UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

MARGINAL CONTRIBUTION OF RENEWABLE ENERGY SOURCES TO THE REDUCTION OF EMISSIONS AND SECURITY OF SUPPLY

Author: **Deniz Sun**

Supervisor: **Julián Barquín Gíl**

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Official Master's Degree in the Electric Power Industry (MEPI)
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Master's Thesis Presentation Authorization

THE STUDENT:

Deniz Sun

……………………………………………………

THE SUPERVISOR

Julián Barquín Gíl

Signed: …………………… Date: 30/ 06/ 2016

Authorization of the Master's Thesis Coordinator

Dr. Luis Olmos Camacho

Signed.: …………………… Date: ……/ ……/ ……

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Abstract

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Deniz Sun

Increasing concerns in global warming, pollution and security of supply over the last decades point out the importance of renewable energy sources. They do not emit greenhouse gases or any toxic pollutants, diversify energy supply, improve fuel independency and supply adequacy, reduce system operating costs, and stimulate economic growth. Unfortunately, renewable sources are not competitive enough in current markets, where these externalities are not fully internalized in the price of energy. In this thesis, a methodology is proposed to evaluate marginal impacts of RES capacity increase on emissions, operating costs and adequacy. The methodology is implemented to the Iberian electricity market and it is applicable in European markets. The impacts are monetized separately for each pollutant, cost component and RES technology (wind and solar photovoltaic power systems) for the year 2015. First, marginal units are identified in every hour and then associated emission displacement and operating costs savings are computed. For adequacy savings, a heuristic approach developed. Results show the comparative advantage of wind over solar photovoltaic power systems as well as cost savings by 1 MW of RES capacity increase. The study also compares the findings against estimated technology costs. This proposed methodology provides a transparent tool that might be used for analyzing RES support schemes and for future policy design.

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1. Introduction

Oil crises at 1970 and the volatile nature of the price of oil and its derivatives had triggered the concerns on imported fuel dependency, in other words, security of supply. Apart from that, Chernobyl and Fukushima nuclear accidents weakened the support on nuclear energy as a clean energy source, and increased social pressure on parliaments to promote alternative electricity generation technologies. Moreover, risen greenhouse gas (GHG) concentration over the last years dragged global warming to critical levels. Kyoto conference in 1996 and the most recent and first universal legally binding global climate deal adopted in December 2015 in Paris clearly show the importance of global actions to control emission levels. Fossil-fuel burning, to blame for global warming, is also responsible from local level health and environmental problems by emitting toxic pollutant in air. As a result of these recent events pointing out the environmental problems and security of supply, promoting renewable energy sources (RES) and controlling emissions have become a topical issue on countries' agenda.

RES offer diverse economic and social benefits to the system: They (1) maintain a healthier environment as they do not emit pollutants; (2) improve security of supply by diversifying energy supply, improving fuel independency, reducing country's exposure to expected future fossil prices, and improving available generation capacity of conventional generators; (3) reduce system operating costs and lower wholesale electricity prices; (4) stimulate economic growth; (5) promote technological innovation; and (6) create jobs. These advantages are pushing forward the investments on RES.

Investments on renewable energy sources (RES) are globally growing apace to nearly six times its 2004 total, reached to $329 billion. Although the investments show a lower increase in 2015, at $58.5 billion in Europe, they were doubled over the past eleven years (Frankfurt School-UNEP Centre/BNEF, 2016). Throughout the years, these ongoing investments boosted the share of renewable energy generators in the power systems and gave a crucial role in energy generation. As one of the leader country on RES development, Spain for instance supplied 37.4% of total electricity by RES in 2015 with a breakdown of 19.1% of wind, 3.1% solar photovoltaic (solar PV) and 2.1% solar thermal. Total electricity supplied by RES rose up by approximately from 10% in 2006 to 26%

in 2015. Also, remarkable improving cost-competitiveness of wind and especially of solar power at recent years signifies the potential capacity rise in the following years.

In European Union (EU), in line with the recent trends on controlling environmental damages and improving security of supply, the binding target by 2020 is reaching 20% energy consumption from renewable energy and reducing of CO_2 emissions by 20% from 1990 levels. The main instrument has been implemented to promote RES investment is National Renewable Energy Support Schemes at which member countries put in place a variety of support schemes independently, i.e. production-based, capacity-based incentives, separately or as a mixed strategy. In principle, these schemes are designed to bring RES to their desired economically and socially efficient levels, that is, by reflecting external benefits together with costs. In addition to the RES support schemes, the mechanisms to control emissions of toxic pollutants and CO_2 are the Industrial Emissions Directive (IED or Directive 2010/75/EU) and EU Emissions Trading System (EU ETS), respectively. While the directive sets limits for each pollutant, EU ETS aims to internalize the external cost of CO_2 within the market mechanism.

On the wholesale markets of energy, in competitive markets, the price which is set by the intersection of demand and production bids is the variable cost of the marginal unit. However, this price does not reflect the real effect of each activity on the prices. In other words, operating cost or electricity market prices do not include the external effects of RES such as avoided emissions, avoided operating costs and improved security of supply. In fact, the markets which do not internalize generation externalities cannot operate efficiently (Longo, et al., 2006). That is why, policy interventions, i.e. EU instruments, behind renewable energy have a key role on reaching the desired level of RES investment. This raises importance of the incentives, their implementation and most importantly, their rationalization. As one of the mechanisms, production-based incentives are expected to reflect the total cost of investing in RES, including economic and environmental benefits and costs.

From short to long term benefits of RES on the grid by replacing the marginal generating units are (1) reducing the operating cost; (2) reducing CO_2, SO_2, NO_X, and particulates emissions, (3) improving system reliability by increasing available generation capacity, at marginal electricity generation units. Quantifying these benefits of incremental RES investment will help to understand and rationalize the regulatory policies and will be beneficial for future policy design as well as commercial applications and guidance of commercial decision making. In fact, studying the effect of incremental capacity increase of renewable energy may provide relevant information as investments on both traditional and new renewable energy generation units rise RES capacity considerably lower compared to the conventional generators.

The objective of this thesis is to develop a transparent and simplified methodology to examine the effect of an incremental increase in renewable energy in terms of costs and external benefits. The broadly applicable methodology will measure and monetize the effect of an incremental capacity increase in RES to avoided emissions, operating costs and security of supply in terms of adequacy using public data. While doing so, current infrastructure and framework is taken as the basis of the analysis. Developed methodology will be implemented to Iberian Peninsula and it will be adaptable to similar electric power systems. Also, robustness of the developed methodology is investigated.

The organization of the thesis is as follows. Section 2 presents similar studies in the literature. Section 3 describes the European instruments to promote RES investment and control emissions and continues with Spanish and Portugal framework. Section 4 gives a short review on power system of Iberian Peninsula. Section 5 presents the methodology developed to measure the marginal effect of RES to operating costs, emissions, and security of supply in terms of adequacy. Section 6 describes the data used to implement the methodology to the Iberian Peninsula and continues by providing the results and analysis. Finally, Section 7 concludes the thesis.

2. Literature Review

Renewable energy shares in the power systems are far from the desired efficient levels that helps the countries to reach global and local environmental targets and provide higher level of security of supply. By identifying the right cost and benefits of RES investments to the system, correct actions can be decided, right amount of subsidies can be set, and RES growth can be lead efficiently. Obviously, this need leads to a growing literature on impacts, impact valuations and their comparison with the incentives, and cost-benefit analysis of RES investment to the power systems.

Cullen (2013) quantifies avoided emissions by incremental wind power generation. This paper develops a sophisticated methodology to capture the relationship between total wind and each conventional power generators' output in every 15 minutes assuming that wind generation has an impact on each generator in some level. The relationship between wind generation and each conventional generator output is demonstrated by a simple linear function with quadratic expansion of each control variable to allow nonlinearities in the underlying model. The control variables are divided into two as contemporaneous and lagged in order to capture operating conditions of the generator and their dynamics. After constructing the estimates of conventional power plants output reduction by marginal increase in wind power, the writer uses average emission rates for each plant calculated by yearly emissions of plants. Finally, he monetizes the damage of a ton of CO_2 emission by the social cost of carbon set by The Interagency Working Group on Social Cost of Carbon and gets help from literature to monetize the damage of SO_2 and NO_X emissions.

However, the main assumption stating that even the base units such as nuclear technologies change their output level contradicts with the real production pattern of the base units (excluding very high wind production moments). Cullen (2013) examines the main harmful pollutants, CO_2, SO_2 and NO_X but excludes another severely harmful pollutant, particulates. Also, the only benefit of wind deployment considered in the study is emission savings; that is, other benefits are out of focus so that cost subsidies of wind are comparable only with emission values, $/MWh of wind power. All in all, although a sophisticated and robust methodology which evaluates the marginal impacts of CO_2 and SO_2 is presented, the analysis stays in one benefit for one of the renewable energy sources while providing a comparison between wind subsidies and emission costs.

Kaffine et al. (2013) follow the same but a more advanced econometric method stating that marginal emissions cannot be estimated by the multiplication of their average values with the power output of conventional generators. Using the hourly real plant specific CO_2, SO_2 and NO_X emissions data and wind generation in Texas, they identify the marginal change in emissions due to a change in wind production. Similar to Cullen (2013), their regression includes the control variables to control correlation between them, wind generation and hourly emissions, and consider Texas disconnected from other regions so that imports and exports are not affected by a change in wind production. However, their study is also limited to wind technology and three main pollutants in addition to monetizing the damage cost for only CO_2.

Following the same methodology with Kaffine et al. (2013) and Cullen (2013), Novan (2015) formulates the relationship between hourly CO_2, SO_2, NO_X emissions and wind, solar PV generation but focuses on the quantification of the heterogeneity in the pollution avoided by marginal increases in renewable generation. Due to insufficient data, marginal emission rate is calculated for wind generation and the same estimates are used for solar PV, assuming that solar PV generation has the same impact on emission as wind generation. So, hourly avoided emissions by addition of marginal renewable capacity and finally average avoided emission are found. This study has slight differences compared to the previous paper discussed. The author includes solar PV to his calculations and uses the predictions of Texas from Banzhaf and Chupp (2012) for monetizing the impact of SO_2 and NO_X emissions. Still, impact and emission rates of particulates are not examined.

While Graff Zivin et al. (2014) similarly estimate marginal emissions but with demand by region and hour for only CO_2, Siler-Evans et al. (2012) regress the hourly change in emissions CO_2, SO_2 and NO_X (separately) against the hourly change in fossil fuel-fired power generation. By this way, Siler-Evans et al. (2012) reach marginal emissions rate without including renewable energy generation into their formulation.

All these previous studies follow the same methodology with some differences, yet they lack on examining other benefits of a marginal capacity increase of RES, also the costs. Marginal impacts of RES investments are significant measures of subsidy rationalization and it is essential to include all the benefits and costs to the computations. Moreover, only one of the previous studies include solar PV to their analysis while the others restrict their studies on wind power.

In line with the focus of this thesis, Callaway, Fowlie and McCormick (2015) extend these analyses by including operating cost and capacity value generated to the avoided emissions. They develop a simplified and transparent but data intensive methodology in order to estimate marginal external emissions-related benefits of solar PV and wind power by a marginal increase in their capacity. They assume that only fossil fuel production responds to an increase in renewable output or energy efficiency. While capacity value of RES is computed by capacity prices, 1 MW of capacity increase and capacity factors, they use locational marginal prices as a proxy of hourly operating cost. In order to calculate marginal emission rate for CO_2, first, they cluster days for each region and season which show the similar generation patterns. Then, they reach hourly emission related to fossil fuel-fired electricity generation. After monetizing the effect of avoided emission savings of CO_2 with social cost of carbon, net cost of incremental RES investment is computed as difference between benefits and the levelized cost of electricity for wind and solar PV so that the results can be comparable with dollars per MWh subsidies.

Although growing literature which evaluates benefits and costs of incremental RES capacity increase has its examples implemented to the US power systems, no similar study has been done for European power systems. In fact, hourly emission data unavailability of fossil fuel-fired power plants in Europe does not allow to implement the methodologies used in previously discussed articles. Differently, at the study of Marcantonini and Valero (2015), a deterministic unit commitment model is used to calculate carbon price savings, fuel cost savings and capacity value in Italy between the years 2008-2011. Capacity value in this study corresponds to the fixed cost of building and maintaining conventional capacity. By their model, they compare no energy generated by wind and solar scenarios separately with the historical generation data. Similarly, Holttinen (2004) studies the impact of wind power on the Nordic power system by an hourly unit commitment model at the doctor’s thesis and provides a detailed analysis on the short and long term effects of wind power capacity. The defined impacts are on operating reserves, replaced energy and avoided CO_2 emissions by using average emission rates, transmission and capacity credit.

There are various cost-benefit analysis in the literature evaluating the effect of projected RES growth to the national power systems. For instance, Denny and O'Malley (2007) use an economic dispatch model with multiple scenarios to reflect expected RES growth at the years 2010, 2015 and 2020 for Ireland, Frias et al. (2010) evaluate the impacts of RES growth for the year 2020 for 20% and 30% of RES share in total energy generation in Spain. Some of the costs linked to RES capacity increase in these papers are operation and maintenance costs, operational reserve costs, CO_2 emission cost, annuity of investment in RES, and support payments for actual RES units. Moreover, in each study, their evaluations are based on several impacts. Ortega et al. (2013) examine the benefits of avoided CO_2 emissions and fossil fuel imports of RES deployment in the years 2002-2011 in Spain, Gelabert et al. (2011) analyze the impact of an increase in RES generation to the electricity prices in Spain and Tourkolias and Mirasgedis (2011) quantify and monetize the effect of RES on employment as €/MWh of RES electricity generation in Greece. Another study conducted by Burgos-Payan et al. (2013) simply gathers the effects of RES integration cost to the country's GDP, new job creation, avoided emissions, avoided health costs related to harmful pollutants, and also evaluates the drop on wholesale price for Spain.

Although these analyses clearly define the benefits and costs of RES deployment and some quantify these effects in European countries, they do not evaluate marginal effects. However, in order to set a sensible scheme for RES support, defining their marginal effects is also essential. By evaluating the net marginal effect including the costs and benefits of RES, their right price per MWh of RES generation which allows to set the right amount of subsidies can be computed. Cullen (2013), Kaffine et al. (2013), Novan (2015), Siler-Evans et al. (2012), Graff Zivin et al. (2014), Callaway, Fowlie and McCormick (2015) study these marginal effects for the some of the US power systems by applying similar methodologies. The purpose of this work is therefore to extend and replicate these methodologies for European system in the case of hourly emission data unavailability.

3. Renewable Energy Support Mechanisms

3.1. Overview

Modern technology is still not able to provide RES at competitive levels, meaning that power markets are still not able to provide the required quantities of energy delivered by RES in the EU. To put it simple, there is a big chance that the cost of the investments will not be compensated over the life of the renewable unit, if the compensation comes only from the market price, as a result of the pure competition. Therefore, to support the goals of 2020 and the following 2030 and 2050 targets, European countries have to promote them in some way to overcome such a market failure and be able to maintain the investments influx into the industry. Since the current market structure has not yet been internalizing the external effects of the RES into operating costs, investors will need to be additionally rewarded in some way for deploying a renewable generation unit and their investments will be guaranteed (or will have a much more probability) of paying off in the future.

However, this contains a big risk of worsening market efficiency and end with distortions and disproportions of benefits leading to eventually higher costs for European industries and households. That is why, designing the right policy is a delicate issue. The appropriate support scheme is not straightforward, and as expected, the history records lots of errors and learning from those which also leads to frequent changes in the structure. In fact, the important aspect of the support schemes design is its flexibility. Support scheme should be both: changeling enough to take into account alterations in the development of technologies and costs, and stable enough to guarantee the low risk and low cost of capital.

All in all, the main principles behind well-designed renewable support scheme are: long-term; flexible and changeling, yet predictable and transparent which should not be constant, but just promoting RES in their desired efficient levels of capacity share and operation. In order to do that, various mechanisms have been implemented in the EU: feed-in tariffs (FIT), feed-in premiums (FIP), contracts for differences (CfD), quota obligations, tax exemptions, tenders, and investment aid, which vary by investors being vulnerable to a different market price risk and having different expectations on risks. The choice of the respective support scheme also depends on the technologies being promoted, on the scale, location, historical background and other policies (European Commission, 2013).

Feed in tariff (FIT) is a certain fixed and guaranteed production-based incentive paid to a generator. Feed in tariff provides insurance to the new market entrants from being exposed to a price risk. The easiness and transparency of feed in tariffs are among the reasons why the countries start to implement those, this way a lot of participants, even small households, could participate in the market. Nevertheless, the main disadvantages of FIT are the impairment of liquid and flexible markets, the growth limitation of certain technologies and installations size, as well as the complexity of calculating the adequate levels of tariff and subsequently adjusting them.

FIT can vary depending on the type of (or the presence of) adjustment. The support scheme can be planned in the way that the tariff can be definite for a predefined time period or can be adjusted gradually, thus reflecting the technology development and the costs being decreased. Depending on the growth of the technology and the amount of generators installed, support can be limited by capping. In addition to that, regulators may change the previously defined tariff structure (even retroactively) which creates regulatory risk for the investors.

Feed in premium (FIP) unlike FIT is a scheme which does not fix the constant remuneration for KWh produced. FIP is an addition per KWh incentive to the market price which renewable generators receive. This system possesses several advantages compared to other support mechanisms, main of which is an obligation of RES producers to be full-functioning market participant thus being exposed to the market price and acting effectively according to that. With this type of the support, renewable energy is allowed to be traded in multiple markets including energy exchanges and bilateral agreements. This scheme puts pressure on RES generators forcing them to participate in the market actively, and to be more efficient and to use their investments more optimally.

Different types of premiums exists which have variable market exposure effects. There are fixed and variable premiums. The latter, which are also called floating premiums, are subsequently divided by the frequency of their adjustment (hourly, monthly, yearly) and the presence of either floor or cap or both.

Quota obligations force energy suppliers to have specified quantity of energy produced from renewable sources or green certificates which are representing this quantity. This type of instruments comprise a market, where RES generators and energy suppliers can trade between themselves the certificate at prices determined by them and other market participants. In addition to quota obligations, energy sector uses tax reductions and exemptions quite extensively. Their application and implementation are significantly dependent to the economic and political course of the government and country and country's fiscal policy in particular. Unlike the previous mechanisms, auctions and tenders are not the support schemes but they are helping tools to define the remuneration used in the actual support and mostly auctions are combined with FIT or FIP schemes. This way the amount of the support is defined in a competitive manner. Lastly, aiming to compensate capital costs of RES investment, investment supports are implemented. In fact, the previously discussed tax reduction and exemptions can also be a type of investment support. These supports do not distort the market mechanism by offering grant or loan to the parties investing in RES (European Commission, 2013).

Currently support schemes are meant only at the domestic level (with an exception of Sweden-Norway joint support scheme) so that Member States have the right to choose their own policies (see FIGURE 3.1 for the switch towards FIP from FIT and quotas, and implementation of auctions in the EU). The only global target at this point is 20% by 2020 and 27% by 2030 of RES in final energy with no targets per nation.

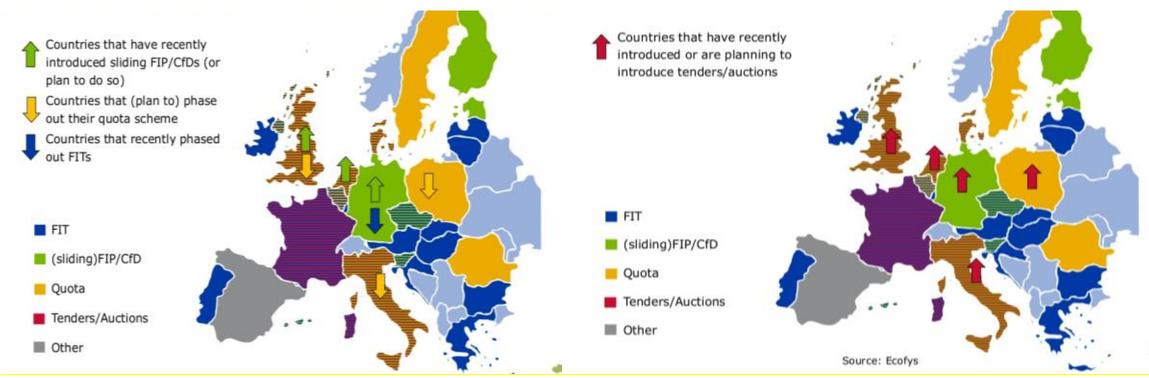

FIGURE 3.1: Switch towards FIP from FIT and quotas, and implementation of auctions in the EU. (Source: Ecofys)

3.2. RES Support Schemes in Spain

Spain is considered as one of the European leaders in terms of renewable energy support, promotion and implementation. As it has been a pioneer in RES support scheme introduction, it was one of the first to implement FIP for the wind generated energy, FIT for concentrated solar power and extra remuneration for the renewable energy generators which are able to provide the system with reactive power.

Spanish history of RES support schemes can be basically divided into two main parts: active promotion of RES with FIT and FIP before 2013 and new “specific scheme” after 2013 which is much more timid, guaranteeing “reasonable rentability” for generators.

The introduction of two support schemes - FIT and FIP - in the late 90s had a big effect on the following expansion of the green technologies in Spain, most notably on wind and solar power generation. The effect was mostly seen in 2000s, when the legislation foundation established one decade prior started to kick in, the projects started to be built and deployed, and remuneration started to take place. For example, conventional fuels were still getting almost double of the amount of support compared to RES in 2005. But already six years later, in 2011, the ratio switched drastically with RES share in the support funds to more than double compared to the one of conventional fuels.

On top of that, RES generation via FITs and FIPs was financed directly by the consumers of the energy, while conventional fuels were supported by state budget.

Eventually the period between 2005 and 2011 has shown a tremendous expenditure for FIT/FIP schemes in more than €20 billion in total (only solar and wind, not taking into account other technologies). The numbers of money spent as a part of the support schemes in 2005-2012 and in 2013 can be seen in the table below.

TABLE 3.1: FIT and FIP payments for renewable electricity, 2005-2010 (thousand EUR) (Source: CNE & CNMC)

	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Solar PV						2,650,688	2,281,528	2,613,838	2,561,335
Wind	612,785	865,815	194,819	1,155,818	1,619,203	1,964,347	1,710,865	2,049,615	1,111,713

Up until the financial crisis, Spanish RES market had proven to be extremely attractive for the investors mainly because of the support schemes it used to have (FIT and FIP). The operators of the new renewable power plants were proposed to choose between two options: FIT or FIP (not available for solar PV generators). This made most of the solar generation being supported by FIT, while FIP was predominant for the wind technologies. According to the legislation introduced in 2007 (RD 661/2007), the duration of the support and the size of the premiums and tariffs were defined considering the technology group, subgroup, age of the installation and power range. The level and duration of support depended on the technology and the size of the project. The FIPs had a cap and floor system in order to limit excessive compensations (EEA, 2014).

The main changes and the fall of the support for renewable in Spain came after the economic crisis in 2007-2008. The incapability of coping with the tariff deficit growth over the years forced to start limiting the support for RES. Finally the support scheme was redesigned in 2013 by suspending the previous FIT and FIP schemes. The actions included decreasing the operating hours to be remunerated by the regulated tariff. The availability of the support for solar PV was also cut by decreasing the amount of solar eligible for it. Administrative and bureaucratic procedures were made more difficult in order to put additional barrier and control on the implementation of the new projects. Additionally, access toll was introduced, making the generators pay for the transmission and distribution network proportional to the energy dispatched. What is more, FIP was reduced by 35% for wind plants with a capacity over 50 MW and between 5 to 45% for solar while promoting 7% tax on energy produced for all generators (Morris & Pehnt, 2015).

What came as a change of FIT and FIP support schemes is not defined as such technically. It is considered to be supplementary paybacks allowing RES technologies to be able to compete with traditional ones in the energy market. Participation in the market is a must for all the RES generators at this point, otherwise there will be no remuneration.

The amounts of these paybacks are based on a set of parameters, which are specifically calculated for a certain sample of "standard installations". Those theoretical standard installations were developed with the respective values obtained. The methodology for those calculations is somewhat not transparent and not clear. This way the RES developers will be provided with a "reasonable rentability" (defined as the average yield of the State obligations to ten years in the secondary market for the 24 months prior to the month of May of the year preceding the start of the regulatory period increased by a spread (Art. 19 RD 413/2014); which is Spanish bond + 3%), that ideally well-managed renewable plant would normally have. Taking into account the results and the performance of the RES unit, the generator will be given a certain amount that correspondents to the theoretical "standard installation" being managed appropriately would receive. In general, the new support scheme supports the operational and investment side (RES-Legal Europe, 2014)

Operational additional remuneration calculated in Euros per MWh is provided when forecasted market price (published by the Ministry) is lower than the theoretical standard operational cost, which includes fuel, maintenance, management costs, network access, land rent, security costs, insurance, carbon allowances, taxes and others (Barquin, 2014). The remuneration itself is the difference between the two numbers.

Total remuneration takes into the account standard variable cost basis so that “reasonable rentability” is obtained. Market revenues and operational additional remuneration for the standard facility obtained in the past are subsequently diminished to get the amount of current investment remuneration (if negative, it becomes zero). In this case, more efficient generation units earn more as lower production costs give them bigger return from market revenues. In case market prices are much lower or higher than forecasted market prices, some complex provisions are made (Barquin, 2014).

3.3. RES Support Schemes in Portugal

The main RES support scheme in Portugal is feed-in-tariff, which is only applicable to the existing installations. The exact amount of FIT is calculated using special formula (art. 2 DL 225/2007) and depends on the source of energy used. Decree-Law 339-C/2001 introduced the coefficient Z, which defines the remuneration method for renewable energy between several tariff levels depending on which technology is used for the production. This formula is quite complex and Z is the coefficient which reflects the particular set of resource and technology characteristics used in the facilities.

€74-75 per MWh (DL 225/2007) is the average rate for the existing wind installations. Wind plants covered by the provisions of DL 35/2013 that have an access to a Decree-Law provided alternative regime will have to pay an annual compensation to the National Electric System starting from 2013 and till 2020, amount of which is based on a reference value of installed power in MW (Art. 5 of DL 35/2013). Wind payments are being stopped when one of the two conditions reached: either 33 GWh of electricity was produced or the plant has been operating over 15 years (RES-Legal Europe, 2015).

For solar power plants: (1) €257 per MWh (DL 132-A/2010) is the average rate (indicative) for the existing solar PV installations (PV); (2) €380 per MWh (Ordinance 1057/2010) for concentrated photovoltaics (CPV) installations with a capacity up to 1 MW up to a limit of 5 MW of installed power on the national level; (3) €267-273 per MWh (DL 225/2007) for Concentrated Solar Power (CSP) installations with a capacity up to 10 MW. Yet, solar thermal payments are being stopped when one of the two conditions reached: either 21 GWh of electricity was produced or the plant has been operating over 15 years (Art. 2(c) of DL 225/2007) or when 34 GWh is reached or 20 years of operation (Art. 7 of DL 132-A/2010) for solar PV (RES-Legal Europe, 2015).

Speaking of micro and mini generators (Small Production Units (UPP)), one of the major changes was made in 2015 (DL 153/2014) as for support schemes designed for them. Old remuneration schemes will still be applicable for the installations which were built before the changes were made, but only till the end of the statutory period. Under the new regulation, the producers of electricity are offered a FIT scheme via a reverse auctioning that is capped at the reference tariff of €9.50c/kWh. Solar systems will receive 100% of this reference tariff while wind receives wind 70%. It is important to remark that wind and solar generators are eligible to FIT for up to 2.6 MWh per year (5 MWh per year for the eligible RES). Apart from these, no registration fee and simplified registration procedure with grid operators are applied for all the RES facilities with less than 1.5 kW capacity (RES-Legal Europe, 2015).

4. Iberian Electricity System

4.1. General Overview

Iberian Electricity Market (MIBEL) which forms a single power market for the Spanish and Portuguese parts of Iberian Peninsula was created in 2007. MIBEL consists of (1) a spot market managed by Spanish market operator (OMIE), (2) a futures market managed by Portuguese market operators (OMIP), (3) an ancillary services market, and (4) a bilateral contracting market (OMIE, 2015). Spot market is managed through day-ahead and intraday markets where buying and selling agents from Portugal or Spain submit their bids. Also, generators can submit their complex economic and technical conditions such as minimum average price or minimum operating hours (Vazquez, et al., 2014). That is why, instead of internalizing fixed costs related to the operations (start-up and shut-down costs, ramp-up and ramp-down limits) into their bids, selling agents mostly express these constraints in their conditions. The lowest cost bids are matched to buyers until all demand bids are covered and finally the last generator bid accepted sets the price. After that, the bids which do not satisfy their submitted complex conditions are removed from the sale offers and finally the clearing price is determined by the intersection of the matching sale offers and purchase offers (see FIGURE 4.1).

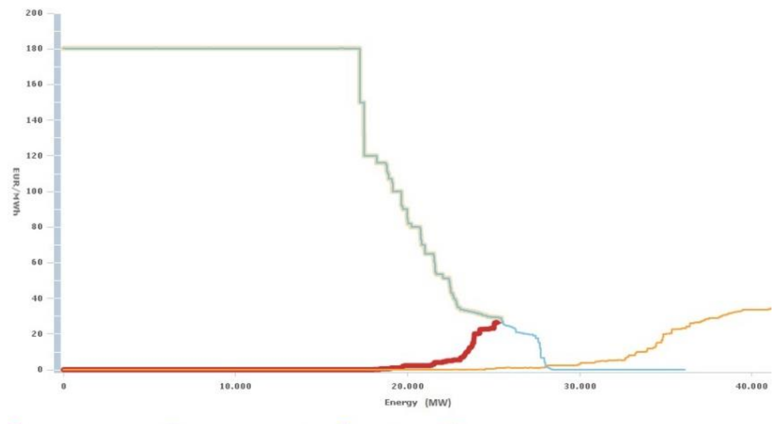

FIGURE 4.1: MIBEL daily market clearing at the hour 19, 12/07/2016. (Source: OMEL)

The day-ahead and intraday markets are non-compulsory pool-type markets. However, generators are incentivized to participate in the day-ahead pool market because of the criterion to participate in the capacity market is participating in the day-ahead market. The day-ahead market is organized in twenty four hourly based auctions that are cleared at the same time between 10:00 and 10:30 CET (Central European Time). In this market, sale offers submit up to 25 price-quantity pairs of offers. On the other hand, loads submit demand functions that indicate the maximum price at which they are willing to buy a certain amount of energy. Apart from the quantity of price pairs, selling agents can also submit their minimum income bids whenever it is relevant. Generally, the products that are traded in this market are hourly based products. In intraday market, it is possible for market participants to adjust their physical positions in either direction after the day-ahead market is cleared. The adjustment of physical position happens in a sequence of implicit intraday auctions and participants submit their bids until four hours before the real time.

With total traded energy of 259 TWh in 2015 by participation of 930 agents, Iberian spot market is considered as a liquid market. The market has five main players with 15-24% market share which leads to moderately competitive bids (OECD/IEA, 2015). In fact, the report of the Spain's National Authority for Markets and Competition (CNMC) to the European Agency for the Cooperation of Energy regulators (ACER) (2015) states that there are no complaints about anti-competitive practices in Iberian Market. Also, the report gives the example of Spanish day-ahead prices being in the range of other European market prices[1] (CNMC, 2015). While 80% of the total electricity demand is traded in day-ahead market, this rate is lower in the intraday market.

MIBEL acts as single market for 98% of the time[2] (OMIE, 2015). In case of congestion between Portugal and Spain, market splitting is applied which causes higher prices at the country with a high energy demand. In fact, after the installation of the new lines, both sided exchange capacity between Portugal and Spain have reached 3000 MW in 2015. However, Portugal has interconnection only with Spain and Spain is connected to Europe through France with an exchange capacity of 1400 MW until October 2015 and 2800 MW starting from that date (REE, 2012). Although the market is well-connected in itself, these insufficient interconnection capacities with the rest of the countries separates Iberian Peninsula as a isolated island. While single price was observed only 9% of the time in 2014 between France and Spain, doubled interconnection capacity at the end of 2015 increased this ratio to almost 15% in the year 2015. Even with an improvement in interconnections, Iberian Peninsula can still be considered disconnected from Europe.

[1] Competition can be analyzed through benchmarking prices with those of other European spot markets (CNMC, 2015).
[2] Price difference less than 1€ per MWh.

4.2. Spanish Peninsula

In 2015, electricity demand in Spanish Peninsula reached 248 TWh which is almost 2% higher than in 2014. This demand is covered by nuclear (21.7%), coal (20.3%), wind (19.1%), hydro (11.1%), cogeneration and other (10.6%), CCGT (10%), solar PV (3.1%), solar thermal technologies (2.1%), and international exchange (2.0%). After the 2008 crisis, the demand and peak demand along with that have followed a downward trend. Yet, in 2015, they both showed an increase and peak demand reached 40.324 MW in February in Spanish Peninsula. In 2015, the recorded value was 4.6% higher than the value of the year 2014, and 10.4% below the record of 2007 peak demand which is 45.450 MW (REE, 2016).

In the last 15 years, generation capacity has shown a significant growth with a variation in the mix. RES had almost no share in the mix, nuclear and coal power plants were the main technologies. As it can be seen in FIGURE 4.2, share of wind and solar boomed until the crisis and increased their demand coverage. After the crisis, while coal and CCGT power plants lost their high share in the generation mix, wind and solar PV shares carried on growing apace. In fact, more than 35% of the peak demand was covered by RES in 2015.

One of the main reasons of this growth is definitely linked to the RES support schemes and namely FIT (Ortega, et al., 2013).

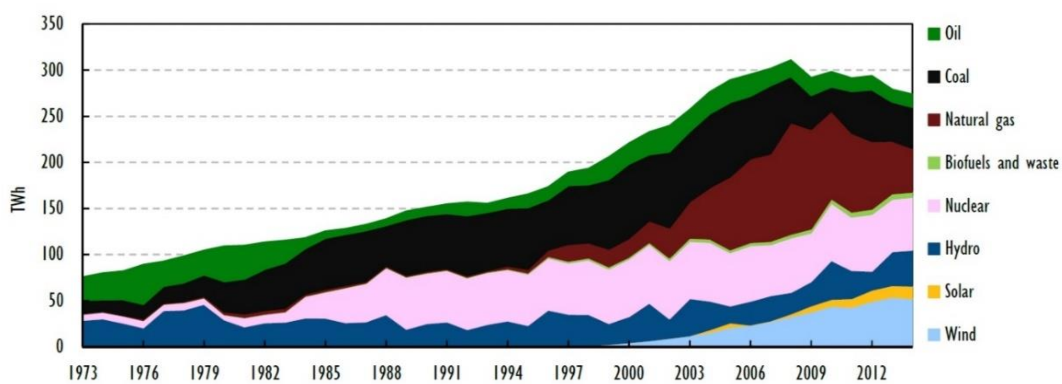

FIGURE 4.2: Electricity generation by source in Spain, 1973- 2014[3] (Source: IEA)

[3] 2014 data is estimated.

However, because of the tariff deficit, Spanish Government had to take some actions which led to a slow down on the investments of RES. They decreased FIT support and eventually suspended it in 2013 by setting a more complex support mechanism explained at the previous chapter. Also, they started to apply 7% generation tax to all generators. Yet, although supports for wind and solar PV technologies have been considerably decreased, decline on RES installation and O&M costs has improved their comparative advantage. For instance, wind turbine price which form the main cost item of the wind power plant installations had a peak in 2008 and 2009 and now it follows a decreasing trend (IRENA, 2015). Similarly, solar PV costs follow the global trend with a more aggressive reduction. Technology innovations on solar energy and the increasing role of China in its market are the main drivers of this improvement (IEA, 2014).

The capacity of wind reached to 22,845 MW and solar PV reached to 6,723 MW which correspond to 22 and 7% of the total capacity in Spanish Peninsula, respectively. The rest of the installed capacity can be seen in the FIGURE 4.3 with their shares and capacities in GW.

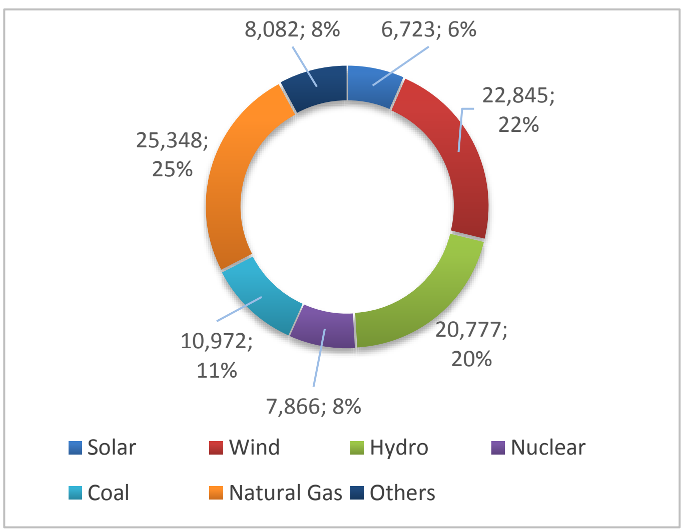

FIGURE 4.3: Installed Capacity Shares in Spanish Peninsula at the end of the year 2015, % and GW. (Source: REE)

High level of installed capacity offers reliable and flexible power system with a low probability of loss load. In Spain, total installed generation capacity reached 102,613 MW in 2015 which is more than twice higher than the record peak demand. The margin between minimum available supply against maximum peak demand[4] in 2015 is 23% and the margin between minimum available supply

[4] Margin is calculated as $\textit{Available Capacity for Spain} = \textit{Minimum Total Available Power Generation Capacity} + \min(0.85 \times \textit{Interconnection Capacity},\ 0.7 \times \textit{Margin against Maximum Instantaneous Demand without Interconnection Capacity})$

against the record peak demand is 13%. While these ratios clearly show the existence of the spare capacity but also provides high system security.

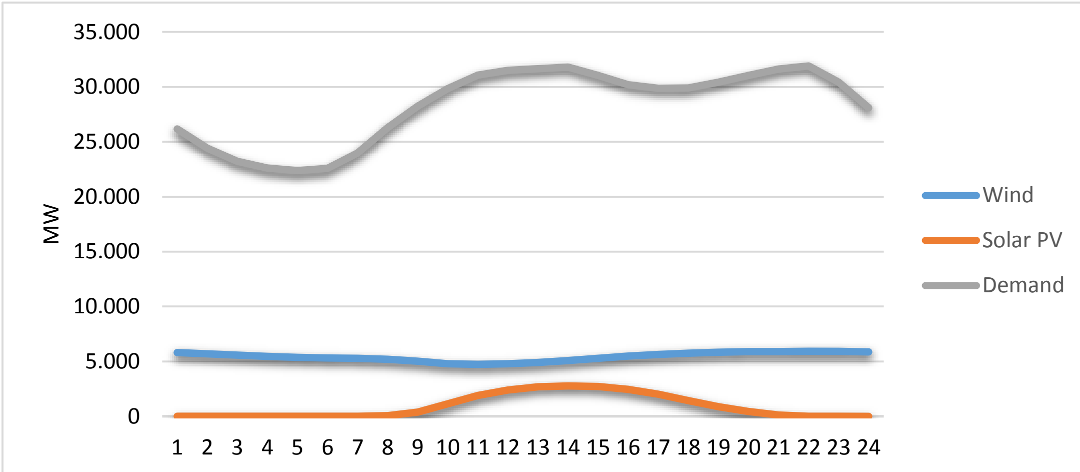

FIGURE 4.4: Average hourly wind, solar PV production and electricity demand in Spain, 2015. (Source: REE)

On a daily level, although the real wind power production in Spain shows highly variable pattern, it is higher overall during the night than during the day (FIGURE 4.4). So high wind production from the evening till the morning covers highest and lowest demand hours of the day. While it substitutes the most expensive units during the peak hours, it cuts into production from the load generators. On the other hand, solar PV power production reaches its peak values at the sunniest hours of the day, from 2 to 3 PM. So, although solar PV produces only a half of the day, it covers the high demand hours, that is, more cost efficient than wind on per unit terms by replacing the most expensive units. Still, due to lower installed capacity of solar PV and its power production unavailability during the no direct sun hours, demand coverage of solar PV stayed 6 times lower than wind in 2015 (from 3.1% to 19.1%) (REE, 2016).

4.3. Portuguese Peninsula

In 2015, electricity demand in Portuguese Peninsula reached 49 TWh and it was covered by coal (28%), wind (23%), CCGT (20%), hydro (17%), solar PV (2%), and international exchange (5%). After the 2008 crisis, the demand and peak demand have followed a downward trend in Portugal, too. Yet, starting from 2013, demand started to grow again and peak demand was recorded as 8,618 MW in 2015. This recorded value was 10% below the record of 2010 peak demand which is 9403 MW (REN, 2016).

In the last 15 years, generation mix has been improved and capacity has been increased in Portugal. Before, hydro, coal and oil power plants were the main technologies. In 1990, CCGT power plants had started to be installed and wind capacity followed the European trend: had increased tremendously until 2009. Similar to Spain, FIT mechanism applied in Portugal is the main driver of the improvement on wind and solar PV capacity in the country. As it can be seen in FIGURE 4.5, steady increase in wind and solar power generation had lost its momentum after the crisis, yet decreasing cost of RES investment as well as the ongoing support mechanisms helped to install more wind and solar PV power plants. Also, variable nature of hydro power production potential throughout years resulted in variety in fossil fuel-fired power generation, that is, change the country’s fuel dependency throughout the years.

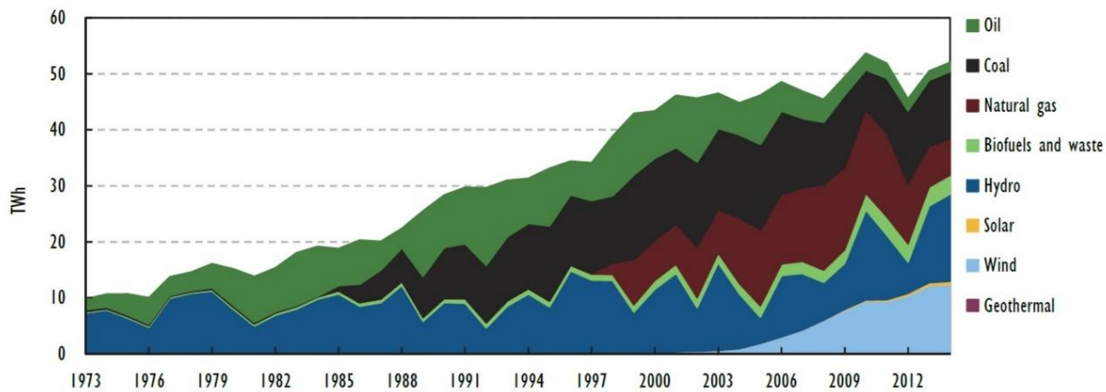

FIGURE 4.5: Electricity generation by source in Portugal, 1973- 2014[5] (Source: IEA)

The capacity of wind reached 4,826 MW and solar PV reached 429 MW which correspond to 26% and 2% of the total capacity in Portugal, respectively. Total installed capacity reached 18,533 MW in 2015 which leaves a high margin against the peak demand, similar to Spanish Peninsula. The margin between minimum available supply against maximum peak demand[6] in 2015 is 45% and against the record peak demand is 35%, considerably higher than the ratios for Spanish Peninsula.

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[5] 2014 data is estimated.

[6] Margin is calculated as *Available Capacity for Portugal=(Installed Conventional Generation Capacity × EFOR)+ min(0.85×Interconnection Capacity, 0.7× Margin against Maximum Instantaneous Demand without interconnection capacity*)

The rest of the installed capacity can be seen in the FIGURE 4.6 with their shares and real capacities in GW.

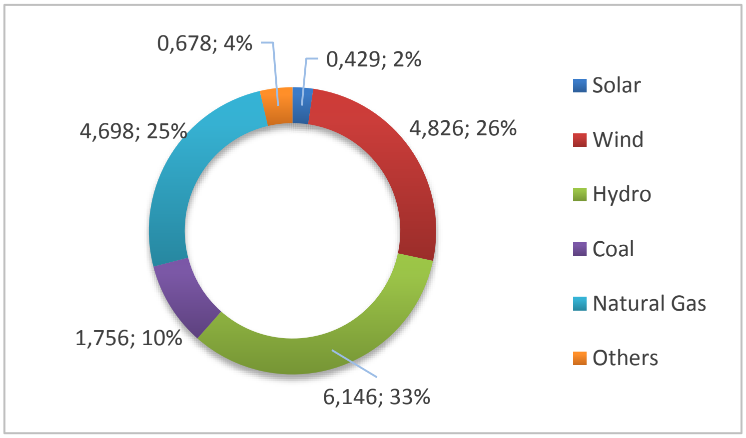

FIGURE 4.6: Installed Capacity Shares in Portuguese Peninsula at the end of the year 2015, % and GW. (Source: REN)

5. Methodology

The aim of this thesis work is estimating the marginal net gains of investments in RES by developing a transparent and simplified methodology which is broadly applicable. It is intended to estimate the net effect of incremental capacity increase of RES at the given location. The proposed methodology focuses on the benefits such as emission savings, operating cost savings and adequacy savings related to displaced energy generation by extra RES production and on costs such as installation, operation and maintenance cost related to extra capacity investment of RES that can be quantified and monetized. The analysis is based on existing technical constraints and regulatory framework of the examined area.

The methodology which has been developed is, in outline, as follows:

- Marginal specific (e.g. PV in a given location) RES capacity increment for a certain period (e.g. 1 year) is assumed.
- The RES hourly production profile (energy) is identified.
- From electricity and fuel prices time series, the marginal technology that is replaced by RES is identified for every hour.
- Saving of the replacement: emission savings, operating cost savings, security of supply improvements are computed.
- Costs related to RES capacity investment are computed.
- Costs and benefits are summarized.

The sequence of this chapter is organized as follows. Firstly, costs and benefits considered in the methodology are reviewed. Secondly, the identification of the marginal unit in each hour is explained. In order to do so, simplified estimations of operating costs are defined. Third, savings due to energy displacement examined separately for avoided emission cost, avoided operating cost and adequacy gains. Finally, net cost and additional tools to analyze the marginal effect of RES are presented.

It is important to remark that the methodology is not appropriate to recommend any specific RES investment or lack of thereof. Such a task should also consider other alternative investments. The results will show that avoided emissions might be a significant reason to support RES deployment. It is simply not possible, out from the results as provided by the proposed methodology, to assess the more efficient alternatives. This kind of general remarks are valid for other costs and benefits as well.

5.1. Benefits and Costs

By installing an additional megawatt of RES capacity in a specific location, number of costs and benefits must be considered. The main cost is the equipment cost, although also costs related to land use, network expansion and broader economic issues (e.g. additional trade debt on national accounts) must be taken into account. On the other hand, some of the benefits relate to system operation (e.g. fuel savings), some others to environmental issues (e.g. pollutant emissions decreases) and some others to broader issues (e.g. imports substitution). Some of these costs and benefits are amenable to quantification, whereas others are much more difficult to quantify. As it is mentioned in Chapter 1, while the savings are namely: (1) emission reduction, (2) improvement of security of supply, (3) fuel import reduction, (4) system operating cost reduction, wholesale electricity price reduction, (5) promotion of technological innovation, (6) job creation, (7) economic growth, the costs of wind and solar PV technologies are (1) installation costs and (2) operation and maintenance costs. Yet, the proposed methodology focuses on avoided emission, avoided operating cost and adequacy savings by incremental capacity increase of wind and solar PV technologies.

5.1.1. Emission benefits

Greenhouse gas emissions, CO_2, CH_4 (methane) and NO (nitrous oxide) emissions, are to blame for climate change, have reached to critical levels, which brings the crucial need of a global control mechanism. Yet, while some needs a global solution and agreement, local level of pollution needs local level care. The pollutants from power industry are mainly SO_2, NO_X, and $PM_{2.5}$ (particulate matter with diameter up to 2.5 micrometers) and they are responsible for acidification, eutrophication of waters and soils, ground-level ozone and particular matter which are directly correlated with the damage to ecosystem and human health (FIGURE 5.1).

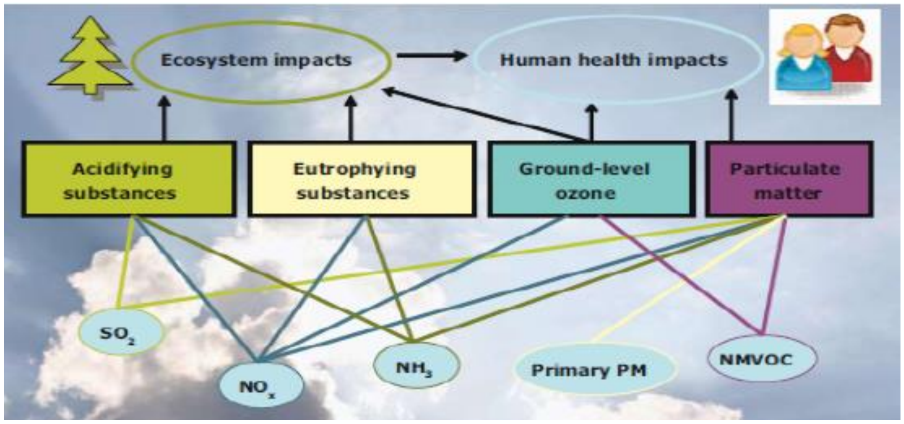

FIGURE 5.1: Air pollutant emissions and their direct effects (Source: EEA (ETC/ACC))

Among all the pollutants shown in the figure, the most harmful pollutant to human health is particulate matter as it penetrates into the respiratory system, can cause cardiovascular problems so that it shortens the life while decreasing the quality of living. In the same manner, SO_2 and NO_X damage both the ecosystem and human health by changing the composition of the soil and water and contributing to the formation of the particulate matter (EEA, 2011).

When industries are examined for each impact, energy industries clearly constitute a high share on acidifying substances and particulate matter (FIGURE 5.2). Similarly, the largest source of greenhouse gas emissions, CO_2 emissions from fossil fuel combustion, are emitted by thermal power plants (Parry, et al., 2014).

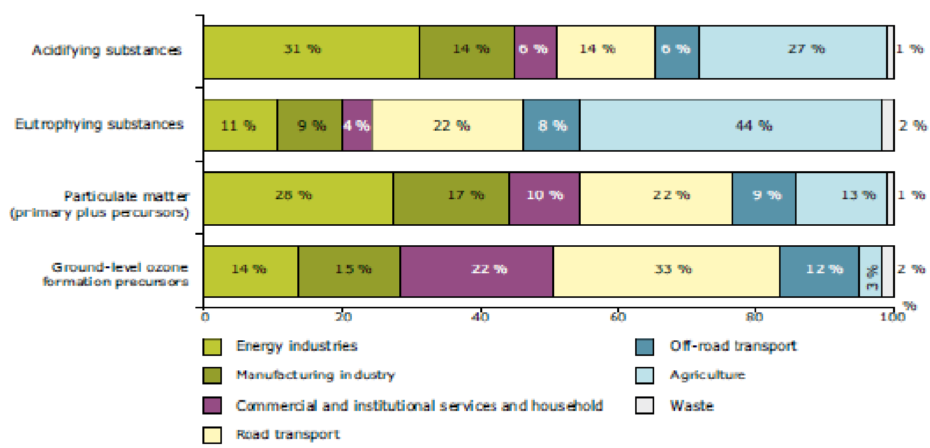

FIGURE 5.2: Shares of industries on the impacts of air pollution in Europe (Source: EEA (ETC/ACC))

For each technology, emission rates vary significantly (FIGURE 5.3). For instance, coal power plants emit all four major pollutants, CO_2, SO_2, NO_x and particulates. On the average, CO_2 emission is the highest while SO_2, NO_X and particulate emissions highly depend on the type of coal and technology used in the plant. Compared to coal-fired power plants, CCGTs are clean generation units in terms of SO_2, NO_X and particulate emissions. However, although they emit minimal amount of NO_X and do not produce SO_2 and particulates, they still emit a significant amount of CO_2.

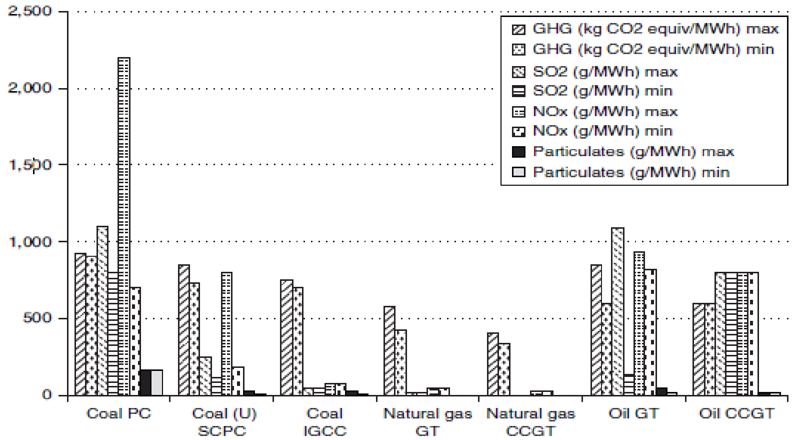

FIGURE 5.3: Atmospheric pollutants from electricity – fossil (Sources: EC, 1995a; IEA- ETSAP, 2010; EC, 1995b; US-EPA, 2011a; EC, 1995b; US- EPA, 2011a; IEA- ETSAP, 2010b)

Assuming the fossil fuel-fired power plants respond to the increase of renewable output, an additional energy generation by RES replace the energy generated by the most expensive generating unit at the dispatch which are mostly fossil fuel-fired power plants. In other words, increase in RES output replaces high emissions generations such as coal and CCGT generation unit with zero emission units. Clearly, the direct effect of this replacement is the avoided emissions.

5.1.2. Operation savings

By the energy generation displacement from thermal power plants to renewable energy generators, energy is produced by renewable energy generators instead of the marginal unit of that hour. Since operating cost of RES is very close to zero, the net operating cost savings will be equal to the operating cost of the marginal unit. Keeping in mind that the marginal unit which responds to the output change of RES is a fossil fuel-fired plant, and the savings correspond to the replacement are the operating cost of that unit.

Operating cost of fossil fuel-fired plants are formed by the variable energy generation costs and administrative charges. While production cost is the total of fuel cost[7] and variable operation and maintenance (O&M) costs, administrative charges include fuel and per energy generated taxes[8].

In addition to the direct variable costs, some of the fixed costs such as start-up and shut-down costs[9] are internalized in the bids of decentralized competitive wholesale markets. Moreover, at the power systems including the external markets like carbon markets, bids internalize the result of that market (Fabra & Reguant, 2014). Nevertheless, while fuel cost without a tax, O&M costs, start-up and shut-down costs are the real operating costs of power producers, administrative charges and internalized carbon market price should be evaluated separately as they are the result of regulatory intervention and not a real cost component of the operating cost. Tax, by definition, is the compulsory payment to the government on business profits or added to the cost of goods, services and transactions. So, while it is a cost from the power producers' point of view, it is only transfer of funds from power producers to the government. An analysis of policy intervention carry a system-wise approach and should exclude these charges while evaluating the effect of RES investment to the system. They depend on regulatory framework and do not form the real operating cost of the units.

5.1.3. Adequacy benefits

Apart from the replacement values, more generated energy by RES decreases hourly net demand of the system and increases margin between hourly net demand and conventional generation capacity. This margin is defined as system generation adequacy level provides a basis to develop an approximate way to quantify adequacy costs that will be used in this thesis. Although valuation of the improvement of supply adequacy due to RES capacity is short-term analysis, it gives long-term signal to system operators on the RES contribution to the supply adequacy and to the regulatory bodies on valuation of RES.

[7] Fuel cost includes fuel price, fuel tax and access tariff for natural gas
[8] Electricity network tariffs for the EU and generation tax for Spain.
[9] Start-up cost is the cost of fuel to reach the needed boiler pressure and temperature, and shut-down cost is the cost of unburned fuel that is wasted, are the one time fixed costs (García González, 2014).

5.1.4. Technology Cost

A marginal specific RES capacity increment for a certain period requires its corresponding capital and operating expenditure for installation and operation of that unit. Among all the technology cost calculations, levelized cost of electricity (LCOE) is a very suitable tool for per MWh calculations since it represents per unit of hourly energy generation cost of building and operating a generating plant over an assumed financial life and duty cycle (US Energy Information Administration, 2015). Nonetheless, as Borenstein (2012) states, the value is highly sensitive to the engineering factors of the technology, capacity factor, expected lifetime, inflation rate, and real interest rate. Keeping in mind the fast cost reduction of wind and solar PV technologies at the recent years, and high variation on the components of LCOE calculations in each country, it is necessary to use most recent, sensible values.

5.2. Marginal Generation Unit

Before moving forward to set the net value of incremental RES investment, identification of marginal generation unit of each hour is necessary so that hourly net effect of the marginal technology can be defined. In order to do that, a simple but robust method is developed and its robustness is tested by empirical studies.

In the decentralized wholesale markets, a single price is set for each market and this price is equal to the operational cost of marginal technology if the market is competitive. So, knowing the hourly operating cost of all power plants in the electricity system and their availabilities, one can define the marginal technology of that hour. However, cost data of the power plants is confidential in the competitive liberalized markets. By simulating the system, estimations can be found; yet the model is very complex and needs expertise to analyze. As another way, by looking at the bids of each hour, the bid matching the market price and its corresponding entity can be identified. However, integrated electricity market in different sub-markets complicates to identify the marginal unit. Also, the bids may not be published by the systems operator and even if they are available, processing that raw data may not be efficient.

Although it is possible to identify the marginal technology in a high confidence interval by previously discussed models, these approaches do not provide the objective of this study, the simplicity and transparency in the methodology. Reliable and robust identification is also possible by setting sensible operational cost ranges for each technology for every hour so that the marginal technology of each hour can be defined by looking at the hourly market price and operational cost ranges of each technology. The technology which contains the market price on its operating cost range will be defined as the marginal unit of that hour. For instance, at the power systems in which two technologies are marginal most of the time, one threshold separates the most expensive unit from the one level below technology at the dispatch. Second threshold sets a lower boundary between the second most expensive technology and other technologies that are out of focus.

One way to define the ranges is calculating the average operating cost of displaced generation unit by its main cost drivers and choosing a sensible threshold value in between which captures the marginal technology. Another way is calculating the maximum and minimum hourly operating costs of each technology and constructing the threshold according to that. This approach assumes that

- the analyzed electricity market is competitive so that price of electricity is equal to the operational cost of marginal technology and merit-order dispatch is seen,
- RES industries are competitive,
- the electricity market is clearly delimited so that trans-boundary impacts can be ignored or properly accounted for,
- demand side management does not have a significant effect on the system, customer behavior is not affected by RE generation, and
- only fossil fuel production in the region will be affected by an increase in renewable output.

After the selection of the thresholds separating hourly operating cost range of technologies, marginal generating unit of each hour can be defined and expressed by the parameter α which takes the value "1" when the technology t is marginal at the hour h or "0" otherwise.

5.2.1. Operating Costs

Average operating cost of technologies is the key to set the ranges so that minimum and maximum levels can be defined according to the results. Operating cost is previously defined as variable production costs and administrative charges. While calculating the thresholds, internalization of the fixed costs and access tariff into the bids are neglected. Only time dependent cost components: fuel cost and carbon price are included in the calculations together with logistics costs, O&M costs, and taxes.

5.2.1.1. Fuel Cost

Agents must internalize fuel cost in their bids which, in fact, can be written as the fuel price times the heat rate. The heat rate indicates the energy needed to generate one unit of electricity by a power plant and it is equal to the inverse of the efficiency of the power plant (EIA, 2016). In other words, it is the parameter that transforms fuel prices into variable costs.

Technical boundaries of the power plants allow to operate only in between the minimum power level $\underline{q_t}$ and the maximum power level $\overline{q_t}$. The relationship between input and output are plant and technology specific and may have non-convexities; nevertheless, input-output curve can be linearly approximated (FIGURE 5.4). By assuming a linear relationship between the input energy and electricity produced, the linear function which consists of a fixed term β, net fixed consumption rate, and a variable term α, net variable consumption rate can be calculated. (García González, 2014)

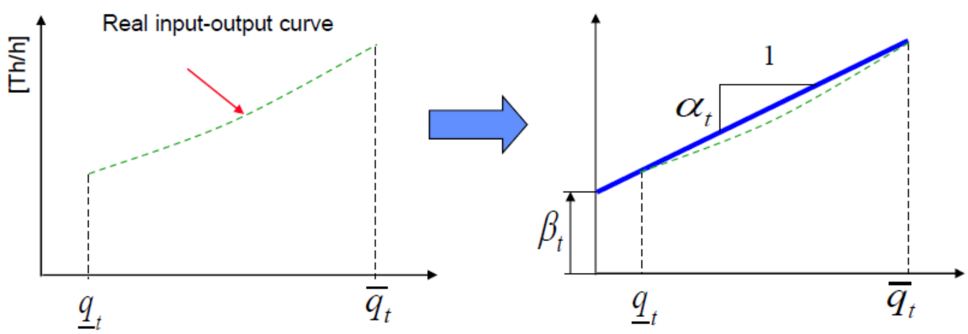

FIGURE 5.4: Thermal unit input-output curve in thermies per hour to gross output (Source: IIT)

For the cases that the hourly production level of the thermal units is available, hourly heat rate of each unit can be calculated. However, this plant specific data is confidential. That is why, an approximation will be used to reach average heat rate for each thermal plant:

$$Heat\ rate_t \left[\frac{th}{MWhe}\right] = \frac{\beta_t \left[\frac{th}{h}\right] + \alpha_t \left[\frac{th}{kWhe}\right] \times PR_t[\%] \times \overline{q_t}\,[kWe]}{\overline{q_t}\,[kWe]} \quad for\ each\ thermal\ power\ plant\ t$$

where PR_t is the average electricity generation over the maximum net power output of generators.

Power producers often enter into long-term contracts for the purchase of the fuel and these contracts are usually take-or-pay contracts which penalize the buyer for not purchasing a minimum amount of fuel over a predetermined period (Vázquez Martínez, 2011). However, these strict contracts are risky because of the unforeseen future events which may cause lower fuel demand than anticipated. As a consequence, at some power systems, take or pay contracts are modified into flexible contracts, and long term contracts are modified into short term ones. Also, producers hedge according to future price so that even if the fuel price changes in the present, in total, they are only affected by the future price of that day. That is why, while fuel cost depends on the contract prices for some power systems, it is linked to the future fuel prices for the systems which has higher exposure to market prices.

Transportation cost and the fuel tax are the last components of the fuel cost. It is called as logistics cost for coal and access tariff that the CCGT power plants pay for the access to the gas pipes. Logistics cost is fixed per ton of coal while access tariff depends on available capacity of the pipe, demand of gas etc. Finally, fuel cost is

$$Fuel\ Cost_{f,t,d} \ = \ \left(Fuel\ Price_{f,d} + Fuel\ Tax_t\right) Heat\ Rate_{t,f} + Transportation\ Cost_{t,h}$$

where f denotes the fuel type, t technology, and d day.

5.2.1.2. Operation and Maintenance Costs

The operation and maintenance (O&M) costs of power generation have fixed and variable components, where fixed O&M costs (€/MW/year) includes all cost which are independent from the operating conditions and generation level of the power plant, and variable O&M costs (€/MWh) depend on the output level. Traditionally, they are calculated by dividing the total relevant annual costs with the net generating capacity for fixed part and net annual generation for variable part (Energinet, 2012). So, it stays constant per MW and MWh for each technology.

In this study, only the variable component of the O&M costs are considered in forming the operating costs. The components that the power producers include to the variable O&M costs and how they internalize it in their bids is confidential. According to Energinet (2012), total variable O&M costs include output dependent repair and maintenance, spare parts treatment and disposal of residual, and consumption of auxiliary materials, e.g. water, lubricants, fuel additives. However, which costs are to be included to the fixed and variable O&M costs is a controversial issue. This confidential data does not necessarily include the same cost components in each power plant.

Variable O&M costs are traditionally included to operating costs as a constant value per MWh; however, this simplified internalization may not be valid in all the power systems. Rodilla et al. (2014) state that directly adding a constant variable O&M costs to the operating cost calculations is not well suited for the systems under heavy cycling regimes. High frequency of start-ups increases the O&M costs on the dispatch, that is, variable O&M costs need a component which contains its effect on each start-up apart from its constant per energy component. Yet, it is not straightforward to identify their values since they are both highly dependent on the operating conditions.

5.3. Avoided Emission Cost

Avoided emission cost is the measure which quantifies total health and environmental damage caused by fossil fuel power generation in the region for each pollutant p. As it is mentioned before, the parameter $\alpha_{t,h}$ represents the identification of the marginal technology t for the hour h by taking the value 1 when fossil fuel-fired technology t is marginal at the hour h or 0 otherwise. Emission factor ($EF_{p,t}$) defines emission rate of the pollutant p for the technology t, while emission cost (EC_p) captures the monetary value of the health and environmental damages of the pollutant p. Besides, they both represent the marginal values. By multiplying renewable production output $q_{RES,h}$ at the hours when the technology t is marginal with the emission factor of each technology, avoided emissions of the pollutants can be found for a given period H.

$$AE_{r,p} = \sum_{h=1}^{H}\sum_{t=1}^{T}\left(\alpha_{t,h} \cdot EF_{p,t} \cdot q_{r,h}\right) \qquad for\ each\ pollutant\ p\ and\ RES\ technology\ r$$

By multiplying avoided emissions of the pollutants with their corresponding EC, and summing the results up, avoided emissions cost (AEC) and average avoided emissions cost ($AAEC$) in the given period H are found for the RES technologies and pollutants.

$$AEC_{r,p} = EC_p AE_{r,p} \qquad for\ each\ pollutant\ p\ and\ each\ RES\ technology\ r$$

$$AAEC_{r,p} = \frac{AEC_r}{\sum_{h=1}^{H} q_{r,h}} \qquad for\ each\ pollutant\ p\ and\ each\ RES\ technology\ r$$

This approach assumes that only marginal technology responds to the output increase of renewable energy.

5.4. Avoided Operating Costs

Assuming that (1) the market is competitive, (2) power system is disconnected from the other power systems, and (3) only marginal power plants will respond to the increase of renewable energy generation, hourly market prices will reflect the exact operating cost of the marginal power plant of that hour in the same region.

By identifying the marginal technology of each hour, avoided operating cost of that technology in that particular hour can be captured. Total avoided operating cost ($TAOC$) and average avoided operating cost ($AAOC$) are:

$$TAOC_r = \sum_{t}^{T} \sum_{h=1}^{H} \alpha_{t,h} NMP_h q_{r,h} \qquad for\ each\ RES\ technology\ r$$

$$AAOC_r = \frac{\sum_t^T \sum_{h=1}^H \alpha_{t,h} NMP_h q_{r,h}}{\sum_{h=1}^H q_{r,h}} \qquad for\ each\ RES\ technology\ r$$

The variable q_t represents the additional energy produced by the technology t in the hour h a result of incremental capacity increase and multiplied by the net market price[10] *(NMP)* of that hour to calculate the total avoided operating cost *(AOC)*.

By subtracting the marginal taxes and internalized carbon cost, total avoided real operating cost ($TAROC$) and average avoided real operating cost ($AAROC$) of each RES technology can be found. Compared to $TAOC$, this value gives the correct measurement of system-wise marginal effect of RES investment.

5.5. Adequacy Gain

Electricity is an essential component of our social and economic actions, which makes its availability a crucial concern in all the countries. Especially at the most industrialized and developed countries, security of supply is monitored by the regulators attentively in the light of predefined measures and

[10] Final hourly spot market price of the electricity market.

directives. The EU Directive 2005/89/EC of January 2006 defines “security of electricity supply” as “the ability of an electricity system to supply final customers with electricity” and set measures to ensure: (a) an adequate level of generation capacity, (b) an adequate balance between supply and demand, (c) an appropriate level of interconnection between Member States for the development of the internal market.

Security of supply has four dimensions from short-term to very long term: security, firmness, adequacy and strategic expansion policy (Pérez-Arriaga, 2013). Security is “the ability to withstand sudden disturbances, such as electric short circuits or unanticipated losses of system components” and adequacy is “the ability to supply the aggregate electric power and energy requirements of the customer at all times, taking into account scheduled and unscheduled outages of system components” in which both are essential for system reliability (ENTSO-E, 2015).

System generation adequacy level can be measured as the margin between net demand and the sum of available generation capacity in the region and available interconnection capacity. Although this measure provides us a necessary number to analyze system reliability, it is not immediately translated into an economic figure. However it provides a basis to develop an approximate way to quantify adequacy costs that will be used in this thesis.

Generation adequacy concerns arise whenever the net demand, that is, the difference between demand and non-dispatchable generation is so high that there is a significant risk for dispatchable generation to not be able to provide all the required demand. Therefore, it is assumed that adequacy risk, and as a consequence adequacy cost, is a function of the difference between dispatchable generation capacity and net demand or adequacy margin (AM), as a percentage over available generation capacity and imports, that changes from hour to hour so that output increase of renewable energy generation will decrease the adequacy risk by decreasing the net demand.

Adequacy part of security of supply is short term issue but gives long term signals to the system operators. Cost incurred by so

$$Adequacy\ Cost = f(\ AM\ )$$

Consequently, inter-temporal dependencies are neglected. This is consistent with usual practice in thermal dominated systems, although it raises concerns for hydro dominated ones.

Value of Lost Load (VOLL) is the amount that consumers should be willing to pay avoid power disconnection, and in other words, it is the adequacy cost when generation margin is zero (Newbery, 2015). Therefore, adequacy cost when adequacy margin is greater than zero should be proportional to VOLL.

$$Adequacy\ Cost = VOLL \times g(\ AM\ )$$

The adequacy cost we are interested in is the marginal adequacy cost, that is, the cost on increasing demand by 1 MW in an hour. So, g is the probability of not being able to supply all the demand. The reason is that, under this hypothesis, increasing the demand in 1 MWh increases the economic cost in VOLL €; whereas if the generation is able to supply the demand a marginal increment of it does not cause an additional cost.

Therefore, function g carries only technical information about the probability of not supplying all the demand given the system technical characteristics. Its computation is a complex engineering task that will not be further pursued here. Instead, a heuristic approach will be followed. If the margin is nil, the probability of losing some load is one, and g = 1. On the other hand, system operators typically consider a 10% margin as a safe one, which implies that they consider that over that threshold the adequacy cost is low enough. Therefore, a heuristic function g is defined as follows:

- g (0) = 1
- g (10% margin) = 0.0001
- g is exponential

Finally, the adequacy value for adequacy margin is considered to be

$$Adequacy\ Cost = f(AM) = VOLL \cdot e^{\beta \cdot AM}$$

where β is $\frac{\ln(0{,}0001)}{10\%}$ and AM is defined between 0% and 100% and the corresponding function can be drawn as below.

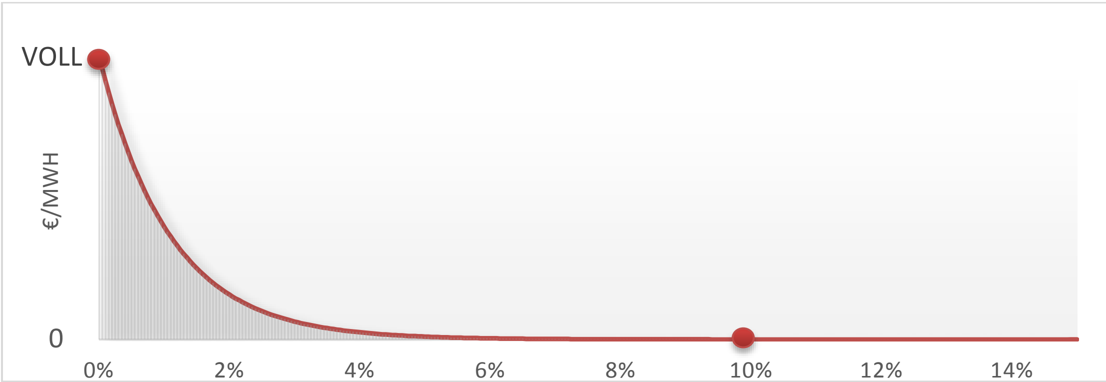

FIGURE 5.5: Adequacy function

Total adequacy gain (AG) is

$$AG_r = \sum_{h=1}^{H} \left[f_h\left(AM_{old,r}\right) - f_h\left(AM_{new,r}\right) \right] \qquad for\ each\ RES\ technology\ r$$

where AM_{old} is the margin at the initial RES capacity and AM_{new} is the margin after the reduction of net demand as a result of additional energy generation by the incremental increase in the capacity of RES.

5.6. Net Costs

Finally, net effect of marginal returns on RES investment is computed with LCOEs. The total net marginal cost is equal to the difference between the technology cost and total benefit gained in the corresponding time frame. Total and average net costs are:

$$TNC_r = LCOE_r \sum_{h=1}^{H} q_{r,h} - \left(\sum_{p}^{P} AEC_{r,p} + TAOC_r + AG_r \right) \qquad for\ each\ RES\ technology\ r$$

$$ANC_r = LCOE_r - \frac{\left(\sum_p^P AEC_{r,p} + TAOC_r + AG_r\right)}{\sum_{h=1}^{H} q_{r,h}} \qquad for\ each\ RES\ technology\ r$$

In addition to net cost of marginal RES investments, another measure is developed: net costs required to avoid a ton of emissions which can be named as average displacement cost (ADC) of emissions.

$$ADC_{r,p} = \frac{LCOE_r \sum_{h=1}^{H} q_{r,h} - (TAOC_r + AG_r)}{\sum_p^P AE_{r,p}} \quad for\ each\ RES\ technology\ r\ and\ pollutant\ p$$

6. Data and Implementation to the Iberian Electricity System

In this chapter, the data sources used in the study are defined and the implementation of the methodology is presented. In the first section, all the data is described and the data sources are provided. In the second part, implementation of the developed methodology to the Iberian Power System is explained and the results for the year 2015 are revealed. Finally, robustness of the marginal unit identification is analyzed in the last section.

6.1. Data Sources

The approach of this thesis is data intensive and broadly applicable. Developed methodology is transparent and requires using public data. As the methodology is implemented to the Iberian Peninsula, data are obtained from their Transmission System Operators mainly for the year 2015. However, some of the data needed to be adapted to the system under some assumptions. Also, because of the unavailability of some data for Portugal, Spanish data is aggregated for the Iberian Peninsula considering its dominant position at the Peninsula. The general attitude and data gathering relies on the facts discussed in the Chapter 4: Portuguese and Spanish side of the Iberian Peninsula are integrated and functions as a single market which is almost fully integrated with a less than 9% of market splitting.

Firstly, technology specific costs are presented by dividing into the groups of fossil fuel power plants and RES. Fossil fuel power plants of the interest are coal and CCGT power plants in Iberian Peninsula since they are mainly marginal technologies while RES includes wind and solar PV in the same region. Secondly, system data of Iberian Peninsula is given. After these two, environmental data which is used for the computations of external benefits are discussed. Finally, this part of the chapter ends with value of loss load and taxes.

6.1.1. Technology Specific Costs

6.1.1.1. Fossil Fuel-Fired Power Plants

Hourly electricity market prices: Hourly electricity market prices for Spain and Portugal are published in the website of the market operator of the Iberian Peninsula, OMIE, separately for the day-ahead and intraday markets[11]. However, since collecting the results via OMIE website is a cumbersome task, it is gathered from the information system of the Spanish Transmission System Operator[12] (REE). In order to obtain a single hourly price, I use hourly day-ahead price of Spain and update it with the weighted average of intraday market final results by demand bought in each session as proxy of real-time prices of Iberian Peninsula. This proxy is referred as net market price.

Fuel prices: The most liquid market prices of coal and gas which are reasonable to use in Iberian Peninsula are chosen, API2 Index and UK Natural Gas Futures.

The indexes of API4 and API2 are the most liquid future prices, also they are the most commonly used indexes for hedging purposes for coal. For instance, 90% of the world coal derivatives are based on API2 and API4 indexes. In this study, API2 index is preferred. Being the average of the Argus cif Rotterdam assessment and HIS McCloskey's northwest European steam coal marker, it is the benchmark price reference for coal imported into northwest Europe (Argus, 2016).

UK Natural Gas Futures Price is the future contract price for physical delivery of rights at NPB (National Balancing Point) Virtual Trading Point operated by the transmissions system operator in the UK (ICE, 2016). It is originally given as USD/MMBTU and USD/EUR exchange rate of that day is applied to obtain EUR prices for calculations.

Carbon prices: While defining the components of the bidding prices, direct operational costs are not the only factor to be considered. However, external markets may have an effect on the bidding prices. European Emissions Trading System (EU ETS) as a cap-and-trade program, apart from its significant effect on overall reduction of emissions at minimum cost, rises the market prices. (Fabra & Reguant, 2014) In their paper, Fabra and Reguant (2014) state that CO_2 prices have a full pass through rate,

[11] http://www.omel.es/files/flash/ResultadosMercado.swf, last accessed June 06, 2016.
[12] https://www.esios.ree.es/en/market-and-prices, last accessed June 06, 2016.

especially when the big firms operating in the power market and demand is inelastic. In another words, CO_2 price in EU ETS market directly internalized in the bids and increases the market price exactly the same amount resulted in the EU ETS.

Based on the literature above, full-pass through rate is assumed for the market of interest and direct projection of daily carbon prices which are obtained from European Energy Exchange are included to the operating cost of the coal and CCGT units.

Operating cost: After the identification of the marginal generating unit of each hour, their corresponding net market prices are used as a proxy for the operating costs of the marginal units at that hour.

Variable O&M Costs: Traditionally, variable O&M costs of generation units are defined as a constant value per MWh of energy produced and internalized in the bids according to that. The difficulty on setting variable O&M cost for the conventional units coal and CCGT is its confidentiality in liberalized markets and a low number of study on the calculation of variable O&M costs. Traber and Kemfert (2011) and Mott MacDonald (2010) provide their estimates for Germany and UK, respectively while Capros (2011) provides general values for EU-27& EU candidate countries (see TABLE 6.1).

TABLE 6.1: Variable O&M costs estimates for coal and CCGT power plants

Sources	Coal	CCGT
	€/MWh	
(Traber & Kemfert, 2011)	2.3	1.3
(Capros, 2011)	2.4	2.1
(Mott MacDonald, 2010)	2.5	1.7
Personal communication (for Spain)	3.0	1.0

However, as it is mentioned at the methodology chapter, high RES generation share in Iberian electricity market may change the hourly variable O&M costs internalization. High intermittency effect increases cyclic operations in coal and highly in CCGT power plants and results in hourly variety in variable O&M costs (Rodilla, et al., 2014).

Within the simplified methodology that I follow, only constant component of the variable O&M cost is included to the calculations since unit commitment model needs to be solved to set the variable cost with its two components (Rodilla, et al., 2014). This value obviously needs to be lower than results in the literature since it represents only the constant part of variable 0&M costs, not the total of it. Considering the estimations in the literature as well as the average values obtained by personal communication, constant variable O&M cost is assumed as 2 €/MWh for coal and 1 €/MWh for CCGT power plants.

Logistics cost: Although this value varies depending on the internal logistics of the coal power plants, it can be classified in two different values. In Spanish Peninsula, most of the coal plants are at the coast because of the lower logistics cost. This situation is similar in Portugal as well. As a long and narrow country, it has all power plants at or very close to the coast. For the plants at coastal zones, logistics costs are rather lower than the inland power plants. While logistics costs for imported coal is 2 $ per ton for the coastal plants in Iberian Peninsula, it is 18 $ per ton on average for the inland plants[13].

6.1.1.2. Renewable Energy Sources

Technology cost for wind and solar PV: Rapid drop of technology costs of renewable energy power sources at recent years makes the usage of the most recent, reliable data on costs to obtain a sensible analysis essential in the study. That is why, after a detailed literature review, finally two sources are chosen for the initial comparisons. These data are taken from the well-known international intergovernmental organization IRENA (International Renewable Energy Agency) and a private data company providing news, data and analysis on carbon and clean energy markets, Bloomberg New Energy Finance (Bloomberg New Energy Finance, n.d.).

TABLE 6.2: Literature Review on Onshore Wind Technology Cost

Source	Country	LCOE
(Bloomberg New Energy Finance, 2013)	Spain	88-91 (2013 USD/MWh)
(IRENA , 2014)[14,15]	Spain	70.24 (2014 USD/MWh)

IRENA data for Spain is chosen to estimate LCOE of onshore wind technology in Iberian Peninsula for the year 2015. As it can be seen in the FIGURE 6.1, downward trend reaching almost half price

[13] Personal communication.
[14] This database provides annual estimates from 1990 until 2014 and allows to forecast LCOE for the year 2015.
[15] WACC is taken 7.5%.

of 1990 in 2003 was interrupted in 2003 and economic crisis increased significantly after 2006. After reaching a peak at 2008, LCOE again followed a decreasing pattern thanks to the reduced cost of investment. In order to eliminate the effect of 2009 crisis and reflect the downward trend, the last 5 year data after 2009 crisis until 2014 is used for forecasting. By first and second degree linear forecasting, two different functions developed with R^2 values higher than 90% and corresponding estimates calculated for 2015 (see TABLE 6.4).

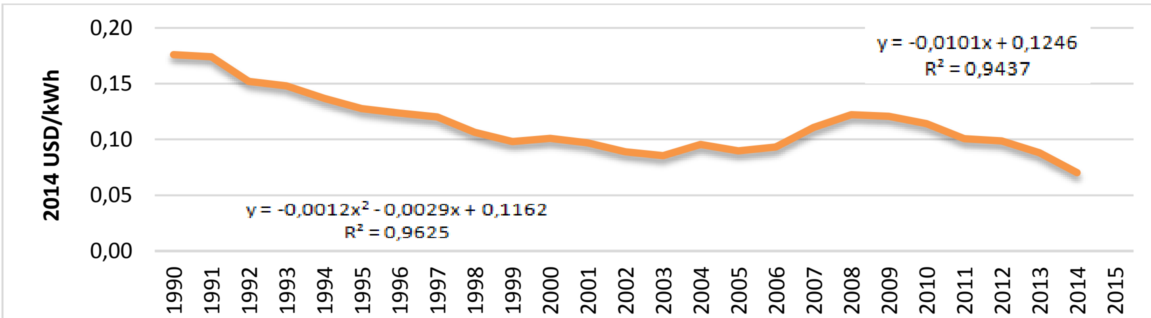

FIGURE 6.1: Weighted Average LCOE of Onshore Wind, Spain (Source: IRENA)

Technology cost of solar PV is even more limited in the literature. Although IRENA database contains yearly data for LCOE from 2011 to 2014, data is aggregated for Europe shows a wide range. Comparison of the IRENA and Bloomberg New Energy Finance data show that solar PV cost in Spain is close to the lower boundary of the European aggregated value. Yet, an important difference between these two sources is that while the former uses 6% WACC, the latter uses 7.5%.

TABLE 6.3: Literature Review on Solar PV Technology Cost

Source	Country	LCOE
(Bloomberg New Energy Finance, 2013)	Spain	109 (2013 USD/MWh)
(IRENA , 2014)	Europe	120-250 (190) (2014 USD/MWh)

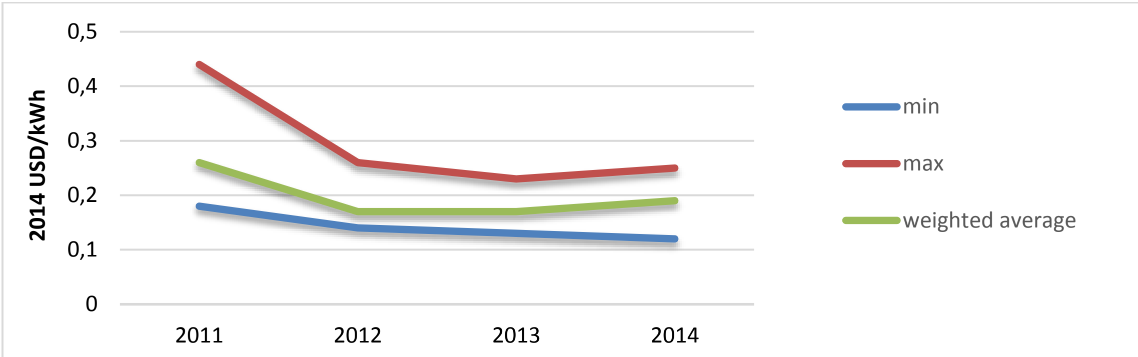

FIGURE 6.2: LCOE (Europe) - 2014 USD/kWh (Source: IRENA)

For solar PV, 2013 Spanish data of BNEF report is used for yearly cost calculations by carrying the value to 2015 €.

LCOE estimates of wind and solar PV in Iberian Peninsula are shown below.

TABLE 6.4: LCOE estimates for wind and solar PV (2015 €)

RES Technologies	**LCOE**
	€/MWh
Wind	54
Utility Scale Solar PV	99.94

6.1.2. System Data

6.1.2.1. Demand, production of each technology, and total available power generation capacity

Data are gathered from the information system of the Spanish Transmission System Operator (REE). In Iberian Peninsula, coal or CCGT units are mostly the marginal generators which means that they will respond to the changes in RES generation. Co-generation, biomass, hydro, nuclear production are excluded because these units are presumably unaffected by the increase in RES capacity. Also, only the production of wind and solar PV used and solar thermal is excluded because energy generation by solar thermal plants is not necessarily proportional to its capacity increase. They can store energy for future-use. For illustrative purposes, production profiles of wind and solar PV are taken from their hourly aggregate production data for 1 MW of capacity increase in each technology.

6.1.3. Environmental Data

6.1.3.1. Emission Damage Costs

Defining an appropriate damage cost of CO_2 emissions is not straightforward and countries as well as unions may have their own approaches. However, climate change is a global issue and the damage caused by CO_2 emissions should not depend on where and how it is emitted. A single price to value environmental damage should be set globally (Parry, et al., 2014). Moreover, setting an appropriate discount rate is another delicate issue. CO_2 accumulates in the atmosphere for decades and gradually increase its concentration. So while market interest rates can be used to discount as a standard way, below market interest rates can also be considered as future generations will be affected by accumulation of CO_2 emissions more than current generations. FIGURE 6.3 shows the difference on the values by different discount rates. Under the assumption of higher effect of global climate change to the future generation, social cost of carbon increases.

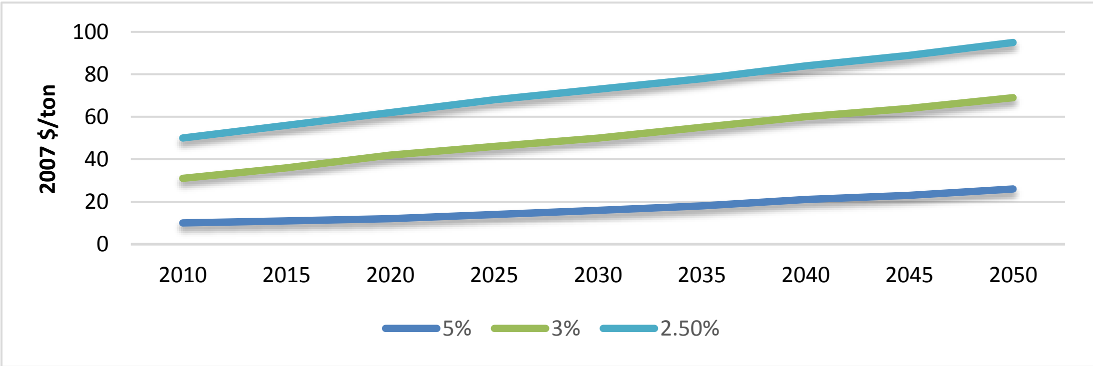

FIGURE 6.3: Social cost of CO_2, by discount rates (Source: IAWG (2015))

While damage of CO_2 emissions needs a single, global damage cost, local level of pollution needs local level valuation. The pollutants SO_2, NO_X, and $PM_{2.5}$ have more of a local damage than global as their densities change regionally. The heaviest pollutant among the three, $PM_{2.5}$, is also the most harmful one to human health. It penetrates into the respiratory system and causes serious cardiovascular and lung diseases (EEA, 2011). As it is the heaviest, its dispersion rate is less than the others, and its damage highly depends on the location of the coal power plants as well as the height of the chimney of the plant. SO_2 and NO_X are also harmful to the human respiratory systems by their negative effect on lung function. What is more, NO_X relates to eutrophication and they both contribute to acidification. That is why, their damage costs need to be calculated according to location of the power plants in the region selected, exposed population, population characteristics etc.

Two main approaches in the literature for impact assessment in order to define the external costs of emissions in the literature are defined below.

- Installation-based
    - Environmental impact assessment: A matrix is set which matches the actions of the project with the environmental aspects.
- Process-based
    - Life Cycle Analysis: Analytical method which allows the assessment of the environmental impact of a product taking into account the whole life cycle. It is complex and requires full transparency.
    - Fuel Cycle Analysis: It contains macro and microanalysis approaches. Macro/top-down approach is easy, not specific and does not provide marginal values. Micro/bottom-up approach is complex but it gives the marginal values. It is transparent and also technology specific. (Linares, 2016)

While macroeconomic studies carried by well-known international agencies examine the impact of each power plant technology on GDP, employment, wealth, and trade balance on an aggregate basis, microanalysis approach is in line with this study. It gives the marginal external cost of each technology or pollutant which allows obtaining the targeted results of this study. For instance, the International Renewable Energy Agency (IRENA) has recently published a report “Renewable Energy Benefits” which provides the first quantification of the macroeconomic impact of doubling the global share of renewables in the energy mix by 2030. They provide their forecast on the effect of the GDP, welfare, jobs and trade balance for each country with the main variables defined in a range: fossil fuel subsidies, fossil fuel prices, technology costs, carbon prices etc. Another report carried by the Association of Renewable Energy Companies (APPA) in Spain follows the same approach and examines the yearly macroeconomic impact of renewable energy sources until 2014. Contribution to GDP, to direct and indirect employment, energy price, fossil fuel import and CO_2 emission savings, energy price are shown in the report, yet some results are not delivered for each technology. Although these studies clearly show direct and indirect effect of RES, these are aggregate which means that incremental effect of RES in the system is not provided. On the other hand, the main extensive country specific studies which follow a bottom-up approach are the ExternE Project (1998, 2005) and IMF study, “Getting Energy Prices Right” (2014).

ExternE project, which was launched in 1991 and published its results for 15 countries in 1999. It was the most advanced study following bottom-up approach on monetizing the effect of the use of energy associated with fuel cycles of each technology carried out as a collaborative project of European Commission and US-DOE. The methodology that they develop, Impact Pathway Approach, follows a stepwise approach from pollutant emissions to their monetary equivalent at each country of interest. As it can be seen from the diagram taken from ExternE document (FIGURE 6.4), the approach follows four main steps. Firstly, site and technology specific data in kilogram per year of particulates is collected and characterized, the spread of the pollutants and the exposed population are defined. After the identification of the consequences and impacts of each pollutant, each impact monetized according to their damage. By this way, finally marginal effects of each pollutant in each county are found in monetized terms.

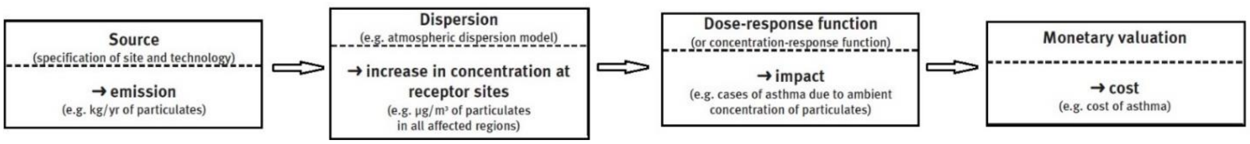

FIGURE 6.4: The impact pathway approach (Source: European Commission, 2003)

The results of study vary depending on the location of the power plants, location of the supporting activities, technology used, type of fuel used, the source and the composition of the fuel used for each country (European Commission, 1999). That is why, the values of Portugal and Spain are not the same at the following figures and in fact, for some values, the difference is quite high. The range of the external costs of SO_2 , NO_X and PM_{10} are smaller for Portugal than for Spain because of the high variety in the previously mentioned variables used in the study and are between approximately €6,000 per ton and €30,000 per ton of pollutant in 2015 prices.

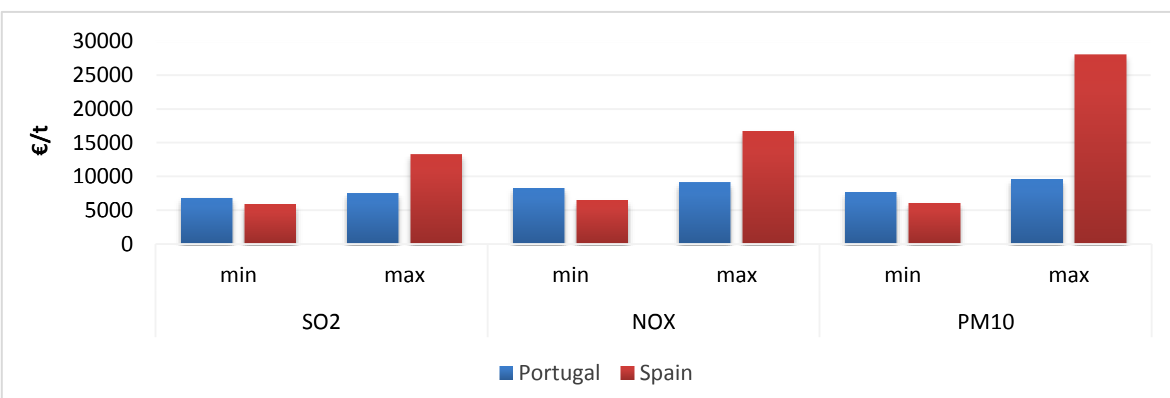

FIGURE 6.5: Damages by pollutant, years of life lost approach, 2015 €/t (1995 data) (Source: ExternE)

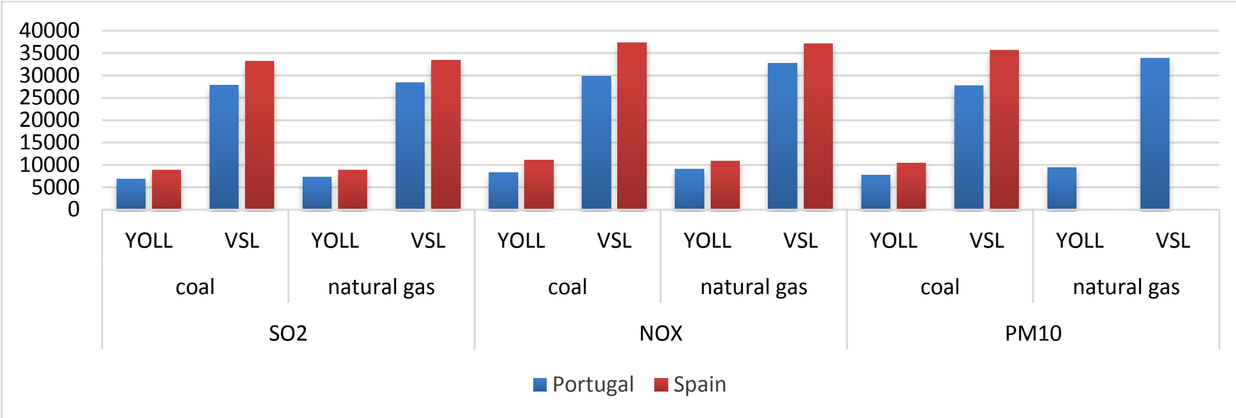

FIGURE 6.6: Damages by pollutant and by technology, YOLL and VSL approaches, 2015 €/t (1995 data) (Source: ExternE)[16]

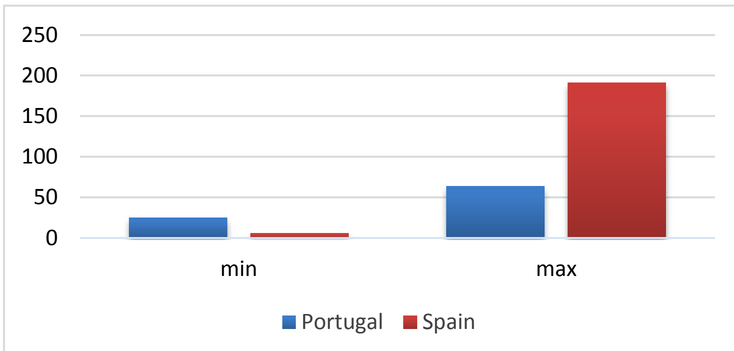

FIGURE 6.7: Damages by CO_2, years of life lost approach, 2015 €/t (1995 data) (Source: ExternE)

ExternE project results and its methodology have inspired many studies and created different models and tools which then found various practices. EcoSenseWeb, a paid model to calculate location specific marginal external cost of a facility such as a power plant and EcoSenseLE, a free simplified online tool to estimate the same costs, are the main ones developed within the project (ExternE, 2014). Although these two tools provide the marginal values needed for this study, in practice as a paid model, EcoSenseWeb is beyond my reach and EcoSenseLE gives only rough estimates for 2010 and the parameters that it uses are not reachable. In addition to that, National Implementation Reports of ExternE use the data from 1995 for Portugal and Spain, which does not have enough connection with the characteristics of the recent years. For instance, new installments of thermal plants and decomposition of some old ones have changed the intensity of the emissions in different locations in the last 20 years. Also, exposed population, environmental and human vulnerability to the emissions

[16] Damage cost of PM10 is not available in the report.

have not stayed constant. New trends and crucial changes in the electricity sector in the last 20 years led to extent the search to find more sensible marginal external values for Iberian Peninsula.

Another very relevant and more recent study conducted by IMF researchers, “Getting Energy Prices Right”, develops a practical methodology to set efficient set of energy taxes and quantifies energy externalities for 156 countries (IMF, 2015). Similarly, they follow a bottom-up approach and define the marginal values. For the damage value of CO_2, they use the value calculated by the US Interagency Working Group which is named as “social cost of carbon”. Moreover, by using location of plants, their corresponding estimated exposed populations are defined, health effects are monetized according to the various studies analyzed in OECD (2012) and finally by using country specific emission rates, damage is calculated per unit of energy content or fuel consumption.

Main variables that they used are

- Deaths per ton of fuel by SO_2, NO_X and $PM_{2.5}$ emissions
- Exposed population above the age of 25
- Mortality value taken as OECD average
- Social cost of carbon (US IAWG, 2015)
- Income data (GDP per capita (PPP)) (The World Bank, 2016; IMF, 2016)
- Income elasticity (OECD, 2012)
- Emission factors of coal and natural gas in power generation

The final results of IMF report are the damages per ton of emission of CO_2, SO_2, NO_X and $PM_{2.5,}$ and damages per energy content of the fuel input, using appropriate emissions factors. Country-specific emissions factors for each pollutant for coal and natural gas are taken from The Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) Model[17], in which the emissions factors are reported in kilotons of pollutant per petajoule (heat content). Types of coal vary significantly across countries as well as the emission control technologies which have an important effect on emission rates of each pollutant. The model takes these differences into consideration in order to calculate country specific damage per unit of fuel.

[17] See http://gains.iiasa.ac.at/models/index.html for further information on GAINS Model.

Based on the report published by US Interagency Working Group on Social Cost of Carbon in 2013, a value of $35 per ton of CO_2 with a discount rate of 3% is used in IMF study for illustrative purposes. Keeping in mind that damage cost of CO_2 emissions should have a single global value, value calculated by US IAWG can be used as social cost of carbon in the EU, as well. In the study, damage cost of CO_2 emissions is taken from the updated US IAWG report (2015) and their central value, 3% discount rate, is chosen: €37 per metric ton of CO_2 for emissions in the year 2015. For the damage cost of SO_2, NO_X and $PM_{2.5}$, same study takes the mortality value accepted by OECD for the year 2005, $3 million. Country specific mortality values are then calculated by rating the OECD mortality value by the ratio of the country to the OECD GDP per capita value with a power of income elasticity to reflect the percentage change in the mortality value per 1% change in real capita income and updated to 2015 for inflation (using the average consumer price index for the OECD). This value corresponds to $4.09 million for Spain, and $3.57 million for Portugal in 2015. The same data sources are used to update the values of the IMF report. In order to calculate 2015 mortality values, purchasing power parity based GDP per capita of Spain, Portugal and average for OECD members are updated by the data published in World Bank and IMF values. Finally, by weighting according to exposed population in Spain and Portugal, a single value for each pollutant is computed for mortality value of $3 million in 2005 and €1 million[18] in 2015.

Emission factors: Emission factors are the last component to calculate emission damage per technology and having a sensible average rate is crucial for the study. Although different reliable and widely credible sources are available, they are not all suitable. For instance, E-PRTR, as a detailed database, contains the yearly emissions of the pollutants for each facility registered, yet the data are only until 2013 and does not capture all emissions (European Commission, 2015). Apart from it, IED and Medium Combustion Plants Directives set limits for the power plants over 1 MWth rated thermal input and these values can be found in the regulation. Nevertheless, neither E-PRTR yearly emissions nor upper limits of emissions set by regulations provide sensible values of tons of emissions per energy generated/fuel input. CO_2 emission rates were already available in Endesa database for each plant in Iberian Peninsula. Also, IMF report provides country-level average emission rate across all existing plants with and without emissions control technologies. So, an average of CO_2 emission rate (weighted by the units' maximum output) for coal and CCGT power plants is chosen and the emission rates for the rest of the pollutants (SO_2, NO_X, $PM_{2.5}$) are taken from the IMF report (TABLE 6.5).

[18] Another commonly used mortality value.

Finally, by using the adjusted emission damage cost (€ per ton) and emission factors, emission damage costs of pollutants are computed separately in 2015 €, as € per GJ (see TABLE 6.6 and TABLE 6.7).

TABLE 6.5: Emission factors

Pollutants	Coal Power Plants (kt/PJ)	CCGT Power Plants (kt/PJ)
CO_2	101	37
SO_2	0.216	0.001
NO_X	2.212	0.032
$PM_{2.5}$	0.009	0.000

TABLE 6.6: Emission damage cost of pollutants in 2015 € per ton.

Pollutants	Coal Power Plants (€/t)		CCGT Power Plants (€/t)	
	Mortality value = $3 million	Mortality value = €1 million	Mortality value = $3 million	Mortality value = €1 million
CO_2	37	37	37	37
SO_2	15,458	4,198	16,983	4,612
NO_X	12,041	3,270	12,931	3,460
$PM_{2.5}$	18,934	5,142	20,931	5,684

TABLE 6.7: Emission damage cost of pollutants in 2015 € per GJ.

Pollutants	Coal Power Plants (€/GJ)		CCGT Power Plants (€/GJ)	
	Mortality value = $3 million	Mortality value = €1 million	Mortality value = $3 million	Mortality value = €1 million
CO_2	3.74	3.74	1.37	1.37
SO_2	3.44	0.93	0.02	0.00
NO_X	2.61	0.71	0.41	0.11
$PM_{2.5}$	0.19	0.05	0.00	0.00

6.1.4. Value of Loss Load (VOLL)

In this study, adequacy effect of wind and solar PV installations is monetized by the value of lost load (VOLL) and calculated for only Spanish Peninsula because of data availability. Assigning a value for loss load has been always tricky and a wide range of values can be found in literature depending on the methodology and the country. Most common approaches in the literature to calculate the value are surveys to state, case studies, and macroeconomic analysis (production function). At the surveys, willingness-to-accept (WTA) payment for an outage and willingness-to-pay (WTP) to avoid an outage is asked.

TABLE.6.8: Results of some of the VOLL studies

Source	Location	Method (Unit)	VOLL
(London Economics, 2013)	UK	WTA for domestic users (2013 £/MWh)	11,145
		WTA for medium sized business (2013 £/MWh)	2,766
		WTA weighted average (2013 £/MWh)	16,940
(London Economics International LLC, 2013)	ERCOT	Macroeconomic analysis (2011 $/MWh)	5,645-6,468
(Linares & Rey, 2013)	Spain	Macroeconomic analysis (2008 €/MWh)	6,350
(Leahy & Tol, 2011)	Ireland	Macroeconomic analysis (2007 €/MWh)	12,900

In order to have a better emphasis on social and indirect economic impact, customer surveys give more sensible results compared to macroeconomic analysis (Linares & Rey, 2013). That is why, the most recent data which follows this methodology, London Economics study for adequacy calculations is chosen in this study and the corresponding VOLL for 2015 is calculated as €23,700 per MWh.

6.1.5. Taxes

6.1.5.1. Fuel and Generation Tax, Electricity Network Tariff

Fuel tax for coal and natural gas is 0.65 Euros per gigajoule[19] of the fuel input, generation tax is 7% on all generation units, and Electricity Network Tariff is €0.5 per MWH of generated energy in Iberian Peninsula. (Ley 15/2012 & Ley 16/2013; (ACER, 2014)).

Although Portuguese tax structure is different from the Spanish one, it shows similar taxation levels. So, taxation structure of Iberian Peninsula can be assumed as that of Spain.

[19] Fuel tax of 0.65 €/GJ is defined under Spanish regulation.

6.2. Implementation to the Iberian Market

After gathering the data to be used for Iberian Market, previously described methodology is followed. First, approximate operating costs of coal and CCGT power plants are calculated to define the hourly operating cost ranges which capture the marginal technology of each hour by using the net market prices. Secondly, by total hourly production data of wind and solar PV, their corresponding production profiles for 1 MW of capacity are extracted. Thereby, hourly energy replacement amount by RES and the conventional unit which decreases its output by that amount are identified. Then, avoided operating and emissions costs are calculated in yearly and per MWh of energy generated by RES basis. After the computation of yearly adequacy gain, costs and benefits are summarized, and finally it ends with robustness analysis.

6.2.1. Operating cost

Operating cost or, in other words, variable energy generation cost for fossil fuel power plants in Iberian Peninsula is formed as:

$$OC_{t,d}{}^{20} = Fuel\ Cost_{t,d} + Variable\ O\&M\ Costs_t + CO2\ Cost_{d,t} + Taxes_t$$

where t is the fossil fuel technology coal or CCGT, and d is day. While fuel cost and CO_2 costs change through time[21], variable 0&M costs are taken as constant in this study.

As a first step of calculating operating cost, heat rates for coal and CCGT power plants are calculated. Although heat rates of each power plant are available, their hourly production level is unknown. By assuming an average of 80% electricity generation of the maximum net power output for both coal and CCGT power plants, approximate constant values for the two technologies are found by the corresponding formula.

[20] Although access tariff, start-up cost, shut-down cost are internalized in operating costs, they are not included to the calculations.
[21]API2 Index is quoted on a weekly basis while UK Natural Gas Futures and EU ETS are daily prices; yet not available on weekends and public holidays. So, it is assumed that fuel and carbon prices on these days are equal to their last available market prices.

$$Heat\ rate_t\ \left[\frac{th^{22}}{MWhe}\right] = \frac{\sum_{p=1}^{P}\left(\frac{\beta_{t,p}\left[\frac{th}{h}\right] + \alpha_{t,p}\ \left[\frac{th}{kWhe}\right] \times 0.8 \times \overline{q_{t,p}}\ [kWe]}{\overline{q_p}\ [kWe]}\right)}{\sum_{p=1}^{P}\overline{q_{t,p}}\ [kWe]} \quad for\ t = COAL, CCGT$$

Where β is the fixed term, α is the variable term, $\overline{q}$ is the maximum power level, and p is the power plant.

In general, fuel cost is calculated as $Fuel\ Cost = \ (Fuel\ Price + Fuel\ Tax) \times Heat\ Rate$ where fuel tax is 0.65 €/GJ in Spain.

Weekly fuel cost of coal and daily fuel cost of CCGT power plants are:

$$Fuel\ Cost_{COAL,w}\ \left[\frac{€}{MWh}\right] = \left[\frac{\left(API2\ Index_w\left[\frac{\$}{t}\right]/Exchange\ Rate\ _d\left[\frac{\$}{€}\right]\right) + Logistics\ Cost\ \left[\frac{€}{t}\right]^{23}}{Net\ Calorific\ Value\ \left[\frac{th}{t}\right]^{24}} + Fuel\ Tax\ \left[\frac{€}{GJ}.\frac{GJ}{th}\right]\right] \times Heat\ Rate_{COAL}\ \left[\frac{th}{MWhe}\right]$$

$$Fuel\ Cost_{CCGT,d}\left[\frac{€}{MWh}\right] = \left[\left(UK\ Natural\ Gas\ Futures_d\left[\frac{\$}{MMBtu}\right]/Exchange\ Rate_d\ \left[\frac{\$}{€}\right]\right)\cdot\left[\frac{MMBtu}{th}\right] + Fuel\ Tax\left[\frac{€}{GJ}.\frac{GJ}{th}\right]\right] \times Heat\ Rate_{GAS}\left[\frac{th}{MWhe}\right]$$

where logistics cost is from \$2 to \$18 per ton of coal input.

After fuel cost, CO_2 cost is calculated by the corresponding formula including CO_2 emission rates of each technology.

$$CO2\ cost_{d,t}\left[\frac{€}{MWh}\right] = EU\ ETS\ Price_d\ \left[\frac{€}{t}\right] \times CO2\ Emission\ Rate_t{}^{25}\ \left[\frac{t}{MWh}\right] \quad for\ t = COAL, CCGT$$

[22] th (thermia) = 1 million calories.
[23] Fuel cost is calculated with and without logistics cost ($2 and $18 per ton of coal).
[24] API2 specification: 6000 th/t, (Argus, 2016)
[25] Single values for coal and CCGT power plants are weighted average value by their maximum output.

Finally, operating cost of coal and CCGT power plants are computed by the following formula.

$$(Fuel\ Cost + Variable\ O\&M\ Costs + CO2\ Cost) \times (1 + Generation\ Tax)$$

TABLE 6.9: Values of cost components (in 2015 prices)

Cost Components	unit	Coal Power Plants	CCGT Power Plants
Variable O&M Costs	€/MWh	2	1
Logistics Cost	$/t	2-18	
Fuel Tax	€/GJ	0.65	0,65
Electricity Network Tariff	€/MWh	0.5	0.5
Generation Tax	%	7%	7%
Heat Rate Ratio	%	80%	80%
Heat Rate*	th/kWh	2.40	1.57
CO_2 Emission Rate	t/MWh	1.01	0.37

*Net values.

6.2.1.1. Identification of the Marginal Technology

In Iberian Power System, coal and CCGT power plants are mostly marginal, that is, incremental capacity increase on wind and solar PV technologies displace these technologies. The most expensive unit at the dispatch is CCGTs and it is followed by coal power plants. Having the rest of the available technologies in Iberian Peninsula not responding to the changes in RES generation, they are gathered in one group and left out of focus on cost and benefit analysis so three hourly operating cost ranges are set: one for CCGT, for coal and for other technologies. These cost ranges are defined by two thresholds. While the higher threshold distinguishes the marginal technology of that hour as either coal or CCGT, lower one sets the lower boundary between coal and cheaper technologies in the dispatch.

In order to define a threshold between coal and CCGT power plants, two approaches have followed:

(1) threshold is set in between the operating cost of coal and CCGT power plants by the formula shown below and the level with the best capture rate is chosen by trial and error;

$$x\% \cdot OC_{CCGT,d} + (100-x)\% \cdot OC_{COAL,d}{}^{26} \qquad\qquad for\ x = [0,100]$$

(2) by adding the maximum logistics costs for coal power plants, maximum operating cost of coal power plants is calculated and set as the threshold.

$$Fuel\ Cost_{COAL,d}\ \left[\frac{€}{MWh}\right] = \left[\frac{\left(API2\ Index_d\left[\frac{\$}{t}\right]/Exchange\ Rate\ _d\left[\frac{\$}{€}\right]\right) + \boldsymbol{Maximum\ Logistics\ Cost}\left[\frac{€}{t}\right]}{Net\ Calorific\ Value\left[\frac{th}{t}\right]^{27}} + Fuel\ Tax\ \left[\frac{€}{GJ}.\frac{GJ}{th}\right]\right] \times Heat\ Rate_{COAL}\ \left[\frac{th}{MWhe}\right]$$

These two ways define hourly boundary between the operating costs of coal and CCGT power plants. The lower operating cost bound of coal power plants which is the threshold between coal and the rest of the technologies is assumed to correspond to the minimum operating cost of coal technology and follow the trend of the operating cost of coal technology previously calculated. By trial and error, different ratios are tried and the most sensitive value is chosen.

$$y\% \cdot OC_{COAL,d}{}^{28} \qquad\qquad for\ y = [0,100]$$

Since the only time dependent cost components of operating cost that are included into the calculations are fuel cost and CO_2 prices, thresholds follow their trend and their mark-up is set by the rest of the components.

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[26] Logistics cost of coal is not added.
[27] API2 specification: 6000 th/t, (Argus, 2016)
[28] Logistics cost of coal is not added.

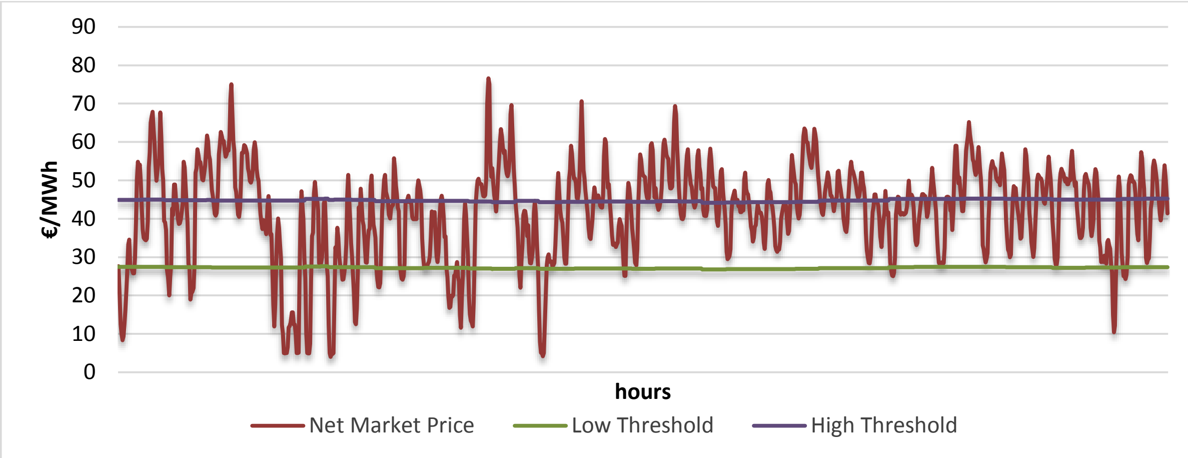


FIGURE 6.8: An example of thresholds and net market prices in the period between 15 February and 31 March, 2015

For instance, the hours when the net market price is (1) above "high threshold", CCGT power plants are marginal, (2) in between "low" and "high threshold", coal power plants are marginal, (3) below "low threshold" technologies out of the focus are marginal (FIGURE 6.8).

Setting the thresholds is the initial step but the crucial part of the identification is measuring the performance of the thresholds and deciding on the best one which has the highest capture rate. In order to measure the performance of the thresholds, hourly marginal unit information is necessary. However, by using market data, this information is quite cumbersome to obtain and not certain to be reliable. This problem led to hourly production data of coal and CCGT technologies to analyze the performance of the thresholds. First, hourly estimated average operating costs of coal and CCGT power plants are computed and "high threshold" is set as the average. It is seen that this threshold underestimates the hours when coal power plants are marginal, so its level increased until obtaining its best possible results: 20% of the average operating cost of coal and 80% of CCGT technologies. It is obvious that average operating cost of coal is underestimated by including fuel, variable O&M, carbon costs and taxes only and not considering logistics costs. Then the same threshold is also calculated by the maximum operating cost of coal approach which includes maximum logistics cost on operating cost of coal calculations and a significant improvement on the results throughout all the year is observed. For the "low threshold", different percentages of the average operating cost of coal have been tried and the best result is obtained by 70%. So, for the low threshold, 70% of the operating cost of coal without logistics cost is chosen while operating cost which includes the maximum logistics cost is chosen as the high threshold. An important remark is that start-up and shut-down costs, access tariffs for CCGTs are not added and full pass-through rate is assumed for carbon price and generation tax.

TABLE 6.10: Best results of both approaches with the best “low threshold”

Marginal technology	1st approach	**2nd approach**
	# of hours of marginal technology (%)	
CCGT	5702 (29.6%)	**5633 (30.3%)**
Coal	2589 (65.1%)	**2658 (64.3%)**
Others	469 (5.4%)	**469 (5.4%)**

6.2.2. Production Profiles of Wind and Solar PV

After identifying marginal units of every hour in Iberian Peninsula in 2015, hourly generation of wind and solar PV power plants need to be defined so that the avoided costs and environmental damages can be computed. For illustrative purposes, production profiles of wind and solar PV are obtained from the aggregate wind and solar PV production data for Spain in 2015 by adapting the capacity to 1 MW. Total wind production 18% higher than the solar PV production in 2015 and correspond to 2.087 and 1.770 GWh for 1 MW capacity, respectively. As it has been discussed in Chapter 4, wind generates electricity all day while solar PV is unavailable at nights. Moreover, production profile illustrations show that electricity generation by wind weakens during summer months and rises for solar PV. By looking at the profiles, it can be expected that although total savings of solar PV is lower, average savings per MWh produced is higher than wind.

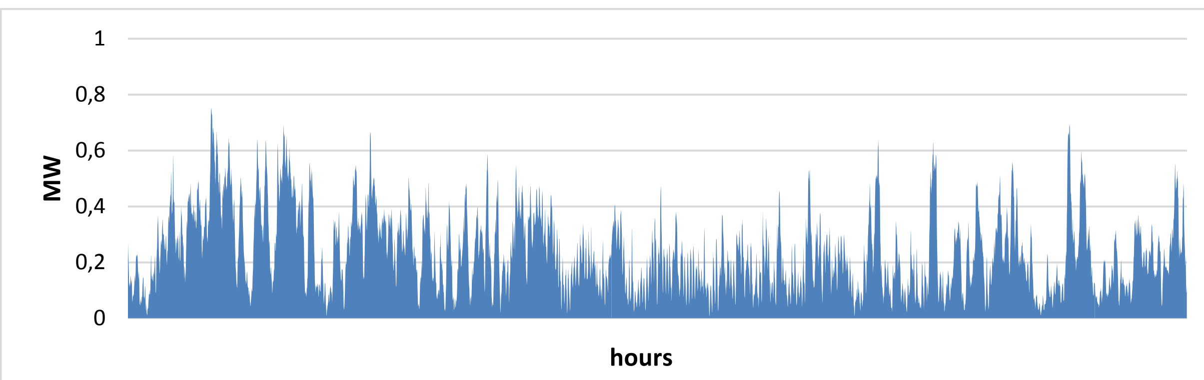


FIGURE 6.9: Wind production profile for 1 MW of capacity, adapted from total wind production data of Spain, for the year 2015.

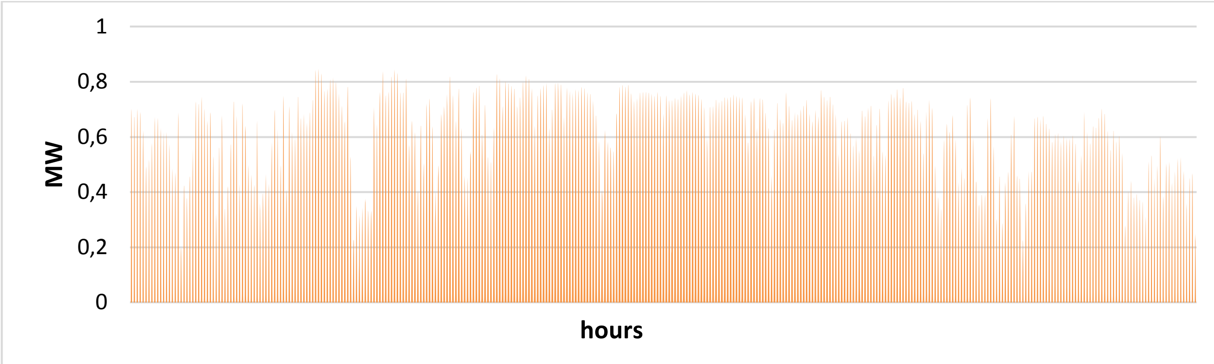


FIGURE 6.10: Solar PV production profile for 1 MW of capacity, adapted from total solar PV production data of Spain, for the year 2015.

6.2.3. Marginal Benefits and Costs

6.2.3.1. Avoided Emissions Costs

IMF results are updated to their 2015 values and adapted to the Iberian Peninsula as a single average value weighted by their corresponding exposed populations. Two different mortality values, initial value of IMF report as \$3 million in 2005, and €1 million in 2015[29] are used in damage cost calculations of SO_2, NO_X and $PM_{2.5}$. Moreover, damage cost of CO_2 emissions is taken as €37 per ton of pollutant. Initially, total avoided emissions are calculated in tons and then their damage is monetized by the values adapted from IMF study. Then, avoided emissions (AE) and avoided emissions cost (AEC) of the pollutants CO_2, SO_2, NO_X and $PM_{2.5}$ in EUR, and average avoided emissions costs ($AAEC$) of the pollutants (p) CO_2, SO_2, NO_X and $PM_{2.5}$ in EUR per MWh of energy produced by RES technologies (r) wind and solar PV are computed separately by the following formulas for the year 2015.

$$AE_{r,p}[t] = \sum_{h=1}^{8760}\sum_{t=1}^{T}\left(\alpha_{t,h}\cdot EF_{p,t}\left[\frac{t}{MWh}\right]\cdot q_{r,h}[MW]\right) \qquad for\ each\ \ r\ and\ p$$

$$where\ \alpha_{t,h} = \begin{cases} 1, if\ technology\ t\ (COAL, CCGT)\ is\ the\ marginal\ unit\ at\ hour\ h \\ 0, otherwise \end{cases}$$

$$AEC_{r,p}[€] = \ EC_p\left[\frac{€}{t}\right]TAE_{r,p}[t] \qquad for\ each\ \ r\ and\ p$$

---

[29] Value of life defined in Spanish regulation.

$$AEC_{r,p}\left[\frac{€}{MWh}\right] = \frac{AEC_{r,p}[€]}{\sum_{h=1}^{8760} q_{r,h}[MW]} \qquad for\ each\ r\ and\ p$$

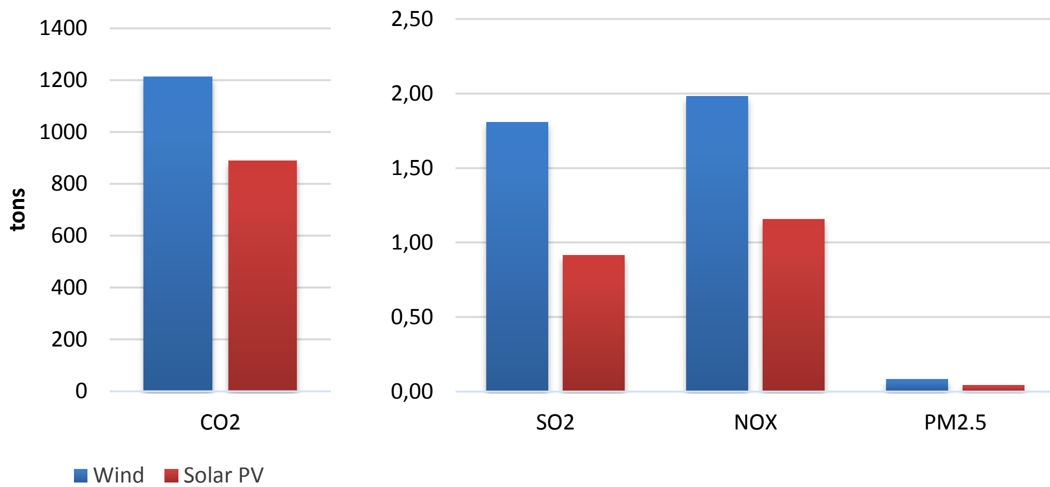


FIGURE 6.11: Total avoided emissions (tons), 2015

FIGURE 6.11 illustrates avoided emissions in tons as a result of power generation replacement by RES[30]. Since total wind power production by 1 MW of increase is 18% higher than solar PV, avoided emissions by wind technology is also higher overall. Moreover, the difference on the production profiles of the RES technologies have an impact on the difference and it is the reason of the variation on the difference among the pollutants. While the difference is the lowest for avoided CO_2 emissions (36% higher for wind than solar PV) and 72% higher NO_X emissions for wind than solar PV, avoided SO_2 and $PM_{2.5}$ emissions by wind generation increase is twice as high as by solar PV generation increase. Solar PV produces at the hours with high market prices and replaces the most expensive generating unit, CCGT. Despite high operating costs, CCGTs emit less than coal power plants, in fact, they emit almost zero SO_2 and $PM_{2.5}$ which accounts for the higher difference on avoided emissions of those pollutants. On the other hand, wind power is available during the whole day. Even though it fluctuates, its hourly average generation is steady compared to solar PV. That is why, wind replaces coal-fired power plants at the cheap hours and displaces more than 1200 tons of CO_2, 1.8 tons of SO2, 2 tons of NO_X and 80 kg of $PM_{2.5}$ in Iberian Peninsula in 2015.

[30] Emissions displacement performance of RES technologies is shown in Appendix A.

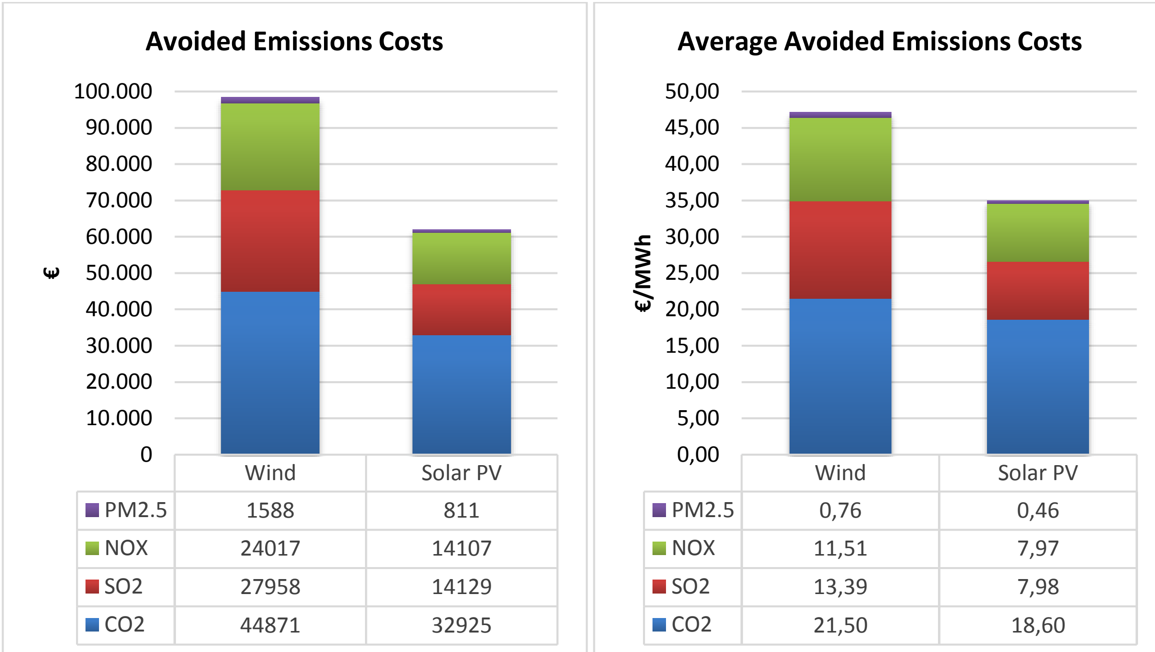


FIGURE 6.12: Total avoided emissions costs and average avoided emissions costs of pollutants CO_2, SO2, NO_X and $PM_{2.5}$ for 2015 (mortality value is \$3 million in 2005[31])

Avoided emissions in tons for each pollutant and RES technology provides necessary information on emission displacement performance of wind and solar PV power plants, yet, it lacks the information of damage caused by these harmful pollutants. By using damage cost data presented in TABLE 6.6 for each pollutant, avoided emissions cost in EUR and average avoided emissions cost in EUR per MWh of RES production are calculated (FIGURE 6.12). While savings by wind installation is approximately €100,000, it stays in €62,000 for solar PV in 2015. Breakdown of the aggregate damage costs show that most of the damage is caused by CO_2 and followed by SO_2. In addition to total avoided emissions costs, average values per MWh of RES production give additional information. Emission savings per MWh of wind and solar PV energy is €47 and €35, respectively. The prominent result of the comparison of the figures are the improvement of solar PV results with respect to wind due to lower total solar PV production than wind. However, solar PV is not as efficient as wind in terms of emission damage savings. While savings of CO_2 emission displacement are close, savings by SO_2, NO_X and $PM_{2.5}$ emission reduction are almost half of wind for solar PV. All in all, wind is more beneficial than solar PV in Iberian Peninsula because it replaces coal power plants more than solar PV.

[31] The results of €1 million mortality value in 2015 is discussed in the Section 6.2.3.4

6.2.3.2. Avoided Operating Cost

For the hours when the marginal technology is either coal or CCGT power plants, avoided operating cost is calculated by multiplying the expected renewable production with corresponding net market price of that hour, and aggregating these costs across all hours. In addition to the total avoided operating cost ($TAOC$), average avoided operating cost ($AAOC$) is calculated by dividing $TAOC$ by the sum of energy produced.

$$TAOC_r[€] = \sum_{t}^{T} \sum_{h=1}^{8760} \alpha_{t,h} NMP_h \left[\frac{€}{MWh}\right] q_{r,h}\,[MW] \qquad for\ r = wind\ and\ solar\ PV$$

$$AAOC_r\left[\frac{€}{MWh}\right] = \frac{\sum_t^T \sum_{h=1}^{8760} \alpha_{t,h} NMP_h \left[\frac{€}{MWh}\right] q_{r,h}\,[MW]}{\sum_{h=1}^{8760} q_{r,h}[MW]} \qquad for\ r = wind\ and\ solar\ PV$$

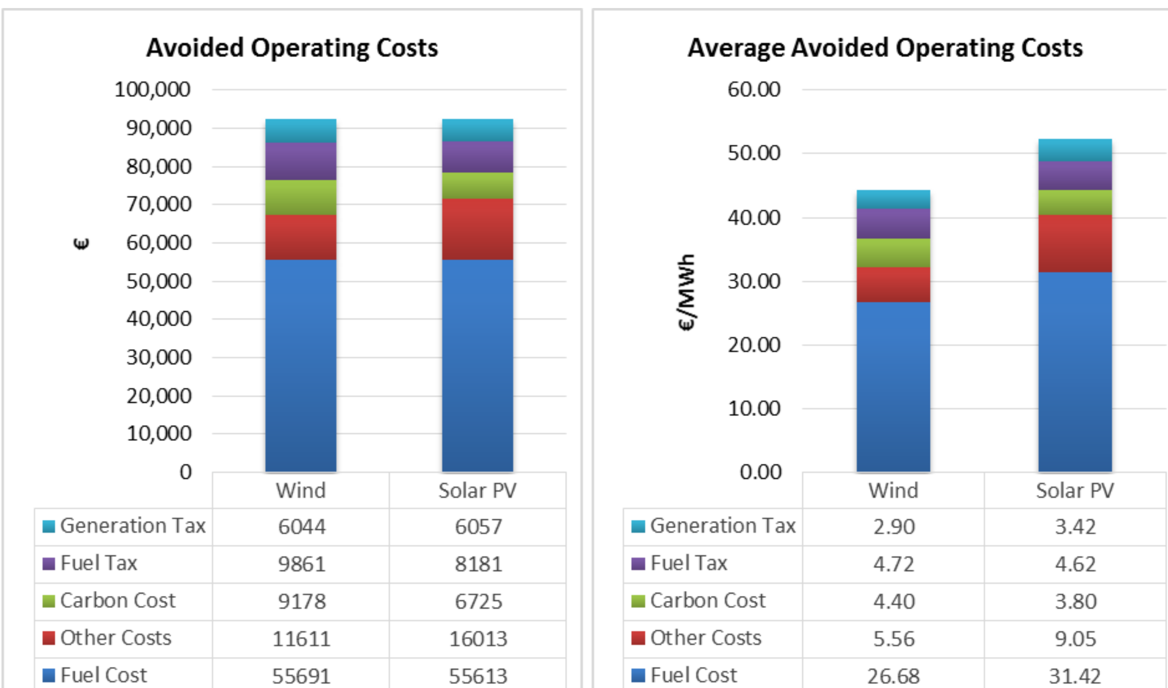
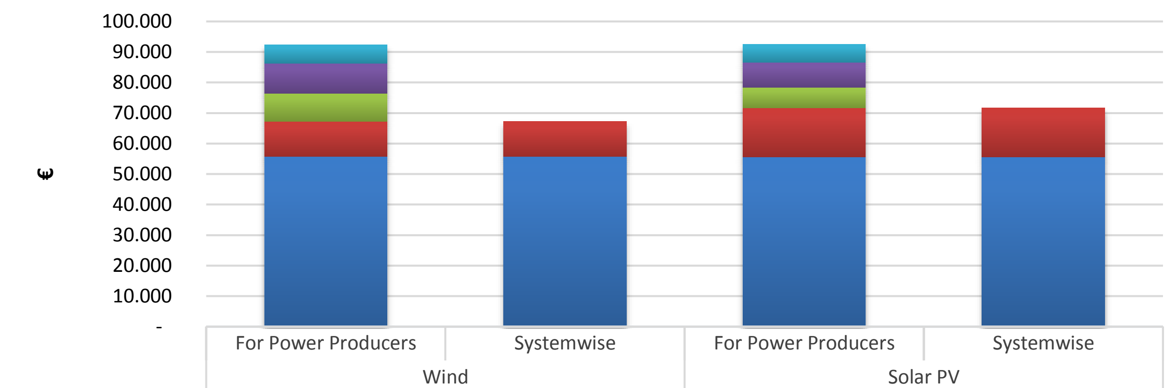


FIGURE 6.13: Avoided Operating Costs and Average Avoided Operating Costs of pollutants CO_2, SO_2, NO_X and $PM_{2.5}$ in 2015.

As it can be seen in FIGURE 6.13, while total avoided operating costs of incremental wind and solar PV installations are approximately the same, average avoided operating cost per MWh of RES output vary. Since solar PV power is available mostly at the most expensive market price hours of the day, it replaces CCGT power plants which are the last and the most expensive generating unit at the dispatch. This puts the difference on the efficiency of RES units per MWh of output. Still, when we look at the total saving, higher total output by wind balances this situation in its aggregate amount. What is more, wind capacity increase saves more of fuel and carbon tax and solar PV saves more of other costs which includes access tariff for gas. So it is clear that wind technology helps to reduce emissions while solar PV is more effective on decreasing the total operating cost per MWh of generation. In total, average avoided operating cost of wind is €44.26 and that of solar PV is €52.31 per MWh of output.



	Wind – For Power Producers	Wind – Systemwise	Solar PV – For Power Producers	Solar PV – Systemwise
Generation Tax	6.044		6.057	
Fuel Tax	9.861		8.181	
Carbon Cost	9.178		6.725	
Other Costs	11.611	11.611	16.013	16.013
Fuel Cost	55.691	55.691	55.613	55.613

FIGURE 6.14: Avoided Operating Costs with and without taxes & carbon cost in 2015.

Reminding the discussion at the Section 5.1.2, more relevant operating cost in order to evaluate incentives and support mechanisms of RES excludes taxes and cost internalization of carbon price. That is why, one needs to take out these costs from the total operating cost and reach the real operating cost which the system faces. These values for wind and solar PV are €67,302 and € 71,627 in the given order.

6.2.3.3. Adequacy Gain

As it is defined in the Chapter 4 and 5, system generation adequacy level is the margin between net demand and the sum of available generation in the region and available interconnection capacity and can be calculated by the following formula developed for this study:

$$Total\ adequacy\ gain = \sum_{h=1}^{8760}\left[f_h\left(AM_{old,r}\right) - f_h\left(AM_{new,r}\right)\right] \qquad for\ r = wind\ or\ solar\ PV$$

Since the function *f(x)* is defined as exponential, hourly demand and available generation data are needed for sensible analysis and unfortunately, this data is not available for Portugal. That is why, possible total adequacy gain is calculated only for Spanish part of Iberian Peninsula.

Hourly net demand and total available power generation capacity are:

$$\begin{aligned} Net\ demand_h = \ & Demand_h - (Wind_h + Solar\ PV_h + Solar\ Thermal_h + Cogeneration_h + Biomass_h) \\ & + Net\ Import_h\ (Import_h - Export_h) \qquad for\ h = [1, 8760] \end{aligned}$$

$$\begin{aligned} & Total\ Available\ Power\ Generation\ Capacity\ (TAPGC)_h \\ & \quad = Total\ Available\ Thermal\ Capacity\ (Nuclear + Coal + \ Natural\ gas)_h \\ & \quad + \ Total\ Available\ Hydro\ Capacity\ (Hydro + Pumping)_h \qquad for\ h = [1, 8760] \end{aligned}$$

Spanish Peninsula is connected to two countries, France and Portugal with 2800 and 3000 MW import capacity, respectively (REE, 2012). By following a conservative approach, available interconnections between these countries are taken as 85% of total import capacity. As the country is connected to the rest of Europe via France interconnection lines, import availability[32] via this interconnection can be taken independently from available generation capacity of France:

$$Minimum\ available\ import\ capacity\ from\ France\ to\ Spain = \ Import\ Capacity \cdot 90\%$$

However, this is not the case for the Portugal-Spain interconnection. Portugal is a small country with a lower total installed capacity with respect to Spain. So, two factors need to be considered while calculating available interconnection capacity between Portugal and Spain. Even if there is enough available transmission capacity at the direction from Portugal to Spain, if there is not enough available generation capacity to generate that power, the available power to transfer will be the available generation capacity, not the available transmission capacity. Because of that, while calculating available interconnection capacity for Portugal, the country's available margin with respect to peak demand is also considered and the minimum of those is chosen as the available capacity. Because of data unavailability, this part of the computations is done in yearly average basis and following formula is used.

[32] 90% of the line import capacity for both connections.

$$Minimum\ available\ import\ capacity\ from\ Portugal\ to\ Spain =$$
$$\min\left[\left(\sum_t^T\left(Installed\ Conventional\ Generation\ Capacity_t{}^{33} \times EFOR_t\right) - Maximum\ Instantaneous\ Demand\right);\ \left(Import\ Capacity \cdot 90\%\right)\right]$$

where t is conventional technologies and $EFOR$ is equivalent forced outage rate.

Total hourly available power generation capacity, import capacity, demand and net demand of Spain for 2015 are shown in the FIGURE 6.15.

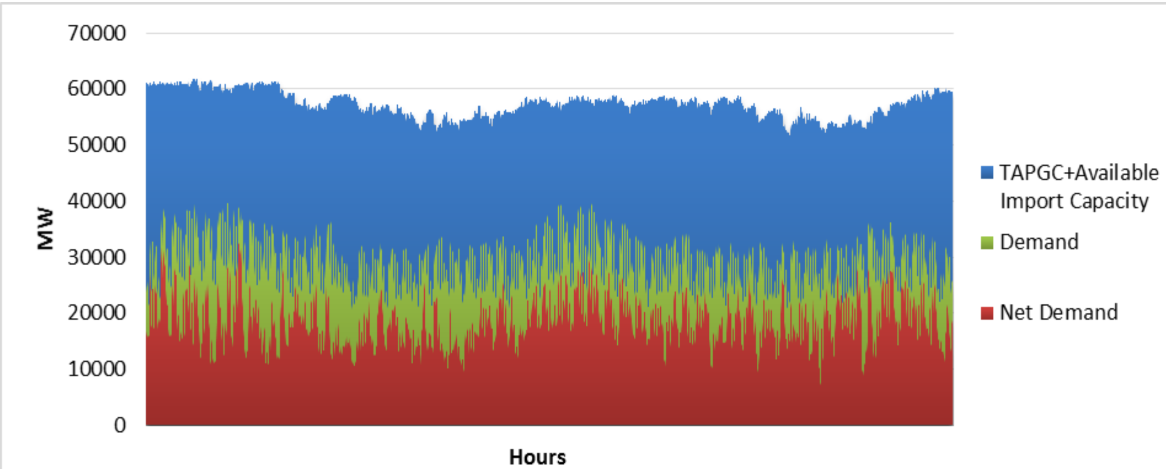


FIGURE 6.15: Total hourly available power generation capacity, import capacity, demand and net demand of Spain for 2015

Finally, hourly adequacy margin is calculated by the formula below.

$$Adequacy\ Margin_h = \frac{TAPGC_h - Net\ Demand_h + Minimum\ total\ available\ import\ capacity}{TAPGC_h + Minimum\ total\ available\ import\ capacity}$$

where minimum total available capacity is the total available import capacity of Portugal-Spain and France-Spain interconnections.

[33] Conventional Generation includes nuclear, coal, natural gas, fuel-gas, hydro and pumping power plants.

Assuming a safe ratio of 10% (margin over available capacity and imports) and corresponding value equals to 0.01% of VOLL, adequacy function is estimated as an exponential function and adequacy for any margin percentile x is calculated by the formula below.

$$Adequacy\ Cost_h \left[\frac{€}{MWh}\right] = VOLL \left[\frac{€}{MWh}\right] \cdot e^{\left(\frac{\ln(0.0001)}{10\%} \cdot AM_h\right)},$$
$$for\ every\ hour\ h = [1{,}8760]\ and\ AM = [0\%, 100\%]$$

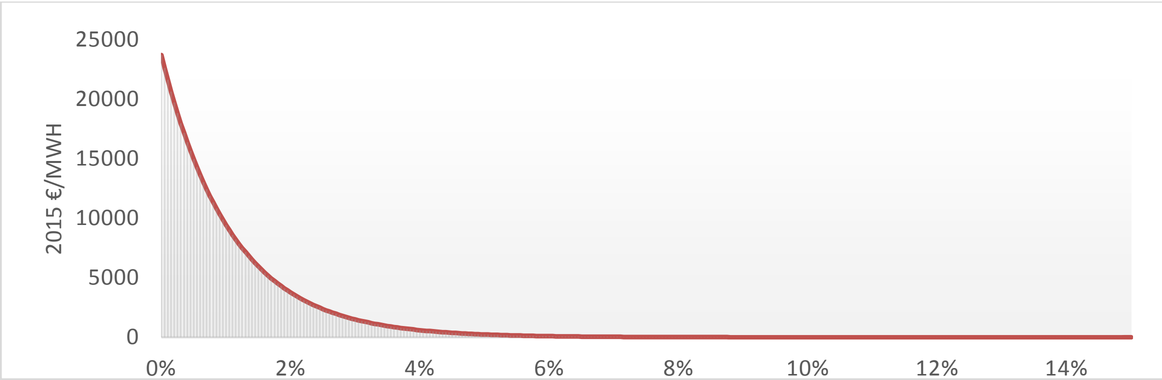


FIGURE 6.16: Adequacy function for VOLL of 2015 €23,700 per MWh.

Finally, adequacy savings can be reached as the difference between adequacy cost without incremental wind and solar PV investments and adequacy cost with incremental wind and solar PV investments. The savings are calculated separately for wind and solar PV. Adequacy savings by 1 MW of wind and solar PV investments are € $1.08*10^{-16}$ and € $1.62*10^{-17}$, respectively. As expected, values for Spain stay very low for 2015 but an important result of this analysis is 1 MW of wind investment gives 10 times more savings than 1 MW of solar PV investment as a result of lower capacity factor of solar energy than wind in Spain.

6.2.3.4. Net Costs

Net effect of marginal returns on RES investment is computed with LCOEs adapted to the study for the year 2015. This illustrative data is €54 per MWh for wind and almost €100 per MWh for solar PV technology. Benefits are the sum of avoided emissions cost, avoided operating cost and adequacy gain, and net cost is the LCOE which includes RES installment and operating costs. The total net cost (TNC) is the difference between the technology cost and total benefit, and average net cost (ANC) is found by dividing TNC into total output of wind or solar PV.

$$TNC_r[€] = LCOE_r\left[\frac{€}{MWh}\right]\sum_{h=1}^{8760} q_{r,h}\,[MW] - \left(\sum_{p}^{P} AEC_{r,p}\,[€] + TAOC_r[€] + AG_r[€]\right) \qquad for\ r = wind\ and\ solar\ PV$$

$$ANC_r\left[\frac{€}{MWh}\right] = LCOE_r\left[\frac{€}{MWh}\right] - \frac{\left(\sum_p^P AEC_{r,p}[€] + TAOC_r[€] + AG_r[€]\right)}{\sum_{h=1}^{8760} q_{r,h}\,[MW]} \qquad for\ r = wind\ and\ solar\ PV$$

Since adequacy gain is computed only for Spain and the value reached stays very low (less than 10^{-5}), net cost calculations do not include adequacy gain. Even if it was included, aggregate results would not be affected by its addition. The results are shown in the following figures.

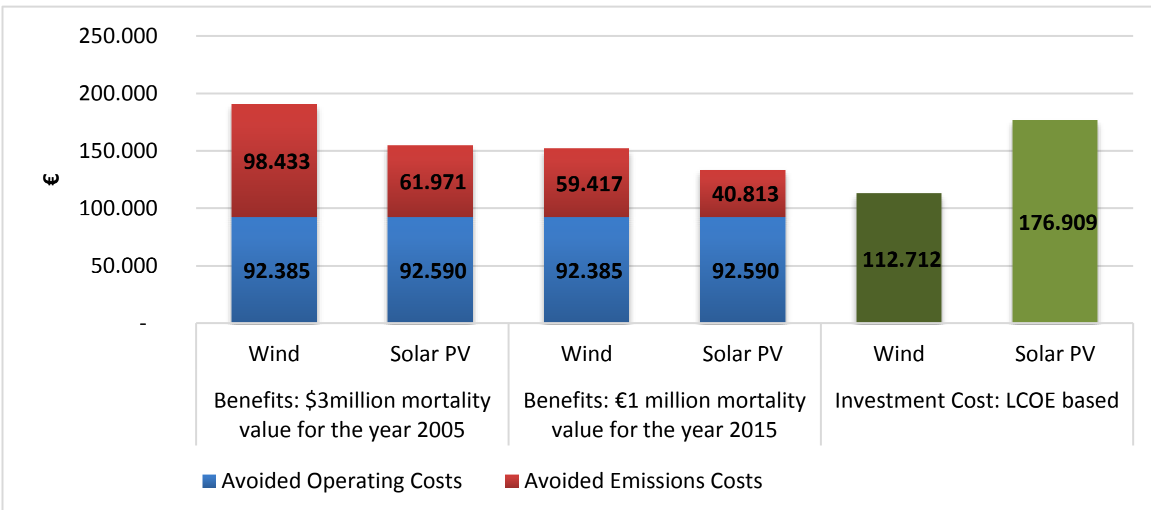


FIGURE 6.17: Total costs and benefits comparison for wind and solar PV, different mortality value for the year 2005, 2015 €-year. (Operating cost includes taxes and carbon cost.)

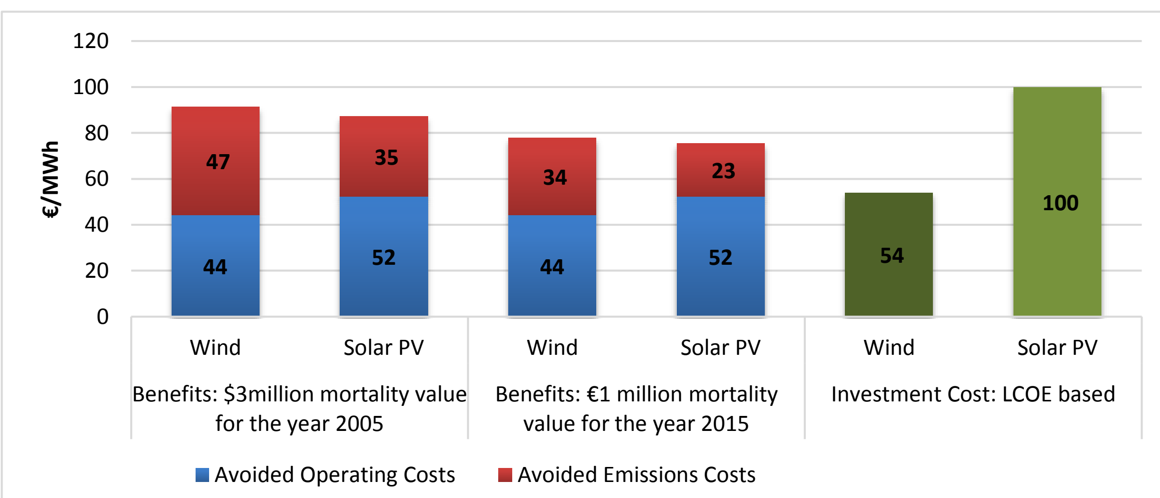


FIGURE 6.18: Average costs and benefits comparison for wind and solar PV, different mortality value for the year 2005, 2015 €/MWh. (Operating cost includes taxes and carbon cost.)

When the benefits and costs are compared, the prominent result is the comparative advantage of wind over solar PV in terms of both benefits and investment cost. Even if mortality value is taken as €1 million, net cost of incremental wind investment is negative. However, cost of solar PV investment is much higher than wind. What is more, monetized benefits of solar PV investment lower than wind. In total, net cost of solar PV stays positive and takes the values €22,348 and €43,506 for mortality values $3 million and €1 million. When mortality value is $3 million, net cost of investing to wind power plant is -€37/MWh and to solar PV power plant €13/MWh of output (-€24/MWh, €25/MWh in the case of €1 million mortality value) (FIGURE 6.17 and FIGURE 6.18).

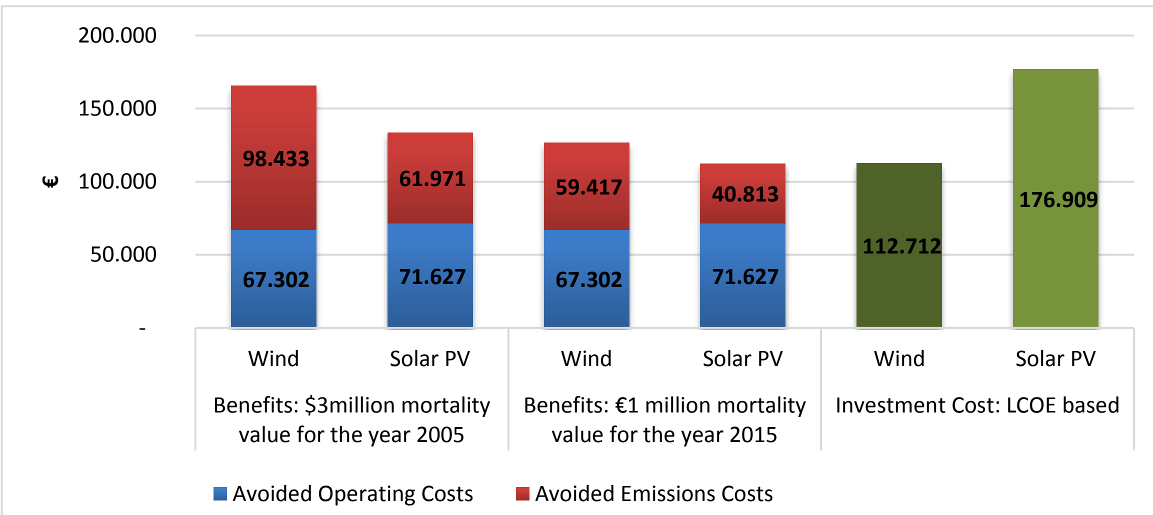


FIGURE 6.19: Total costs and benefits comparison for wind and solar PV, different mortality value for the year 2005, 2015 €-year. (Operating cost does not include taxes and carbon costs.)

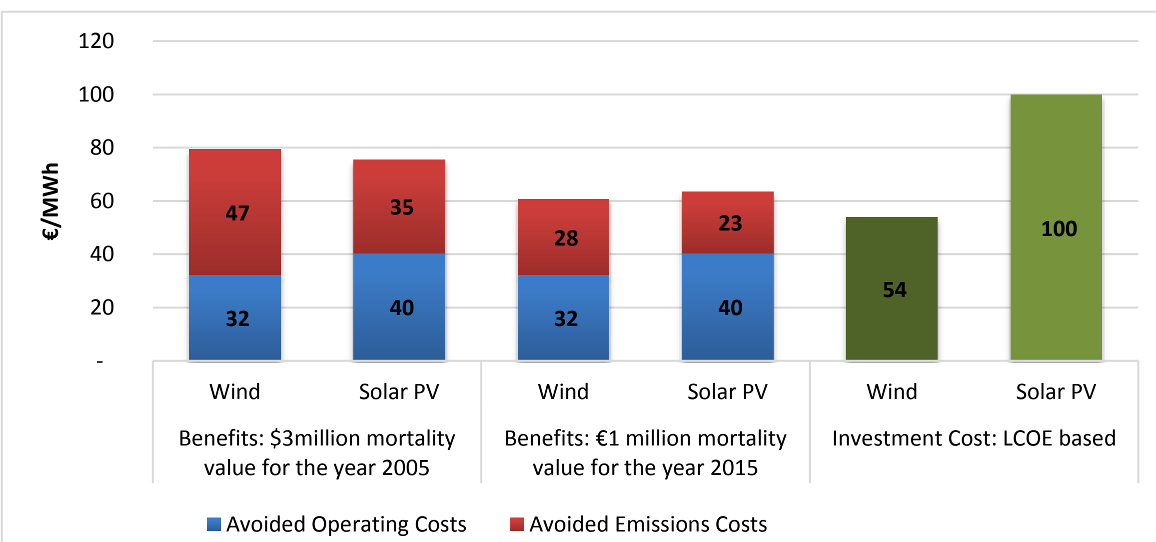


FIGURE 6.20: Average costs and benefits comparison for wind and solar PV, different mortality value for the year 2005, 2015 €/MWh. (Operating cost does not include taxes and carbon costs.)

In the case of updated operating costs to their real values by excluding taxes and carbon costs, the net costs of wind and solar PV investments decrease but wind keeps its negative value in both of the mortality values. When mortality value is $3 million, net cost of investing to wind power plant is -€25/MWh and to solar PV power plant €24/MWh of output (-€7/MWh, €36/MWh in the case of €1 million mortality value) (FIGURE 6.19 and FIGURE 6.20).

In addition to the net costs of marginal RES investments, another measure is developed and results are illustrated in FIGURE 6.21: net costs required to avoid a ton of emissions which can be named as average displacement cost (ADC) of emissions.

$$ADC_{r,p}\left[\frac{€}{t}\right] = \frac{LCOE_r\left[\frac{€}{MWh}\right]\sum_{h=1}^{H} q_{r,h}\,[MW] - (TAOC_r[€] + AG_r[€])}{\sum_p^P AE_{r,p}\,[t]}$$

$$for\ r = wind, solar\ PV\ and\ p = CO2, SO2, NOX, PM2.5$$

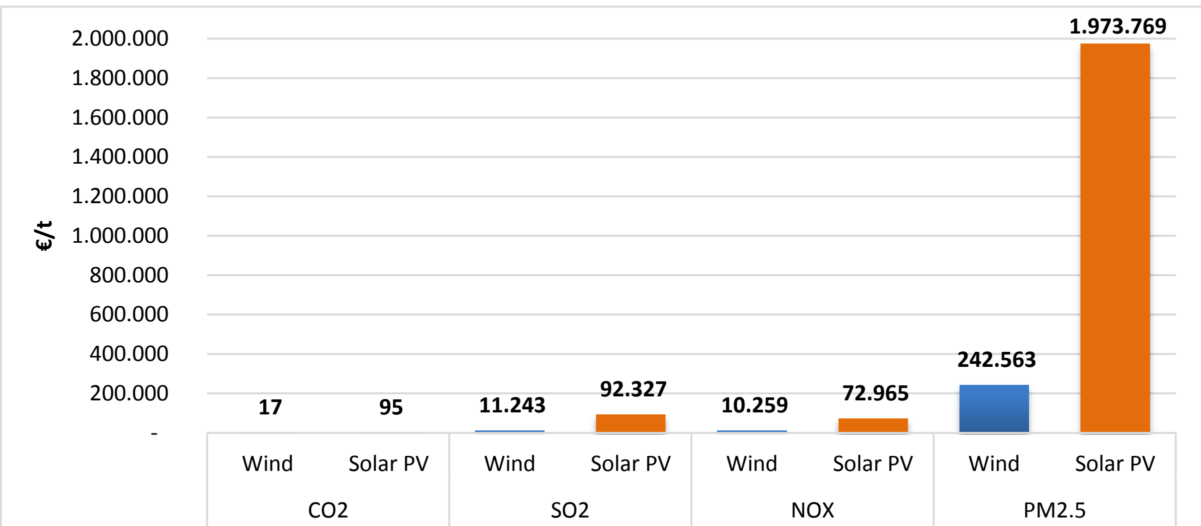


FIGURE 6.21: Average Displacement Costs of Emissions (€/t)

6.3. Robustness Analysis on the Thresholds

As shown at the previous sections, the methodology requires a number of assumptions, especially regarding quantitative values. That is why, it is important to analyze the sensitivity of the thresholds on the marginal unit identification and most importantly sensitivity of the results to the change of the threshold level.

Robustness of the identification methodology tested in two steps. First, the levels of "high" and "low thresholds" are readjusted and number of hours that coal, CCGT and other technologies being marginal generating units are recalculated. Then the effect of the level change of the threshold to the technologies which are identified as marginal is defined. Third, the change on the level of threshold to the monetized yearly benefits and costs in EUR are tested only for incremental wind capacity increase.

High threshold, 1st approach

TABLE 6.11: Sensitivity of the "high threshold", 1st approach, constant "low threshold"

Marginal technology	*x = %50*	*x = 60%*	*x= 70%*	*x = 80%*	*x = 90%*
CCGT	6311 (72.0%)	6119 (69.9%)	**5889** **(67.2%)**	5702 (65.1%)	5493 (62.7%)
Coal	1980 (22.6%)	2172 (24.8%)	**2402** **(27.4%)**	2589 (29.6%)	2798 (31.9%)

10% of change on the x value corresponds to approximately 2% change on the level of threshold at most. Shift on the threshold results in change around 200 hours of the total number of hours identified with their corresponding marginal technologies.

Operating cost changes depend on the "low threshold" since we assume that hourly market prices are the operating cost of the marginal units. So, at the hours when market price is above the low threshold, either coal or CCGT power plants are at the margin, and the operating cost of that hour is equal to the net market price of the same hour. Apart from that, total cost of investment and operating cost of RES depends on wind production levels. So, while total avoided operating cost, investment and operating cost of RES stay at same level, avoided emissions together with avoided emission cost vary by the change in the "high threshold". The results are shown in the TABLE 6.12.

TABLE 6.12: Change in costs and benefits in 2015 by "high threshold" shift. 1st approach, wind

Costs and Benefits			*x = %50*	*x = 60%*	*x= 70%*	*x = 80%*	*x = 90%*
Benefits	Avoided Emissions	***CO_2 (tons)***	1,112	1,143	1,181	1,211	1,245
		SO2 (tons)	1.46	1.57	1.69	1.81	1.92
		NOX (tons)	1.67	1.77	1.88	1.98	2.08
		$PM_{2.5}$ ***(tons)***	0.06	0.07	0.08	0.08	0.09
	Avoided Emission Cost (€)		85,301	89,406	94,333	98,330	102,690
	Avoided Operating Cost (€)		92,385	92,385	92,385	92,385	92,385
Total Benefits (€)			**177,686**	**181,790**	**186,717**	**190,715**	**195,075**
Total Costs (€)			**112,712**	**112,712**	**112,712**	**112,712**	**112,712**
Total Net Costs (€)			**-64,974**	**-69,078**	**-74,005**	**--78,003**	**--82,363**

Change in CO_2 emissions is around 3%; however, this is higher for the rest of the pollutants (around 6%). Also, while the change in avoided emissions cost and total benefits are approximately 2%, total net cost shows higher variation: 5-7%. Still, threshold level change results in lower impacts to the results.

High threshold, 2nd approach

TABLE 6.13: Sensitivity of the "high threshold", 2nd approach, constant "low threshold"

Marginal technology	***Maximum logistics cost = 14***	***Maximum logistics cost = 16***	***Maximum logistics cost = 18***	***Maximum logistics cost = 20***	***Maximum logistics cost = 22***
CCGT	6034 (68.9%)	5801 (66.2%)	**5633 (64.3%)**	5426 (61.9%)	5214 (59.5%)
Coal	2257 (25.8%)	2490 (28.4%)	**2658 (30.3%)**	2865 (32.7%)	3077 (35.1)

±2 change on the maximum logistics cost of coal power plants corresponds to approximately 1.5% change on the level of threshold at most. The shift affects the results by a change of approximately 200 hours of the year which is also 2% change on the number of hours. (TABLE 6.13).

TABLE 6.14: Change in costs and benefits in 2015 by "high threshold" shift. 2nd approach, wind

Costs and Benefits			***Maximum logistics cost = 14***	***Maximum logistics cost = 16***	***Maximum logistics cost = 18***	***Maximum logistics cost = 20***	***Maximum logistics cost = 22***
Benefits	**Avoided Emissions**	***CO_2 (tons)***	1,151	1,188	1,212	1,245	1,277
		SO2 (tons)	1.59	1.72	1.81	1.92	2.03
		NOX (tons)	1.79	1.91	1.98	2.08	2.18
		$PM_{2.5}$ *(tons)*	0.07	0.08	0.08	0.09	0.09
	Avoided Emission Cost (€)		90,352	95,197	98,433	102,615	106,810
	Avoided Operating Cost (€)		92,385	92,385	92,385	92,385	92,385
Total Benefits (€)			**182,737**	**187,582**	**190,818**	**194,999**	**199,195**
Total Costs (€)			**112,712**	**112,712**	**112,712**	**112,712**	**112,712**
Total Net Costs (€)			**-70,025**	**-74,870**	**-78,106**	**-82,287**	**-86,483**

Change in CO_2 emissions is around 2.5%; however, this is higher for the rest of the pollutants (around 6%). Change in avoided emissions cost is changes in between 3 to 5%, and total benefits are effected less than that: 2-3%. Moreover, although threshold change causes higher variety in net cost for incremental capacity increase of wind, the change is lower than the first threshold (4-6%) (TABLE 6.14).

Low threshold

TABLE 6.15: Sensitivity of the "low threshold", 2nd approach with maximum constant logistics cost of $18 per ton

Marginal technology	***y= 50%***	***y= 60%***	***y = 70%***	***y= 80%***	***y = 90%***
Coal	2953 (33.7%)	2890 (33.0%)	**2658 (30.3%)**	2383 (27.2%)	2052 (23.4%)
Others	174 (2.0%)	237 (2.7%)	**469 (5.4%)**	744 (8.5%)	1075 (12.3%)

At the first up and down 10% change on the level of threshold results in 3% change on the number of hours but this effect gets bigger when the level increases and get smaller to less than 1% on the lower levels (TABLE 6.15).

TABLE 6.16: Change in costs and benefits in 2015 by “low threshold” shift. 2nd approach, wind

Costs and Benefits			***y= 50%***	***y= 60%***	***y = 70%***	***y= 80%***	***y = 90%***
Benefits	**Avoided Emissions**	***CO_2 (tons)***	1,335	1,307	1,213	1,112	993
		SO2 (tons)	2.08	2.02	1.81	1.58	1.32
		NOX (tons)	2.25	2.19	1.98	1.76	1.51
		$PM_{2.5}$ ***(tons)***	0.10	0.09	0.08	0.07	0.06
	Avoided Emission Cost (€)		110,609	107,879	98,433	88,426	76,677
	Avoided Operating Cost (€)		95,508	94,902	92,385	89,369	85,346
Total Benefits (€)			**206,117**	**202,781**	**190,818**	**177,795**	**162,023**
Total Costs (€)			**112,712**	**112,712**	**112,712**	**112,712**	**112,712**
Total Net Costs (€)			**-93,405**	**-90,069**	**-78,106**	**-65,083**	**-49,311**

Total benefits change approximately 6% in the first up and down level shift and 5% at the second level of change. However, total net cost is not stable on the threshold level changes. By the level increase of threshold, not only avoided emissions cost but also avoided operating costs decrease. Level increase results in 15% reduction on the net cost for the year 2015.

Overall, between the two “high” thresholds, 2nd approach provides more robust results on marginal unit identification, total benefits and total net costs by change of 10%. “Low threshold" is more sensitive to the changes but still the impact stays lower than change applied to the threshold level for the results of total benefits. However, total net costs are significantly affected by the change in “low threshold” level increase. So, the threshold changes do not affect the results of emission costs significantly while total net costs are sensitive to the changes in “low threshold” and stay considerably stable to the changes in “high threshold”.

7. Conclusion

Greenhouse and, more generally, emission control of pollutants as well as security of supply concerns (including, but not only, fuel procurement security) are reasons that support RES technologies deployment, in particular for electricity generation. In addition, there are possibly other economic benefits linked to job creation and technological innovation. Under the current electricity market mechanisms, neither external benefits of RES nor the costs of fossil fuel-fired power plants are fully internalized in operating costs. Countries try to solve this issue by support mechanisms to promote RES investment and increase the share of RES demand coverage. Still, CO_2 prices are far too low to make an impact and RES have not reached to the desired levels.

In this study, beneficial marginal impacts of RES on emissions, operating cost reduction and adequacy gain are examined by developing a transparent and simplified methodology. Firstly, a detailed literature review covering different methodologies which include externalities of RES and their quantification was carried out. Secondly, based on the approach of Callaway, Fowlie and McCormick (2015), a methodology is developed for competitive markets. Emission, operating and adequacy cost savings steaming from thermal electricity substitution by RES technologies are computed. In particular, a new approach to estimate adequacy savings is proposed. Thirdly, the developed methodology is implemented for Iberian electricity system, and the robustness of the results assessed.

The study shows the importance of external impacts of RES to the system and their high share on the real cost formation. It also provides the breakdown of emission and operating cost, that is, savings by avoided CO_2, SO_2, NO_X and $PM_{2.5}$ emissions and savings by avoided fuel cost, carbon price, O&M costs and taxes separately. It is important to remark that these estimated benefits and net costs might be relevant to the justification of policy interventions and future policy design.

This methodology might be also applied to other European systems. It would be interesting to test to performance of the methodology in other regions as well as to compare the results among separate power systems. However, not all possible benefits of RES deployment are accounted for. So, examining macroeconomic issues such as economic growth, job creation, enhancement of innovation related to RES investments are interesting research lines to follow. Also, the studied benefits can be extended on the environmental effects by following life-cycle analysis for conventional and RES technologies. By doing so, impact of RES investments to the system can be evaluated in depth.

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Appendix A

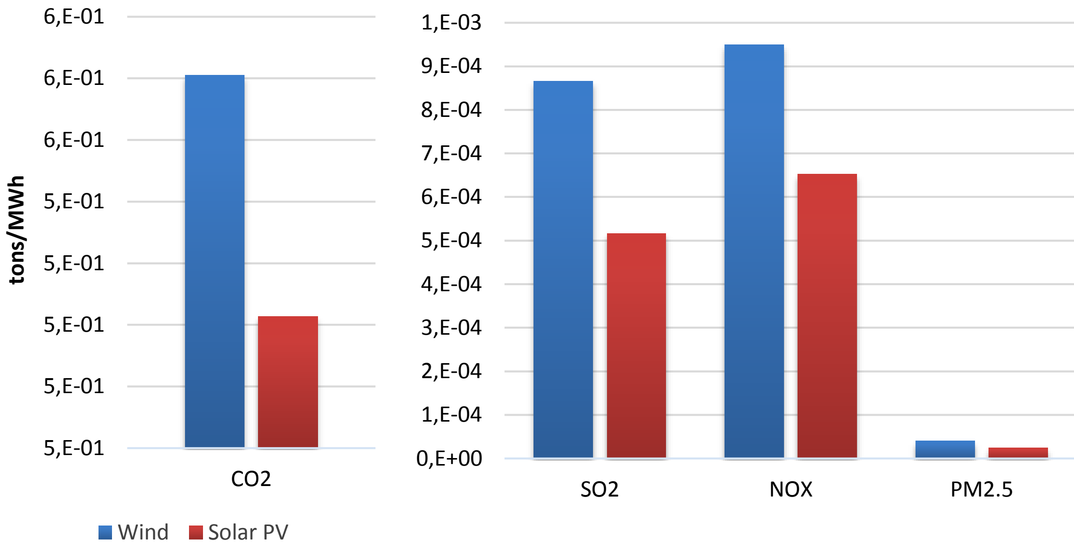

FIGURE A: Avoided emissions displacement rate (tons/MWh of RES energy generation) in 2015

In order to compare the RES technologies in terms of their emission displacement performance, avoided emissions displacement rate ($AEDR$) is calculated by the following formula and the results are shown in FIGURE A.

$$AEDR_{r,p}\left[\frac{t}{MWh}\right] = \frac{AE_p[t]}{\sum_{h=1}^{H} q_{r,h}[MW]} \qquad for\ each\ pollutant\ p\ and\ RES\ r$$