is very close to the theoretical value of €241.72. Values for the VaR (95%)=€728.17 and ES(95%)=1349.4 are obtained. In other words, while the annual average per tonne over 25 years is €241.68, it would exceed €728.17 in 5% of cases and when this value is exceeded, the average will be 1349.46, which is the result of the high volatility of carbon prices, which involves a considerable risk. As already analysed, we need 0.100 tonnes CO2/tonne clinker for a dry process, while it is 0.359 tonnes CO2/tonne Clinker for a wet process, which gives the values of Table 11:

Table 11: Carbon Risk Cement Plant per tonne clinker/year

	Carbon Price Risk	Wet Process Risk	Dry Process Risk
Mean	241.68	86.76	24.17
Value at Risk VaR (95%)	728.17	261.41	72.82
Expected Shortfall (95%)	1349.46	484.46	134.95

The risk of each specific plant would have to be multiplied by its annual clinker production, for example, by a million if that is the annual production. Changing from a wet to dry process reduces the risks notably. Figure 7 shows the distribution of the 5% worst cases.

Figure 7: Queue log-normal distribution 95th percentile



We are now going to experiment with a more complex risk model:

a) Let us assume that there is also a 50% probability in 2020 (within five years) of withdrawing 0.100 emission allowance per tonne of clinker which would then be auctioned.

b) In 2020, there could be a jump in the price of emission allowances with an expected value of 5 euros/tonne COS and 0.20 volatility in the jump. In other words, the jump has a normal distribution.

c) This is all superimposed on the stochastic model used.

For t=5 we have before the possible jumps:

$$S_5^- = S_{5-\Delta t} e^{\left(\alpha-\lambda-\frac{1}{2}\sigma^2\right)\Delta t+\sigma\sqrt{\Delta t}\varepsilon_t}, \qquad (16)$$

And after the jump.

$$S_5^+ = S_5^- + J \qquad (17)$$

Where $J_t = J(\mu_J, \sigma_J)dq$, μ_J is the expected value of the jump, σ_J is the volatility of the jump and dq has a value of 1 with probability when t=5 and 0 otherwise.

On the other hand, the withdrawal, with 50% probability, would affect the allowances needed per tonne of clinker that could be 0.200 for dry process and 0.459 for wet process.

Table 11: Carbon Risk Cement Plant per tonne clinker/year (With Jumps)

	Wet Process Risk	Dry Process Risk
Mean	142.48	50.89
Value at Risk VaR (95%)	409.59	152.34
Expected Shortfall (95%)	733.34	278.70

As can be seen in Table 11, the risks have increased considerably, which would make the dry process comparatively more favourable than the wet process from the carbon risk price perspective, as the risks have increased more in the wet process than in the dry process. Greater uncertainty increases the risks of the less efficient technologies.

5. The Option of retrofit a wet plant to a dry plant

With 25 years of remaining useful life, retrofitting a wet plant to a dry plant means a net present value of the savings obtained (emission allowance and fuel) of 137.18 million, it could seem in principle that if the current values of the costs / of retrofitting the cement plant is inferior to this figure as the Net Present Value (NPV) is positive, the decision would be to make the investment immediately. However, it may not be the optimum investment moment under uncertainty and the optimum moment by applying the Real Option is usually when the cost is lower to a frontier value or trigger price (I*).

To calculate this value, we construct a binomial tree that represents the performance under uncertainty of the price of the emission allowance. In our case, we therefore initially have a remaining life of T, and we use a size of the step from $\Delta t = \frac{1}{60}$; which is equivalent to 60 steps per year or 5 steps more month. If we invest the savings in the plant that occur during the rest of its remaining life, the savings A(t,S) for a plant that produces (P) a million tonnes of clinker a year will initially be:

$$A(T,S_0) = S_0 P(1.125-0.866)\frac{(e^{(\alpha-\lambda-r)T}-1)}{\alpha-\lambda-r} + P\times T(6.47-3.48) \quad (18)$$

Where the first summand is the current value of the emission allowance price saved over T years, with 1.125-0.866 being the number of rights saved per tonne of clinker.

The second summand is the fuel saving.

When the time advances within the binomial tree and n steps have elapsed, the saving is lower due to a shorter remaining time T-t=T-nΔt, but the initial price of the emission allowance may have taken another value S_t, which can be inferior or superior. In this case, the saving in an intermediary node of the binomial tree would be:

$$A(T-t,S_t) = S_t P(1.125-0.866)\frac{(e^{(\alpha-\lambda-r)(T-t)}-1)}{\alpha-\lambda-r} + P\times(T-t)(5-2.69) \quad (19)$$

After one period, the emission allowance price can go either up or down:

$$S^+ \equiv uS = S_0 e^{\sigma\sqrt{\Delta t}}, \quad S^- \equiv dS = S_0 e^{-\sigma\sqrt{\Delta t}}, \quad (20)$$

with probabilities:

$$p_u = \frac{e^{(\alpha-\lambda)\Delta t} - e^{-\sigma\sqrt{\Delta t}}}{e^{\sigma\sqrt{\Delta t}} - e^{-\sigma\sqrt{\Delta t}}}, \quad p_d = 1 - p_u, \quad (21)$$

First we assess the decision to invest at the end. Thus, if we have the option to invest at the expiration moment T and the cost of the investment is I we have: NPV=A(0,S_T)-I and our decision is $\max(A(0,S_T)-I,0)$, the result is logically going to be zero at the terminal nodes.

At the intermediary nodes, we will chose the highest value between investment at that moment t or postponing the possibility of investing later.

$$\max(A(T-t,S_t)-I, e^{-r\Delta t}(p_u W^+ + p_d W^-) \quad (22)$$

Where W^+ and W^- are the values at the following nodes:

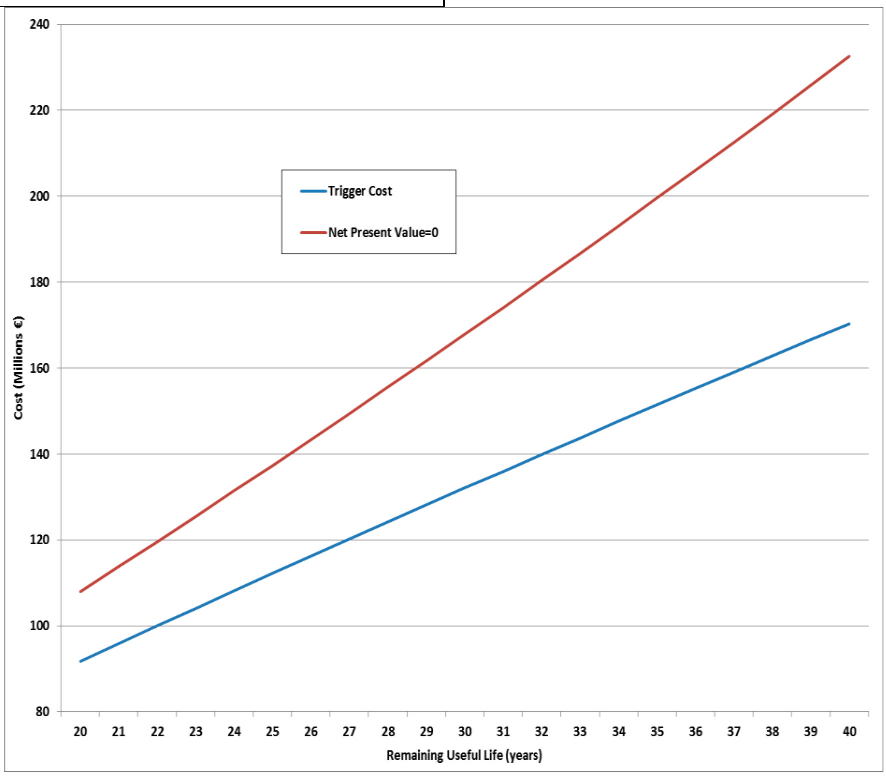
At the initial moment, we have the value:

$$\max(A(T,S_t)-I, e^{-r\Delta t}(p_u W^+ + p_d W^-)$$

Now we can ask: given $S_0 = 7.99$, what is the threshold investment cost I^* below which it is optimal to invest immediately? This will be indeed the best course of action when the NPV surpasses the continuation value. Note, though, that both parties to the comparison depend on I. This value I^* is going to depend on the remaining life of plant T.
The results of the trigger price I* and the NPV according to the remaining life are set out in Table 12 and Figure 8.

Table 12

Remaining Life	I*	NPV=0	Remaining Life	I*	NPV=0
20	91.64	107.97	31	136.00	174.09
21	95.80	113.76	32	139.90	180.38
22	99.94	119.59	33	143.77	186.72
23	104.05	125.47	34	147.62	193.11
24	108.13	131.39	35	151.45	199.54
25	112.19	137.35	36	155.26	206.03
26	116.22	143.36	37	159.05	212.58
27	120.22	149.42	38	162.83	219.17
28	124.20	155.51	39	166.59	225.82
29	128.16	161.66	40	170.33	232.52
30	132.09	167.85			



As can be observed, when the remaining life is shorter, a lower cost I* is required to make the investment and when the remaining life is greater, there are greater differences between the cost which leads to a NPV=0 and the trigger price I*.

a) The figure that we have is: cost of EUR 140 million.
Six kilns were built for the wet process at Podilsky (Ukraine) in 1970. The capacity was estimated to be 3 million tons per year of cement functioning 325 days.
The new kiln for the dry process has a capacity of 7,000 tonnes of clinker per day equivalent to 2.3 million tons of clinker per year and the production capacity is 2.6 million tons of cement per year.
The calculations that we are performing is per ton of clinker. We are also going to assume that the useful life of the plant is going to be 25 years.
Then, 140 million € / 25 = 5.6 million € / year.
5.6 million €/year / 2.3 million tn clinker / year = 2.43 € / tn of clinker.
Then the cost of changing from wet to dry is 2.43 €/tn of clinker.
Source: Joint Implementation Project Design "Switching from wet to dry process at Podilsky Cement, Ukraine" PDD version 2.1, dated 2 February 2007
b) The cost of cement plants is usually over €150 M per million tons of annual capacity, with correspondingly high costs for modifications. The cost of a new cement plant is equivalent to around 3 years of turnover.
Source: Cembureau 2014

5 Conclusions

The cement plant is the second sector with the greatest impact on CO_2 anthropogenic emissions into the atmosphere and the calcination process contributes to it. In this regard, technological improvements significantly contribute to lowering those emissions and also significantly impact on the profitability of the cements plants due to lower fuel costs and the corresponding emission allowances. The use of CCS has been proposed, but it has so far not been significantly implemented in the case of industrial facilities.

The fuel mix used for this type of plants in clinker production has recently evolved towards greater use of alternative and biomass fuels, which has impacted the price of the mix given that both the alternative and the biomass fuels are usually lower in price than the traditional fossil fuel, as is the case of petcoke. Another impact of this mix has been the need for fewer emission allowances as the result of the use of biomass fuels considered to be climate-neutral, which is equivalent to the lack of emission penalties for this fuel.

The cement plant faces both risk and profitability challenges. The improved profitability comes from the mix of fuels and of the technology used. The dry process described in this paper is thus much more efficient than the wet process, given that it uses less fuel and also emits less.

The risks of the cement plant are the consequence of the uncertainty regarding the prices of the fuel and of the emission allowances. In particular, they are subject to the uncertainty of future climate policy that could affect the amount of emission allowances available on the markets and consequently their price. But they are also subject to the future uncertainly of the amount of allowance that they can receive for free.

This paper presents a cost model for clinker production based on the emission allowance price, fuel price and the fuel mix used in the production. It is a risk assessment optimisation and control model under uncertainty.

The paper focuses on the effects of uncertainty on the prices of the CO2 emission allowance prices. This model is applied both to a wet process and to a dry process for a fuel mix. The paper shows how to calculate the risks using the Value at Risk (VaR) and preferably the Expected Shortfall (ES) by means of the Montecarlo simulation using parameters obtained by calibrating the model using market prices. The results show the greater risk and lower return in the wet process compared to the dry one. The risks are also shown to grow more sharply in the wet process when there is the possibility of changes in the general climate policy that leads to jumps in the allowance prices and/or when there is the likelihood of changes in the allowances allocated for free to the cement plants.

Finally, a Real Options exercise is performed, by calculating the trigger price of the investment cost I* under which a wet plant would be retrofitted to a dry plant. This value is notably under the one for a Net Present Value equal to zero, given that a lower cost is needed to outstrip the value of waiting option, which explains that investment are sometimes not performed under uncertainty even though they have a positive Net Present Value.

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Innovation Process in the Brazilian Electric Sector

Nivalde de Castro[1], João Martins[2], Caetano C.R.Penna[3], Cristóvão Alves[4], Lucca Zamboni[5], Mauricio Moszkowicz[6]

[1]GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil, nivalde.castro@gmail.com
[2]EDP Brasil , Rua Gomes de Carvalho1996, São Paulo, Brazil, joao.martins@edpbr.com.br.
[3]GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil, caetano.penna@gmail.com
[4]GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil, cristovao@gesel.ie.ufrj.br
[5]EDP Brasil , Rua Gomes de Carvalho1996, São Paulo, Brazil, lucca.zamboni@edpbr.com.br
[6]GESEL-UFRJ, Av. Pasteur 250, Rio de Janeiro, Brazil. mauricio.m@gesel.ie.ufrj.br

KEYWORDS: Brazilian Electric Sector, Innovation, Research and Development, ANEEL R&D program, Sectorial System of Innovation

ABSTRACT

The electrical sector is in the eve of profound modifications due to the market diffusion of several related technologies. Some drivers of this transition are: the increasing support from society for reducing carbon emissions; the growing speed of development and cost reduction of renewable energy generation technologies; new energy storage devices; new automation spread all over the network; a dramatic increase of the computational capacity; and new regulations related to energy usage.

Innovation will play a key role in the transition process of the electric sector, promoting changes and creating opportunities for new technology, products, system, regulation and business structures.

Since July 2000, law 9.991 established the Brazilian Electric Sector R&D Program that states that 1% of the income of the electric companies must be invested in R&D (research and development) projects, 40% of this overall budget stay under the electric company discretion (the Program is coordinated by the Brazilian electric sector regulatory agency, ANEEL). As a result, BRL 13.5 Billion (approximately equivalent to USD 3.5 Billion) were invested in 4,300 projects from the year 2000 until 2014. What were the results achieved by the Program? And how has it contributed (or not) to the ongoing transition process? To date, no systematic and comprehensive study has looked at the whole period of the Program.

This study introduces the first insights of a two-year research project that seeks to address these questions and to fill this gap. It presents an overview of the projects that have been carried out since 2000, and develops a unique methodology that will be used to evaluate the qualitative and quantitative historical benefits of the Program. The methodology considers four perspectives: electric companies, electric sector, academic sector and systems and services providers. It will also present scenarios that will be considered to improve the R&D Program and to inform related public policies and regulations that seek to stimulate Brazilian companies to invest in the electric sector innovation process, and ultimately contribute to the sector's transition.

1 INTRODUCTION

Since July 2000, law 9.991 established the Brazilian Electric Sector R&D Program, which states that 1% of the income of the electric companies must be invested in R&D projects. The aim of this work is to draw some preliminary results of this program between 2008 and 2014 as well as make introductory propositions to increase its efficiency and effectiveness. In order to do so, we will also provide a brief framework of Brazilian electric sector innovation process and its associated risks and opportunities.

Some previous research tried to measure the impacts of ANEEL R&D program (IPEA, 2008 and CGEE 2014) but for different periods. Therefore, the proposed methodology also aims to fill this gap in the literature.

It is worth highlighting that this work is part of a broader research that intends to make a deep assessment of ANEEL R&D program as well as provide regulatory alternatives based on international best practices.

In section 2 we will draw a summary of main tendencies regarding technological innovation for the electric sector. Section 3 provides a brief description of innovation process in Brazil. ANEEL R&D program is presented in detail in section 4. In section 5 we show some early results of the assessment of the program and in section 6 is presented the methodology that will be adopted in the research and development project that will be carried in the scope of the follow-up of this study. In section 7 we point out the main conclusions.

2 CHANGES IN ELECTRIC PARADIGM WORLDWIDE

World electric sector has been experiencing drastic changes. Environmental pressures and security of energy supply have triggered most of these fast transformations. Some aspects, such as, generated distribution, new technologies of energy generation, smart grids, technologies for efficient energy consumption, transport technologies, markedly the introduction of electric vehicles are bound to increase the complexity of the electric sector.

Technological improvements in the productive process and the increasing performance of distributed generation sources, associated to new technologies to store energy create conditions to a more decentralized generation segment, impacting heavily the traditional business.

Innovation plays a main role in the new technological paradigm that emerges, creating opportunities for several segments of the economy and establishing conditions to enhance and consolidate an Innovation Sectorial System, in order to accelerate and articulate the sectorial development agenda.

Besides distributed generation, the electric sector in the future will also face several new technologies of illumination, cooling, heating and electric cars. The development of microgrids, virtual plants aiming to approximate the energy generation and the point of consumption, and smart systems to carry and store energy will also contribute to a more decentralized sector. There is also a tendency of large-scale diffusion of sensing, controlling and communication devices, where individuals will possess equipment with high processing capacity, improving the observability within the sector. Such developments will provide important contribution to enhance performance and reduce costs.

Several authors observed this tendency and formulated analogies to explain the evolution of electric sector. The most traditional view compares the development of electric sector to what happened in the informatics industry in the 70's and 80's. The development of microcomputers that started to compete with centralized computers culminated in a destructive creation in the sector. In the electric sector, such structural changes may take a longer time to occur, given the horizon of investments and the amount required. It is reasonable to estimate that a long period of coexistence will remain until new high tech devices and machinery replace the technologies of the past. In allusion to the telecommunication sector, and the fast development of mobile phones and smart phones, it is important to call attention to the fact that distributed generation can origin new business models that could redefine the sector, mostly in distribution segment.

In this new configuration of the electric sector driven by key innovations, it is expected that consumers will have a more proactive role regarding energy generation and consumption (Prosumers). The perspective is that in following years or decades, the electric sector will develop, but the results are still unpredictable. A large number of researches on the theme has been emerging, which might also generate opportunities for innovation in the sector.

3 THE INNOVATION DYNAMICS IN BRAZILIAN ELECTRIC SECTOR

In face of the technological innovations that are likely to take place in the world scenario over the following years or decades, we will try to describe the tendencies for Brazilian electric sector as well as the risks and opportunities associated to such tendencies.

It is estimated that around 75% of Brazilian electricity is generated by renewable sources, mostly hydropower. As a result, Brazil has one of the world cleanest energy matrices. The main hydro resources are localized in Amazon region, highly sensitive in terms of socio-environmental impacts and geographically distant from high consumption areas. This fact tends to increase transmission costs, since lengthy transmission lines will be required to connect these plants to the centralized system.

Brazil presents comparative advantages regarding non-conventional renewable energy sources given climate, natural conditions and economic activities. Most of this potential comes from the abundance of winds and solar irradiation during the whole year. Biomass from sugar cane and forestry activities can also be largely exploited.

Wind energy has been increasingly introduced in the system. It is expected that this source will be responsible for 11.6% of generation capacity in 2024, which represents an accumulated growth of 213%. The main challenges associated to wind expansion currently derive from its intermittence and the necessity to readapt the transmission system to meet the decentralized aspect of this technology.

The development of solar energy will occur through solar auctions and distributed generation. Regarding distributed generation (DG), the high capital cost, associated with low regulatory incentives (net metering scheme with no commercial transactions) create obstacles to the dissemination of DG systems in Brazil. On the other hand the high end user tariff has already created the grid parity conditions. The main issues remain in the financial mechanism to decrease the end user capital investment. It is expected a high diffusion of solar energy in Brazil in the out coming years.

Biomass has been increasingly applied in industrial self-production of energy and cogeneration, and technological innovation must play an essential role to intensify the use of this source.

In the transmission area the ten years Brazilian plan (PDE 2024) presents an increase of the transmission capacity of 60% compared to the current capacity. Due to distance between the power plant sites and the energy consumption centers it is expected the implementation of several large voltage AC and DC lines in Brazil.

In the Distribution segment, the main driver will be the implementation of smart grids in several companies to improve the quality of its services and reduce the non-technical losses.

In Brazil, equipment suppliers play an important role in the innovation process since they are traditionally the main drivers of new technologies in the electrical sector. Such suppliers are usually transnational companies with large participation in Brazilian economy, such as GE, Siemens, ABB, Areva and Alstom. Therefore, we can conclude that innovation process in Brazilian electric sector is strongly dependent on large suppliers.

According to Pavitt (1984), the prominence of global players coordinating the innovative process derives from the assets specificities of the economic sector. Such specificities becomes clear when we observe that after the settlement of generation, transmission, and distribution infrastructure, most of the innovation comes from equipment upgrading, which makes possible a constant gain of productivity.

Suppliers, typically large international companies, become responsible for modernization of this equipment, and they take advantage from elevated barriers to entry. Even in the installation phase of new electric infrastructures, the intensive capital expenditure necessary requires the use of equipment in the technological frontier, in order to postpone upgrades, which increases the degree of dependence of such suppliers.

The aforementioned scenario makes necessary the development of internal mechanisms to promote innovation, in order to reduce dependence of transnational companies and to create opportunities for a more integrated national industry of capital goods. A regulatory initiative that intended to address this gap came out with the law 9.991.

4 ANEEL R&D PROGRAM

ANEEL (Brazilian Electric Sector Regulatory Agency) Research and Development program is important not only as an initiative to reduce Brazilian dependence of global suppliers in the innovation process but also to qualify human resources and to diffuse knowledge.

Decree 2.335/97 gave ANEEL responsibility for promoting research and technological development in electric sector. The regulatory apparatus established by Law 9.991/2000 required that electric sector companies should allocate 1% of their net operating income (NOI) to programs aiming to promote innovation in the sector. Forty percent of the resources is regulated by ANEEL and managed by the companies themselves. Forty percent is directed to the Ministry of Science, Technology and Innovation and the remaining 20% goes to the Ministry of Mines and Energy. Some of the R&D areas that ANEEL suggests are energy efficiency, renewable sources, environment, quality and reliability, planning and operation of electrical systems, measurement and billing, transmission of data by electric grids, new materials and components and strategic research.

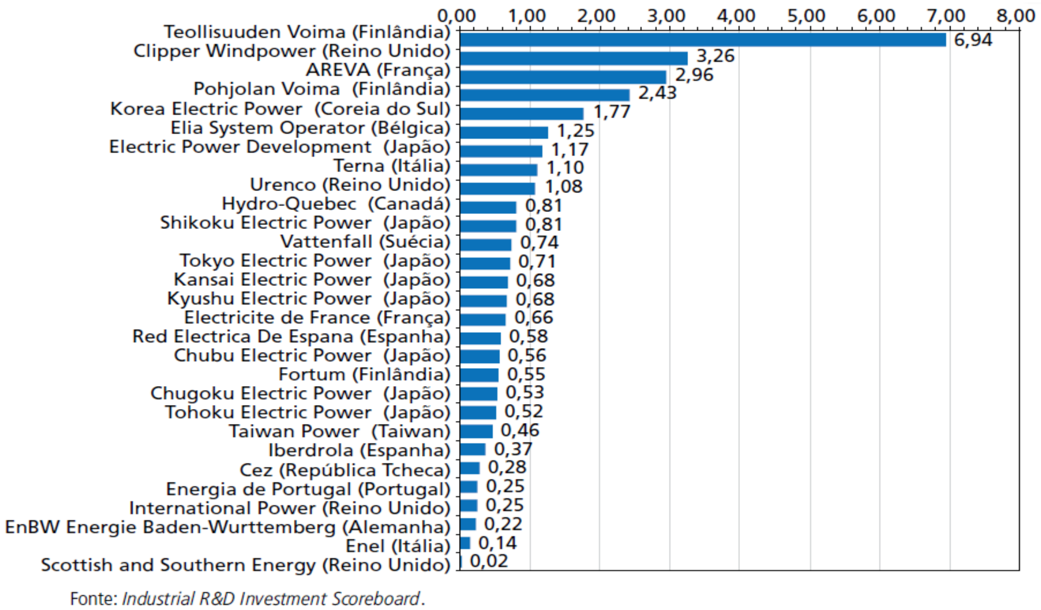
Between 2000 and 2007, the program allocated approximately BRL 3.5 Billion (USD 885 Million) in around 2,400 R&D projects. The main areas of investment in R&D during this period were strategic research (25%), energy distribution (21%) and energy generation (14%).

Given that the program is being conducted for 15 years, the main question that arises is "How to create an environment favorable to increase the efficiency and effectiveness of the R&D projects in order to promote innovation in national electric sector?" After 2008, several improvements were introduced in ANEEL R&D program in order to enhance efficiency and efficacy of the projects. The main change introduced was that the investments in R&D projects started to be recognized and approved only after the assessment of the projects and verification of expenses. The effects of such modifications will be deeply studied in the scope of a R&D project with the methodology of section 6.

5 PRELIMINARY RESULTS AND ANALYSIS FOR THE 2008-2014 CYCLE

The current situation of investments in research and development in Brazilian electric sector is well summarized by the Industrial R&D Investment Scoreboard, which ranks several electricity companies according to the percentage of NOI invested in R&D. As you can see below:

Figure 1 - Investment in R&D as percentage of NOI



Source: Industrial R&D Investment Scoreboard

In a straightforward and simple way, if we assume that all electricity companies covered by ANEEL R&D Program invest the mandatory proportion of 0.4% of its NOI in R&D activities, they all would be ranked at 23th position in average. The main proposition of ANEEL R&D program is to make electricity companies increase their investments in R&D projects in a more effective way.

Based on a report from US Energy Department, which presents the amount of investments in R&D by area from 1961-2008, we have the following results: in the period reported, USD 172 Billion was invested in R&D programs. The focus of these investments were: nuclear energy (36%), basic research and fossil sources (34%), renewable energy and energetic efficiency, that together add up 36% of total investments.

In Brazil, the particularities of the system imposed other high priority themes. Based on ANEEL public information, we can see below the amount invested in each issue:

Table 1: Quantity and value of investments in R&D projects under ANEEL regulation, by area 2008 – 2014

Year	2008 – 2011		2012		2013		2014		Total	
Issues	Quantity	Total (Million USD)	Quantity	Total (Million USD)	Quantity	Total (Million USD)	Quantity	Total (Million USD)	Quantity	Total (Million USD)
Alternative sources	70	83	40	135	11	23	17	30	138	271
Supervision and controlling	141	87	44	27	15	9	15	11	215	133
Operation	77	49	32	16	12	9	16	10	137	83
Environment	51	28	29	24	10	10	19	9	109	71
Planning	56	28	20	15	4	8	14	13	94	64
Energy quality	58	43	17	9	5	2	10	4	90	58
Measurement and billing	62	32	14	9	6	3	14	7	96	52
River basin management	18	18	14	24	4	2	5	2	41	46
Security	48	24	12	5	8	6	9	7	77	42
Energy efficiency	49	23	16	9	6	6	5	5	76	41
Thermal power	17	5	4	3	3	2	12	16	36	26
Others	79	62	13	13	14	22	20	59	126	156

Source: ANEEL, 2015

From table 1 we highlight the following points:

- There is high incidence of projects in areas such as alternative energy sources. This is in accordance with international tendency of research for new energy sources;

- Electricity companies made high investments in alternative sources. This fact can be explained by ANEEL calls for projects in strategic areas: solar energy, biomass and wind energy;

- There is an evident focus on projects associated to management, operation and maintenance of companies. Such projects are related to current needs that companies have in terms of improving management and the performance of its assets;

- The small amount of projects associated to energetic efficiency and thermal power calls attention to the necessity of better understanding of the strategic role that such themes have;

The analysis of public data shows that most of projects are developed individually by each company without any form of interaction with potential beneficiaries within the sector. This fact shows the need of coordination and cooperation. It clearly affects the learning process and the development of the sector as a whole. The large number of companies that are required to develop R&D projects makes this problem even more critical.

In the publicly available ANEEL's database it can be retrieved an indication of each project in the innovation chain. Table 2 below summarizes this information for projects developed from 2008 to 2014.

Table 2: Quantity and cost of projects according to their stage in the innovation chain

Stage in innovation chain	Quantity	Total (Million USD)	% of total value
Basic research	72	31	3,0
Applied research	682	553	53,0
Experimental project	368	384	36,7
Head of series	86	54	5,2
First batch	26	22	2,1
Market insertion	1	0	0,0
Total	**1235**	**1044**	**100**

Source: ANEEL, 2015

Differently from Frascati Manual that divides R&D activities into three categories, ANEEL expanded this number to six. They are: basic research, applied research, experimental project, head of series, first batch and market insertion.

We see from table 2 that 97% of total cost of projects is in some intermediary phase of the innovation chain. Some hypothesis can be raised from these results:

- Electricity companies can benefit directly from projects at initial stages of the innovation chain because they will be customized to its need;
- The concentration of projects at intermediary stages reduces the risk of losses in case ANEEL does not recognize part of the R&D investments made;
- Electric companies are not prepared to manage and develop basic research because such activities requires high skills and present several risks;
- Electric sector companies are not prepared and does not have commercial structure to insert their products in the market. As a result, they continue to depend strongly on suppliers and other agents.

The framework we presented above makes clear that exists a gap in the innovation cycle, since the great majority of projects were not successful in terms of introducing perceived innovation in the electric sector. Perceived innovation is the one that the entire electric sector can take advantage of.

In 2008, IPEA (Applied Economics Research Institute) launched a study in which they identified the degree of engagement of companies in the program. Their participation in most cases was limited to point out problems and check the results of projects developed by partners. Science and Technology Institutions present a closer participation in these projects.

A very important outcome of this study was the low participation of major suppliers of the sector, which also affects adversely the performance of the program. The analysis that IPEA conducted demonstrated a very low engagement of traditional suppliers in the projects assessed. It is necessary to revisit this topic through a deeper analysis for the period from 2008 to 2015 in order to suggest alternatives to engage suppliers during the project. Such initiatives would increase significantly the chances that the R&D projects generate perceived innovation for electricity companies.

The great number of projects developed and the great amount of money allocated demonstrate the success of the program. Nevertheless, there is still a need to create an environment that stimulates the innovation process in order to promote the insertion of such projects in the market.

From the analysis provided above, we can draw some initial remarks:

- A large share of the projects impact uniquely the energy companies involved directly in the R&D project;
- The majority of projects are in an intermediary stage in the innovation chain;
- An important alternative to promote evolution of R&D projects in the innovation chain is the possibility of articulation with public and private promotion agencies in order to use the resources mobilized by ANEEL R&D program that are managed by the Ministry of Science, Technology and Innovation;
- There is a necessity to create mechanisms to stimulate the participation of national and international suppliers in the R&D projects;
- Academic institutions with robust technologic capacitation must articulate and propose projects consistent with emerging and disruptive technological areas such as: energy storing, nanotechnology, chemistry, new fuels, etc. Such projects require massive investments that must be made in association with companies in the sector.

5. PROPOSED STUDY

The proposed study has the scope of increasing the ANEEL R&D Program and comprehends the following points:

1 – Assessment of economic and technological impacts of the Program on Brazilian electric sector (including consumers), including trends and alternatives in terms of technology, such as main technological focus, development stages, existent and potential market. The work comprehends interviews with key agents of the electric sector to assess: obstacles in formulating new projects, strategies to mitigate investments risks, strategic partnership with academic and industrial sector, expected and effective results generated by the program, barriers to commercialize technologies.

2 – Assessment of qualitative and quantitative impacts of the Program on Brazilian electric sector: Interviews with R&D managers and services and equipment providers to assess alignment of the R&D projects with the company strategic policy, capacity to disseminate an innovation culture inside the companies, establishment of new metrics to monitor and evaluate the R&D projects.

3 – Assessment of the impacts of the R&D projects in academic sector including: identification of the main academic centers, research areas and specialists involved in the projects; scientific production (patents, papers, masters and doctoral dissertations and others); investments in laboratory facilities and acquisition of equipment; training initiatives for human resources of companies. The methodology includes several technical meetings and interviews with selected professionals in order to assess qualified information, regarding: Impacts of the R&D projects in terms of raising funds for research infrastructure in the universities; Main obstacles regarding projects execution.

4 – Assessment of impacts of the projects on supply of new goods and services: evaluation of the participation of services and equipment providers in R&D projects, in order to examine the impacts of the projects on supply of new equipment and services. We will also provide an assessment of the main obstacles and propose measures in order to obtain a more efficient projects execution.

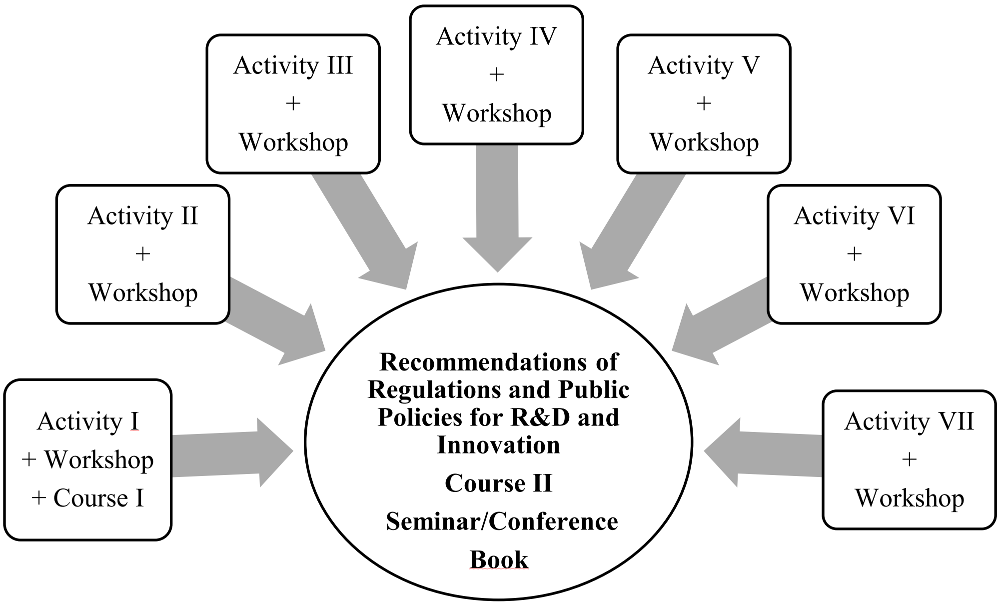
5 – Assessment of the value creation potential of the R&D program given its available resources and based on methodology of value generated by technological development modeling including the selection/prioritization of main issues and a quantitative evaluation of the potential benefits generated.

6 - Assessment of international best practices to maximize the value generated by innovation programs: This step includes a selection of successful cases. For those selected cases, it will be developed an extensive bibliographic review and interviews with local specialists in order to provide a detailed assessment of: regulation framework, funding available, electric energy technologies and product promotion using them in its installation, industrial and sectorial policies and government policies to stimulate innovation and the role of startup companies.

7 – Development of public policies and recommendations to stimulate R&D and perceived innovation in the Brazilian electric sector through regulations and laws in order to create a sectorial innovation system.

At the end of each point abovementioned, we will give a workshop to a more specialized target audience, including ANEEL's technical staff. We will also provide seminars to a larger number of stakeholders including public sector institutions such as BNDES (National Development Bank), MIDIC (Ministry of Development, Industry and Foreign Trade), MCT (Ministry of Science and Technology) and provide an international seminar at the final stage of the study. This work will also generate masters and doctoral dissertations, technical and academic papers. We aim to give courses on the Program to key agents and publish a book on the analysis conducted at the end of the study. Such activities are summarized in figure 2 below:

Figure 2 – Summary of activities



6. CONCLUSIONS

In this work, we tried to draw some preliminary result on the R&D program conducted by ANEEL and managed by electric energy companies during 2008 and 2014.

The extension of this study must develop a deep analysis in order to propose a new regulatory apparatus designed to promote the innovation dynamics in Brazilian electric sector. Such initiative is very important in face of the perspectives on a new technological paradigm that has been emerging in the electric sector and the particularities of Brazilian Electric Sector.

The proposed study will be coordinated by the Study Group of the Brazilian Electrical Sector (GESEL), sponsored by two large Brazilian energy companies (EDP and ENERGISA), with a strong involvement of several national and international academic centers, suppliers, electric companies, association and government agencies (such as: Mines and Energy, Science and Technology and Industrial Development institutions and organizations).

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