Retrospective and prospective analysis of policy incentives for wind power in Portugal.

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Retrospective and Prospective Analysis of Incentives for Wind Power in Portugal

Ivonne Peña

Abstract

Concerns over climate change impacts, goals to increase environmental sustainability, and questions about the reliability of fuel supply have led several countries to pursue the goal of increasing the share of renewable energy sources in their electricity grid.

Portugal is one of the leading countries for wind electricity generation. Wind diffusion in Portugal started in the early 2000's and in 2013 wind electricity generation accounted for more than 24% (REN 2013b). The large share of wind in Portuguese electricity production is a consequence of European Union (E.U.) mandates and national policies, mainly feed-in tariffs.

Discussions on the appropriate policy design and level of incentive to promote renewable energy adoption and meet further renewable capacity goals are ongoing in Portugal, namely in what concerns the level and duration of feed-in tariffs that should be provided to independent power producers. This, in turn, raises the question of whether the past feed-in tariff levels were well designed to achieve the goals of a larger penetration of renewables in the Portuguese grid. The policies to induce wind adoption have led to a growth in wind installed capacity and share of electricity generated by wind in Portugal from less than 1% in 2000 to approximately 24% in 2013, but questions arise on their cost-effectiveness and whether alternative policy designs would have led to the same goal.

The Portuguese wind feed-in tariffs are a guaranteed incentive which has varied between $85-$180/MWh over the last 20 years (ERSE 2011), and remained approximately constant since 2001 at $101/MWh. They are currently guaranteed for 20 years of production or 44GWh of electricity generation per MW installed (Diário da República 2013) - the longest period among countries with high wind electricity share. They do not incorporate any digression rate besides inflation, and are guaranteed for every unit of electricity fed to the grid. There are no power plants that have already been decommissioned despite being in operation for more than 20 years, favoring from new, detailed and hard-to-follow agreements in the legislation. All wind parks that are currently in operation have received feed-in tariffs since they connected to the grid, and are expected to keep receiving them at least until December 2019, and up to December 2036 - depending on year of connection and agreement under the most recent legislation (Diário da República 2013).

The 2020 renewable energy goals in Portugal include having 6.8 GW of installed wind capacity, which implies the connection of 2 GW in the next years. If no further grid investments are made and wind capacity increases up to 100 MW to the connection point that we analyze, total annual electricity spill is likely to range the 20% to 40%. If the connection grid policy is designed to allow for wind spill, already 'occupied' connection points will be available to new entrants, lowering the total investment costs for new wind parks and increasing their profitability.

This thesis is divided in three main parts: a first introductory section, a retrospective study of wind power in Portugal and a prospective analysis of the Portuguese wind power sector. The introductory section is a brief overview of the global renewable status, described in Chapter 1. Chapter 2 and Chapter 3 compile a retrospective study of wind power and the policies that have incentivized wind diffusion. We include in the discussion some references to the future wind power goals, but the results and policy recommendations are directed towards the existing connected wind power capacity.

Chapter 2 is a qualitative piece that describes in detail the motivation behind the Portuguese wind power diffusion, the policy changes over the last 20 years and the mechanics of the remuneration mechanism, i.e. the feed-in tariff formula variables and the actors of the wind power sector. We compare the Portuguese feed-in tariff with other European feed-in tariff designs and conclude that the incentive is one of the highest in Europe, contributing to the current Portuguese electricity system deficit of about $2 billion. If feed-in tariffs keep being fixed and do not incorporate any market variation, and renewables are prioritized to meet electricity demand, feed-in tariff net support per unit of electricity might be higher when the wind blows the most because moments with high penetration of renewable power might be correlated with low market prices. We find that wind power penetration is correlated with net exports to Spain. This might result in a net cost to Portugal and a subsidy to Spanish electricity consumers per unit of electricity traded. In total terms, the resulting subsidy is higher when the wind resource is larger as well, as the total amount of electricity that is exported increases.

In Chapter 3 we estimate the profits of wind power producers connected in Portugal between 1992 and 2010, and we recommend specific policy reforms that would lower spending in the form of wind feed-in tariffs. In particular, we assess four scenarios to decrease the level and/or period of the tariffs. We find that under the 2005 legislation - in which feed-in tariffs are granted for 15 years, all existing wind parks have positive NPVs varying between $0 and $12/MWh, when considering a 20-year lifetime. In fact, most of existing wind parks can stop receiving the feed-in tariff now (July 2014), and instead participate directly in the Iberian electricity market and still be profitable. Moreover, under the 2013 feed-in tariff reform that aims at decreasing the electricity system deficit, total spending will increase and wind parks will have larger profits than under the 2005 legislation. The motivation of keeping a high feed-in tariff comes from the need of liquidity that wind producers can provide immediately to the electricity system, which is required at this moment to comply with the E.U. economic agreements signed during the recession. Nevertheless, the environmental and energy dependency benefits of the Portuguese wind sector could have been achieved with as much as 25% less spending.

Later on, we move to analyze future wind power additions. Chapter 4 compiles a prospective analysis of the wind power sector in Portugal. We focus on new wind parks that will connect to critical lines of the distribution grid in two regions of the country, as part of the national 2030 wind power goals. In particular, we assess the implications of a 100% guaranteed availability of grid power capacity. We find that from the investor perspective, it is more profitable to bear some risk of wind power curtailment, because of the avoided costs that would otherwise be incurred to upgrade the grid. We also find that since there is ample room in the distribution lines to connect more wind parks, very few grid upgrades can allow to highly increase the distributed wind capacity with a low risk of wind curtailment. Moreover, even in scenarios with 'high curtailment' of 5% to 20%, projects are profitable. Thus, the Portuguese government should consider a policy where the guaranteed feed-in would be removed, and further assess the possibility of limiting profitability of the existing and new wind projects by introducing curtailment.

This work compiles two perspectives: first, a temporal perspective, in which past and future assessments of wind power diffusion are described. Second, a perspective on policy characterization, in which we present an assessment of two characteristics in the feed-in tariff design: the level/period of the tariff and the conditionality of prioritizing wind power over fossil-fuel resources with absence of risk of wind power curtailment. The level and period-related policy recommendations are considered for the existing wind parks, and are addressed mainly in Chapter 3. Considerations about grid capacity and introducing a risk of wind power curtailment are considered for subsequent wind power capacity additions, and are mainly considered in Chapter 4. In addition, notice that Chapter 3 focuses on avoiding excessive profitability of wind power parks while in Chapter 4 we analyze wind and grid capacity additions under the perspective of wind investors. Nevertheless, as we also find in Chapter 4 that profits are excessive, we do make recommendations that limit wind investor's revenue.

Portuguese decision maker should give serious consideration to revisions to the Portuguese feed-in tariff policy design. Most of the existing Portuguese wind parks to not need a feed-in tariff to be profitable. A value associated with the risk of wind power curtailment for subsequent additions should be incorporated in future policy design. We expect that this work will contribute to the Portuguese renewable policy in particular in light of Portugal's 2020 and 2030 wind power goals.

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1 Chapter 1: Global Overview of Renewable Power

Concerns over climate change impacts, goals to increase environmental sustainability, and questions about the reliability of fuel supply have led several countries to pursue the goal of increasing the share of renewable energy sources in their electricity grid.

At global level, electricity demand is increasing. Figure 1 shows that since 1980, global annual electricity consumption has three-fold (WB 2014), and continues increasing (see right axis). Even though this trend means that each year fossil fuel and renewable power technologies are being installed, it is evident that renewable power is leading the trend: annual generation presented a 32-fold increase between 1980-2011 (WB 2014). As Figure 1 shows, within renewables, both hydro and non-hydro[1] power capacity keep increasing. Together, they represent a quarter of total global power capacity installed (EIA 2014), but non-hydro renewable addition are being added faster than hydro capacity in the last decade – and 60% of non-hydro renewables' power capacity are wind parks.

In terms of electricity generation, global non-hydro renewable electricity generation represented more than 20% of renewable electricity production in 2011(WB 2014). As a share of total global annual power produced, non-hydro share had a modest increase during the 90's - from 1% in 1991 to 1.5% in 2001. It presented a major increase afterwards, and currently[2] it accounts for more than 4% of total global generation, displacing oil, nuclear and coal electricity generation share.

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[1] Non-hydro renewable electricity production includes all electricity coming from wind, solar, wave, geothermal,
[2] By 2011, most recent year for which data is available (WB, 2014).

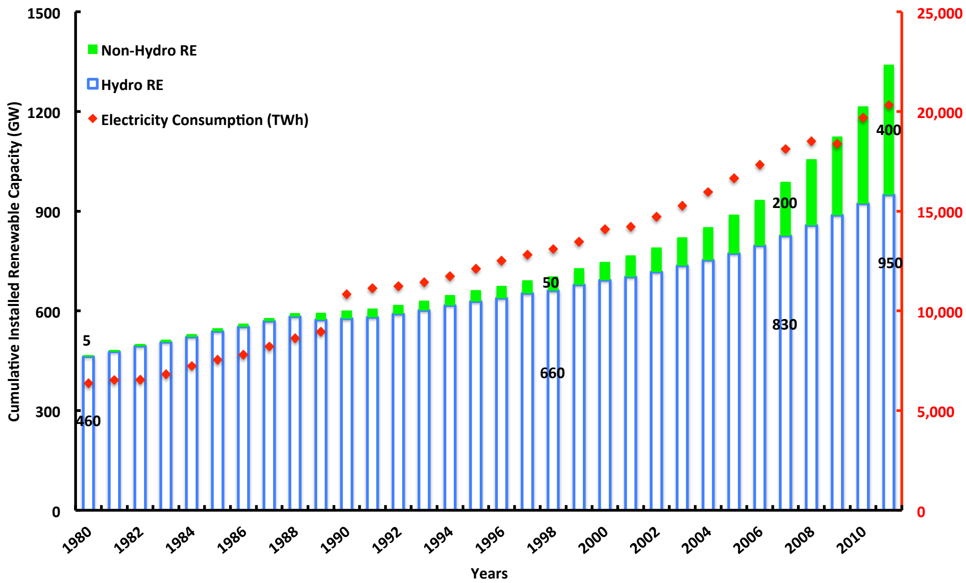


Figure 1 Global cumulative installed capacity of renewable power, including hydro, wind, solar, geothermal, wave and biomass technologies.

Approximate values for cumulative capacity of hydro and non hydro power technologies are shown for years 1980, 1998, 2007 and 2011. From the almost 400 GW installed of non-hydro renewable power technologies, more than 60% correspond to wind power installations in 2008-2011. (EIA 2014).

1.1 Leading countries in renewables and wind power

These increasing trends in renewable power are taking place in many countries around the world. In 2012, the U.S. installed more wind power capacity than capacity from any other technology, and renewable power added that year was half of total power additions. In the E.U, renewables accounted for 70% of power additions – the majority of which corresponded to wind and solar. In 2011, almost 21% of total electricity consumption in the E.U. came from renewable sources (REN21 2013)

Table 1 shows wind power installed at global level between 2005 and 2011. Between 2000 and 2011, global wind electricity share in non-hydro renewable power increased from 12% to almost 50%. The leading countries in wind power (in 2011, most recent year for which data is available for all countries) as share of total electricity generation are Denmark (29%), Portugal (18%), Ireland (17%), Falcon Islands (17%), Spain (15%), Aruba (9%), Lithuania (9%), Germany (8%), Greece (6%) and Nicaragua (5%) (EIA 2014).

Table 1 Global cumulative wind power capacity and total global electricity generation in 2005-2011.

Year	Global cumulative wind power installed (GW)	Share of wind power in cumulative non-hydro renewable power capacity	Total wind electricity generation (TWh)	Share of wind electricity generation in non-hydro renewable electricity generation
2005	60	51 %	104	26 %
2006	75	54 %	132	30 %
2007	94	58 %	171	34 %
2008	121	61 %	221	39 %
2009	148	62 %	276	43 %
2010	183	62 %	342	45 %
2011	237	60 %	446	48 %

Portugal is one of the leading countries for wind electricity generation. Today Portugal's cumulative wind power capacity is approximately 4,470 MW (REN 2013b), accounting for approximately 1.4% of total global cumulative wind power capacity (GWEC 2014).

Wind diffusion in Portugal started in the early 2000's – consistent with the global trend. In Portugal, in 2000, less than 1% of Portugal electricity production came from wind sources. By 2012 wind accounted for 20% (REN 2013b) of electricity production. The large share of wind in Portuguese electricity production did not happen overnight, and is a consequence of European Union (EU) mandates and national policies.

2 Chapter 2: Was It Worth It? A Review of Portuguese Wind Policies and Technology Diffusion

Paper to be submitted as an Invited Review (Invitation accepted in June 2014) in Energy Policy, with the submission planned for August 2014.

2.1 Abstract

This chapter describes the drivers behind the Portuguese wind power diffusion process, the policy mechanisms established, the actors involved in the sector and the main consequences of the large wind power share. The wind power diffusion process started in Portugal in the early 2000's, incentivized by a feed-in tariff (FIT) policy mechanism that called the attention of a variety of potential wind power investors. Connection licenses were granted across the country through public tenders in 2001, 2002 and 2005. Today, Portugal meets 24% of its electricity demand through wind power. We present an overview of the reasons why Portugal chose wind power to comply with the European Commission climate change and energy goals. We provide a detailed review of the wind FIT policy and a description of actors involved in wind power production growth. We estimate the environmental and energy dependency gains achieved through wind power generation, and we highlight the correlation between wind electricity generation and electricity exports. We compare the Portuguese FIT with other European FIT designs and discuss the relevance of a FIT reform for subsequent wind power additions.

2.2 Introduction

Concerns over climate change impacts, goals to increase environmental sustainability, and questions about security of fuel supply have led several countries to pursue the goal of increasing the share of endogenous renewable energy sources in their electricity grid.

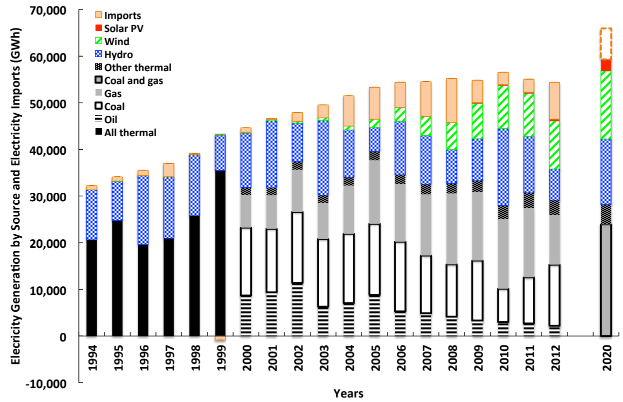
Portugal is one of the leading countries for wind electricity generation. Wind diffusion in Portugal started in the early 2000's. In 2000, less than 1% of Portugal electricity production came from wind sources – by 2013 it accounted for more than 24% (REN 2013b) (see Figure 1a and 1b). Currently, wind electricity generation is the second largest contributor in renewable electricity production in the country, after hydropower. By April 2013, wind power installed was 4,464 MW, from which 4,239 MW are now connected to the grid. The national goal to meet renewable targets set by the European Union is to attain 6,800 MW of cumulative wind power capacity by 2020 (Portugal 2010).

The large share of wind in Portuguese electricity production did not happen overnight, and is a consequence of both European Union (E.U.) mandates and national policies. This paper reviews the motivation behind the deployment of wind power in Portugal, the policies that have incentivized wind power investments, and some of the consequences of the high wind power penetration in the electricity sector.

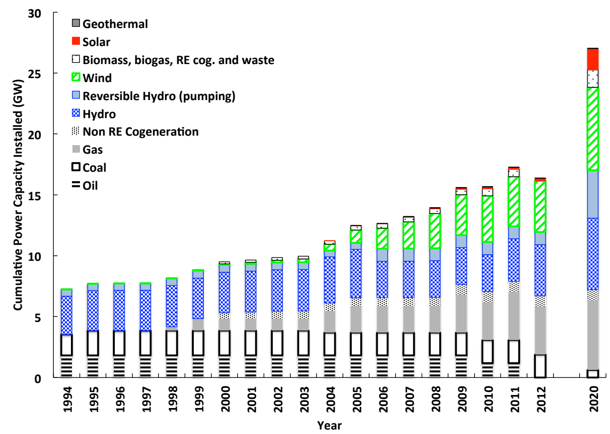
Portugal has a large dependence on energy imports in its primary energy consumption. For the past 20 years, imports constituted always more than 80% of total primary energy consumption (DGEG 2014). Endogenous resources are scarce, and predominantly renewable. Currently, electricity consumption represents 38% of total primary consumption, and has increased remarkably in the last 15 years (DGEG 2014), with the exception of the last couple of years, where the economic downturn has resulted in a reduction of electricity demand. Figure 2 shows, in panel A, the net imports and electricity production by source; in panel B the total electricity generating capacity installed by sources, and in panel C the prices and tariffs for electricity in Portugal for different sectors. All the plots in Figure 2 are from 1994 to 2012, and show the 2020 goals where those are available.

Figure 2 shows that electricity imports from Spain have been slowly increasing, but constitute less than 10% of total electricity consumption. Fossil fuel power capacity is expected to decrease due to the phase out of coal power by 2017. The main expected additions correspond to natural gas power plants, pumped-hydro capacity and wind power. Spot market prices are about half the FIT paid, which is comparable to residential electricity prices (excluding taxes and levies). When taking into account taxes, residential electricity prices increase at least by 60%, and can even threefold. Such taxes and levies include a portion that covers the spending in the form of renewable energy FITs.

A



B



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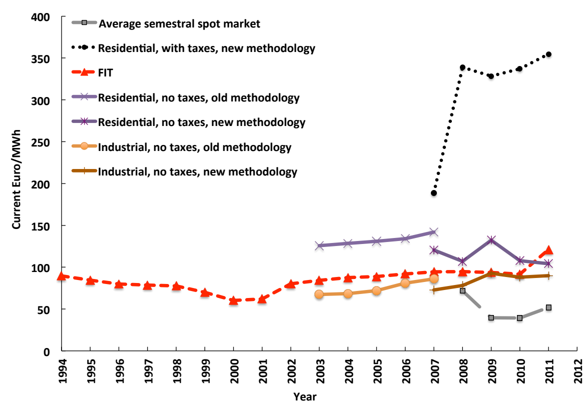

Figure 2. A. Net imports and electricity production by source; B. Total existing electricity generating capacity installed by source; C. Prices and tariffs for electricity in Portugal for different sectors. All figures from 1994 to 2012, and showing 2020 goals where those are available.

Sources: A: plot from authors using data from DGEG. 2020 goals based on electricity consumption forecast from (REN 2011b), RE-E goal of 60% and RE targets from (ECN & EEA 2011); B: (GEO 2014; EIA 2014) and 2020 goal from (REN 2013; Ministério da economia e do emprego et al. 2013); C:(ERSE 2012a; EC 2014a; OMIP 2012)

2.3 Policy drivers for wind diffusion

In 1998, the EU signed the Kyoto Protocol and committed to an overall goal of 92% limitation in greenhouse gases between 2008 and 2012 compared to 1990 levels. The European Council approved the Protocol in 2001. Each member state ratified their mechanisms of action by June 2002 (E.U. Council 2002). While there were several communications in the then European Economic Commission as early as 1986 on the importance of renewables and overall climate change goals for the EU[3], it was only by 2001 that the European Commission issued Directive 2001/77/EC which included specific goals to be met by renewable energy sources for each member country. This directive established a EU goal of achieving 12% of gross domestic energy consumption coming from renewable energy sources (hereafter denoted by RES), and 22.1% of gross electricity consumption from RES by 2010 (EC 2001).

Under Directive 2001/77/EC, Portugal committed to achieve a large share of electricity (39%) generated from RES by 2010, though Portugal has already a very large renewable base to begin with. The national roadmap to achieve the 2010 goal was established in 2001 in the Energy Efficiency and Endogenous Energy Program (E4 Program), which included increasing the total electricity generating capacity of renewables from 4,600 MW in 2001 to 8,800 MW in 2010 (Ministério da Economia, 2001). Since most of the renewable capacity at the time was relying on hydro power, and the expected hydro capacity additions were not enough to comply with the renewable goals, Portugal determined that wind power was the most suitable technology to develop (EUROPA 2003). Wind power was appealing as a mature technology in a country with reasonable unexploited wind resources (see Figure 3). Wind power was therefore established as

[3] There Green and White Papers in 1997 (EC 1997), which are document with non-binding goals that generally preceed EU directives.

the main technology and energy source to attain the renewable energy goals, and a goal was set to increase wind capacity from 80 MW in 2001 to 3,300 MW in 2010 (Ministério da Economia 2001).

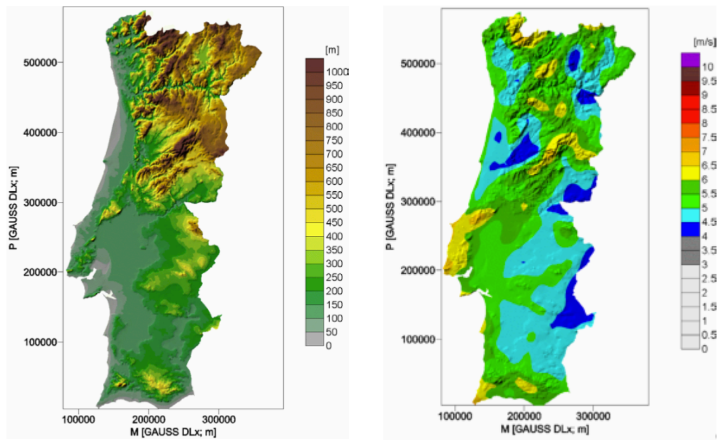

Figure 3. Portugal elevation map (left) and average wind speed at 60 m height estimated by Teresa Simões (Simões 2004).

In 1997, the then EC signed the Kyoto protocol, which required that the EU, as a whole, had to meet a target of 8% greenhouse gas reductions during from 2008 to 2012 when compared to 1990 emissions levels. This overall EU goal was then translated to specific goals for each EU member state. By 2002, the EU approved the Protocol on behalf of the Community under Decision 2002/358/EC, which established the specific values for the goals that had to be met by each member country.

Portugal was entitled to an emissions increase of 27% (387 MMtonCO2e) between 2008 and 2012, when compared to 1990 (Ministério do Ambiente 2006), on the grounds that it's economy had to increase to get closer to the EU. Targets were set and ratified in the late 90's at E.U. level and in the early 2000's in the member states.

Over the course of the early 2000s, Portugal published it's national energy plan under the E4 Program, issuing a "National Programme for Climate Change" between 2004 and 2006. It had a special emphasis on renewable energy, efficiency and transport measures in the energy sector, which accounted for more than 70% of total CO_2 emissions by 2004 (Ministério do Ambiente 2006). The goal for renewable energy sources under the climate change program was set in alignment with the already existing E4 Program.

By 2007, as a result of ongoing EU discussions and EU's Climate and Energy Package, renewable energy goals were set a higher goal: 45% of electricity consumed should come from renewable energy sources by 2010 (Diário da República 2008). The Climate and Energy Package resulted in a new EU Directive, 2009/28/EC, established what has become known as the 20-20-20 goals. This new Directive states binding national goals for 2020 to reach an overall 20% of E.U. final energy consumption coming from renewable sources, a 20% reduction in E.U. greenhouse gas emissions from 1990 levels and a 20% improvement in the EU's energy efficiency. By 2010, each member country had to present a national plan to achieve their respective target. The target for Portugal is to have 31% of the gross final energy consumption coming from renewable electricity by 2020 (EC 2009). To be clear, this is indeed a goal for all final energy consumption, not only for electricity generation. Portugal established a national renewable energy strategy (NREAP) to have 60% of its electricity produced from renewable energy sources in 2020, and 24% of electricity coming from wind and to have 6.8 GW of wind onshore capacity installed by 2020 (EU Commission 2010), along with 10% of the energy consumption in the transport sector derived from renewables.

A wind power plant requires a connection license or right to connect to the national grid and sell electricity to the utility. Between 1988 and 2001, there were very few wind parks, and the connection license process was quite unclear, deterring potential wind investors. By 2001, the connection procedure became more transparent, with detailed procedures established to allocate connection permits for power producers. Changes in 2001 legislation also established that the project developer should cover the extra financial costs that might arise due to grid extensions. The legislation states that the grid operator and the distribution company are responsible for planning the extension and/or update of the grid, and that all procedures to grant connection rights are public.

As of 2001, there are two procedures to get a connection right: a direct procedure in which parks individually ask for a connection license when the Portuguese Directorate of Energy (DGEG) establishes available connection points, and a public tender in which specific criteria apply to grant connection licenses. The majority of connection licenses in Portugal for wind power generation have been awarded in public tenders opened in three years: in 2001, 2002 and 2005, with 1GW, 2GW and 1.7 GW awarded, respectively. In particular, the last public tender opened in 2005 awarded between 2005-2008 to ENEOP (1 GW), Ventinvest (0.5 GW) and 12 different developers (0.2 GW). Wind projects corresponding to more than 10 GW requested a connection license before 2008. Only 4.7 GW received a connection right, and about 80 percent of these were already connected by December 2010. The 20 percent left were either under construction or waiting for an environmental license by December 2010 (ERSE 2011; ERSE 2012a; Sá da Costa 2012).

Even though the majority of the wind parks are connected in the windiest regions (Center and North), the allocation of wind parks may not have resulted in the construction of wind parks in the best sites. The reasons include:

i. *Information system:* At the time the first licensing requirements were published, there was very little information concerning wind speed distributions with high resolution. Only general charts were available and there was a total absence of local wind information.

ii. *Geographic system:* At the time the licensing requirements were published, there was little availability of land for wind developments, mainly because:

   a. Land owners were naturally skeptic with the introduction of a new technology.

   b. The process of negotiating land is very complex, as there are many owners for a given parcel of land and grid connection might need to pass across several parcels.

   c. There were not electrical network connections to the best places, as the network was orientated away from mountains and closer to load centers. Even in cases where network lines existed, connection capacity restricted the available sites for wind.

   d. There are environmental restricted areas. The average percentage of protected areas in NUTS III regions is 8.5%, ranging between 0 to 53.5% (see Supplemental Information for details).

iii. *Economics:* At the time the licensing requirements were published, the projects were economically viable regardless the wind resource. Public tenders dictated that projects had to be submitted in a short time span. There was no time and/or information to assess the tradeoff between increasing electricity production in windier regions and investing in longer and more expensive grid extensions (Hoppock & Patiño-Echeverri 2010). Thus, it became more important to have a land license in a region close to an existing connection point rather than to look up for a place with the best wind conditions. For example in 2002, there were 7 GW of projects that were presented and only 2 GW were granted, which shows that all these projects were economically attractive due to the high FIT subsidy, no matter the location. In fact, in previous work we show that most of existing wind parks in Portugal have been oversubsidized (Peña et al. 2014).

Even though for the 2005 tender there was more solid wind distribution data, the main selection criteria was the development of a wind industrial cluster. Thus, it did not guarantee that the sites selected by the wind developers were optimal, but that the chosen developers had the economic capability of creating a large industrial investment.

Portugal also aimed to reduce energy dependence from 87% to around 74% in 2020 (EU Commission 2010), representing €2 billion in savings. Lastly, Portugal also aimed to consolidate an industrial cluster of wind power, creating 100,000 new jobs in addition to the existing 35,000 jobs associated with the production of electricity from renewable energy sources by 2020 (EU Directive 2009). This cluster was created, and it includes five companies and four specialized centers that in conjunction with other national and foreign companies can provide all services to the installation and maintenance of wind parks. A description of this cluster is provided in section *Additional details on wind policies in Portugal*, in the Supplemental Information of Chapter 3.

Energy planning reports of the Transmission Grid Operator (REN) and the Energy Direction (DGEG) consider lower wind targets in their roadmaps, such as 5.3 GW and 6.4 GW of wind cumulative capacity by 2020 and by 2030, respectively (Ministério da economia e do emprego et al. 2013). Because to the extent of our knowledge Portugal has not submitted a revised National Renewable Energy Plan to the European Commission, we consider that Portugal's goal is to achieve 6.8 GW by 2020.

2.4 Policy mechanisms established by Portuguese law

While the EU requires overall renewable goals for each individual member-state, it is up to each member to then select a mix of energy technologies and sources, and policy mechanisms and instruments that are needed to achieve these goals. Countries have pursued a variety of mechanisms, such as price or quantity-based policies (Van Dijk et al. 2003). Price-based policies include feed-in tariffs (FITs), and quantity-based mechanisms include renewable portfolio standards (RPS) and bidding systems. In Table 2 we provide a table with the different mechanisms currently being used by different countries.

Table 2. Table showing renewable energy support policies in some E.U. countries.
Based on REN21 2014 report (REN21 2014).

	Feed-in tariffs or premium payment	Electric Utility Quota obligation or Renewable Portfolio Standard	Net metering	Tradable Renewable Energy Certificates	Tendering
Austria		x		x	
Denmark	x		x	x	x
France	x			x	x
Germany	x				
Italy	x	x	x	x	x
Portugal	x	x			x
Spain			x	x	
Switzerland	x				

Portugal has relied on feed-in tariffs as the key mechanisms for wind diffusion. The electricity commercial agent Electricidade de Portugal Serviço Universal (EDP SU) is required to purchase power from wind IPPs at a rate estimated each month for each wind park. Even though Europe is known for the promotion of renewable power through feed-in tariffs, the design, period, and level of the feed-in tariffs differ greatly across countries. Figure 4 shows a timeline of the feed-in tariff adoption in Portugal and other countries, along with the major E.U. Directives that set the main framework for renewable energy incentives.

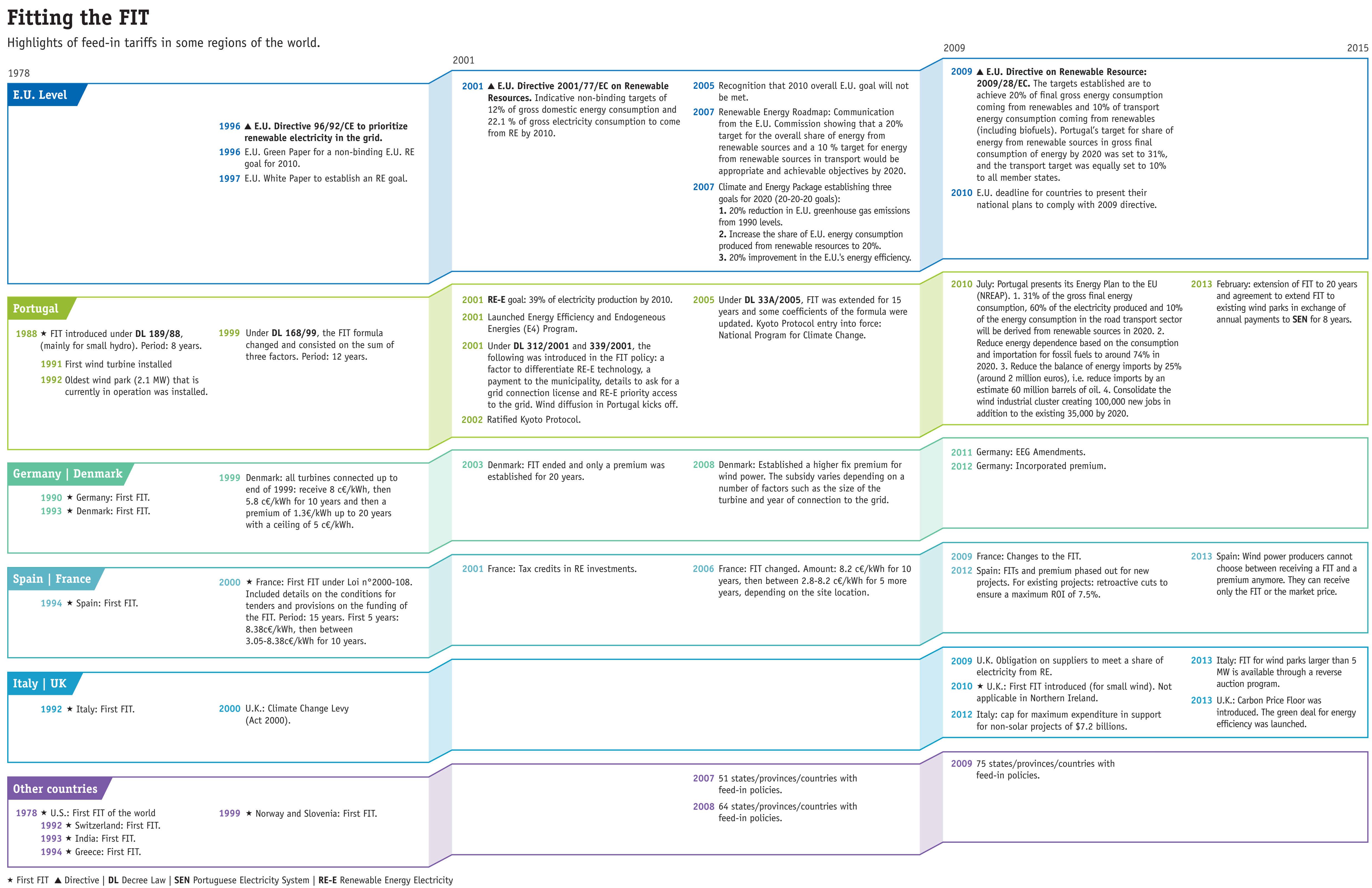

Figure 4. Timeline highlighting the adoption of feed-in tariffs in Portugal and other regions of the world.

Figure constructed by the author and based in multiple sources. (Mendonça 2007; Mendonça et al. 2009; Couture & Gagnon 2010; Deutsche Bank Research 2012; Lang & Mutschler 2012; EC 2013a; Diário da República 1988; Diário da República 2013; Diário da República 2001b; Diário da República 2005; Diário da República 1999)

When the period and conditions are compared across countries, the Portuguese feed-in tariffs for existing onshore wind parks is particularly generous. Other countries, such as Germany and Italy, are now transitioning from electricity production based incentives, to market integration incentives, such as flexible premiums and management bonus. These are incentives granted on the top of the market price, to grant financial certainty to the investor at the same time that renewables are directly incorporated in the electricity spot market. Instead, Portugal has continued to pursue a strategy that relies on feed-in tariffs. For example, as recently as in 2013, a new law ratifies the feed-in tariffs as the key policy instrument to incentivize wind power (Diário da República 2013).

The feed-in tariff scheme in Portugal has been designed from the beginning as to not incorporate any financial risk to the wind producer. The feed-in tariffs are paid on a MWh of electricity produced basis, and have ranged from $85 to $180/MWh ($2005) over the last 20 years (ERSE 2011). Since 2001, the average national feed-in tariff has been remaining relatively constant around $103/MWh. Currently, the tariff is guaranteed for 20 years of production or until the site reaches 44GWh of electricity generation per MW installed (Diário da República 2013).

FITs were first implemented in 1988. Between 1988 and 2001, the FIT value was technology and source neutral, i.e., all sources of electricity generation received the same FIT amount per MWh produced. Also, until 2001, there was no specific procedure for applying for connection licenses to the grid. Since its inception in 1988, FIT payments to power producers are defined in Portuguese law according to a formula that is computed for each power producers and for each month.

There have been changes to this formula and period of remuneration in 1999, 2001, 2005 and 2013. A key transition in 1999 was that the tariff paid to a wind producer was defined as the sum of three factors – called fixed (*PF*), variable (*PV*) and environmental factors (*PA*). In addition to those, in 2001, a factor for technology differentiation (*Z*) was introduced. The current tariff is computed as:

$$Payment_m = T \times [PF + PV + (PA \times Z)] \times inflation \ \times trans \qquad (1)$$

Where *payment* (in euros) is the payment to the power producer in month *m*; *PF* is a fixed value, independent of the electricity generated (in euros), *PV* is a variable portion of the payment, which is a function of how much power is generated by the wind park, and *PA* is a constant environmental factor (in euros) which accounts for the fact that renewables are contributions to a decrease in environmental and health damages associated with the use of fossil fuel generation. *Z* is a factor that takes different values for different renewable energy sources and technologies. *T* is a factor that accounts for the time of the day electricity is produced (non-dimensional), and *inflation* and *trans* correspond to inflation adjustment (non-dimensional) and avoided electricity transportation and distribution costs arising from the use of wind power at local level (non-dimensional). Table 5 in the Supplemental Information shows the values of each factor according to the main decree-laws in Portuguese legislation, and Table 3 below shows the current values used to remunerate wind power producers, in $2005 values. Figure 5 shows the nationally averaged tariff per MWh paid for each of the seven renewable energy technologies from 2000 to 2010.

Table 3. Illustrative values used in the most recent formula to compute the tariffs for wind in Portugal.

Factor	Units	Value
PF (Fixed factor)	$/kW	Between $3 and $7
PV (Variable factor)	¢/kWh	44
Z*PA (Environmental factor)	¢/kWh	43
T	Non dimensional	Between 0.625 and 1.25
Trans	Non dimensional	Between 1.015 and 1.036

All dollar values given as $2005 constant values.

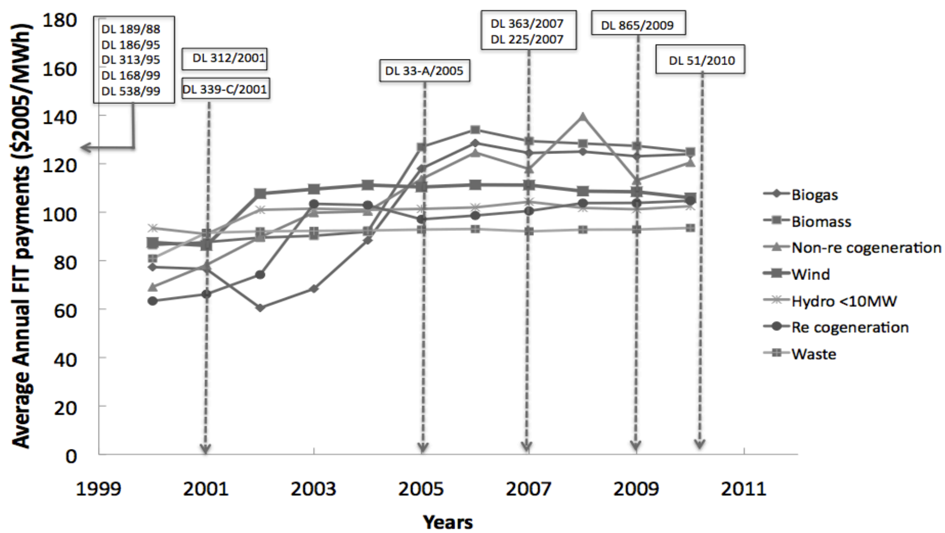

Figure 5. Average annual feed-in tariff payments in Portugal from 2000 to 2010 for several renewable energy technologies and sources.

Figure based on (Azevedo & Venâncio, working paper).

The text boxes labeled as D.L. stand for key changes in the renewable renumeration over time and are summarized in the Supplemental Information. Solar FIT is not shown due to its large difference compared with the rest of technologies: national average solar FIT was $710/MWh, $680/MWh and $380/MWh in 2003, 2005 and 2010 respectively (solar capacity installed appeared in 2003 in Portugal). Data from (ERSE 2012a). Conversion to dollar assumes $1.24 dollar/euro.

Using information from public data sources (ERSE 2012a; DGEG 2014), and applying the detailed formulas and factors included in each of the decree-laws issues by Portugal since 1988, we have computed the total annual spending in wind tariff payments from years 2000 to 2010 to identify the corresponding share by each factor of the formula. We compare such estimates with the actual reported payments as listed in (ERSE 2011). The annual payments grew over time, reaching an impressive more than $1 billion by 2010. As a comparative measure, total GDP in Portugal by 2010 was $234 billion.

The discrepancy between our estimated values and the actual payments is likely to be due to the *T* and *trans* factors – factors that correspond to the time of the day at which electricity was produced, and the avoided transmission costs, respectively. In our estimates, we used the average of the limits imposed in the legislation.

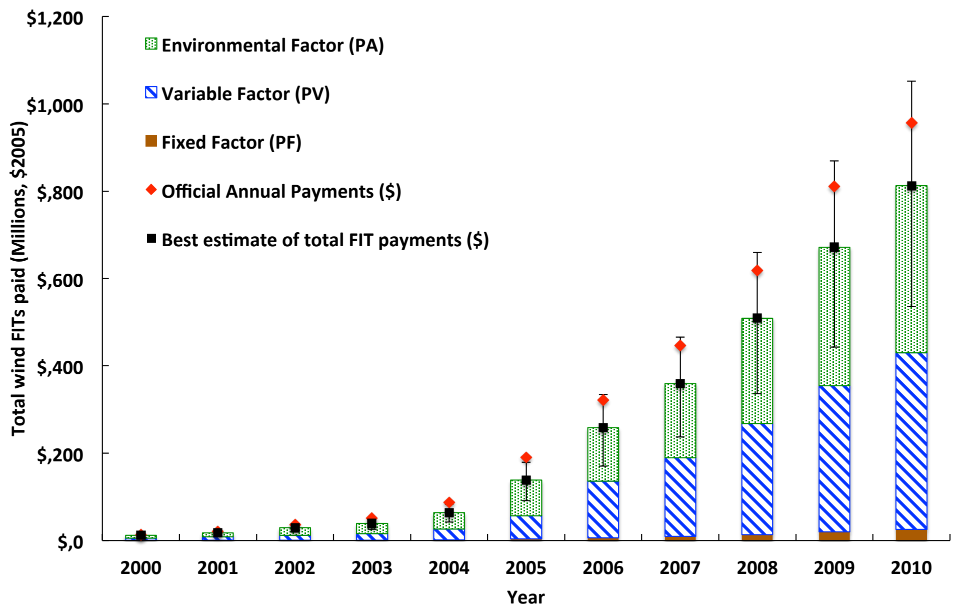

Figure 6 Author estimates of total wind tariff payments to wind power producers, and actual reported payments from 2000 to 2010.
Error bars correspond to high and low *T* and *trans* factors.

There are no wind sites that have already been decommissioned up to date, despite the fact that some of these wind parks have been in operation for more than 20 years. All wind parks that are currently in operation have received the tariffs since they first connected to the grid, and the older parks, which were connects in 1992 and 1993, are expected to keep receiving it at least until December 2019. The most recent wind parks will receive the tariff until December 2036 (Diário da República 2013). Discussions to alter the level of wind power remuneration downwards have not been successful: at the end of 2013 a proposal to include a production tax to renewable producers had severe objections due to the previous agreements with Chinese-EDP stakeholders (Dinheiro Vivo 2013).

To the extent of our knowledge, Portugal is the country with the longest FIT period established today in, and with no policy instruments that transfers any market risk to the developer. Moreover, it is the country with the longest FIT period that has already a mature wind power sector. In comparison with other leading countries the Portuguese wind support policy would need to be revised to follow the maturity of wind technology, as was done by many other EU countries.

2.5 Wind Power Diffusion in Portugal

The map in Figure 7 shows cumulative wind power capacity installed in the Portuguese regions (North, Center, Lisbon, Alentejo, and Algarve) as of 2010. As of December 2011, there were 211 parks. Cumulative capacity installed is very concentrated in the Center region. The municipality with the largest single capacity installed Pinhal Interior Norte, located in the Center region, with 563 MW installed by December 2010. This municipality alone constitutes 14% of the national cumulative wind capacity installed.

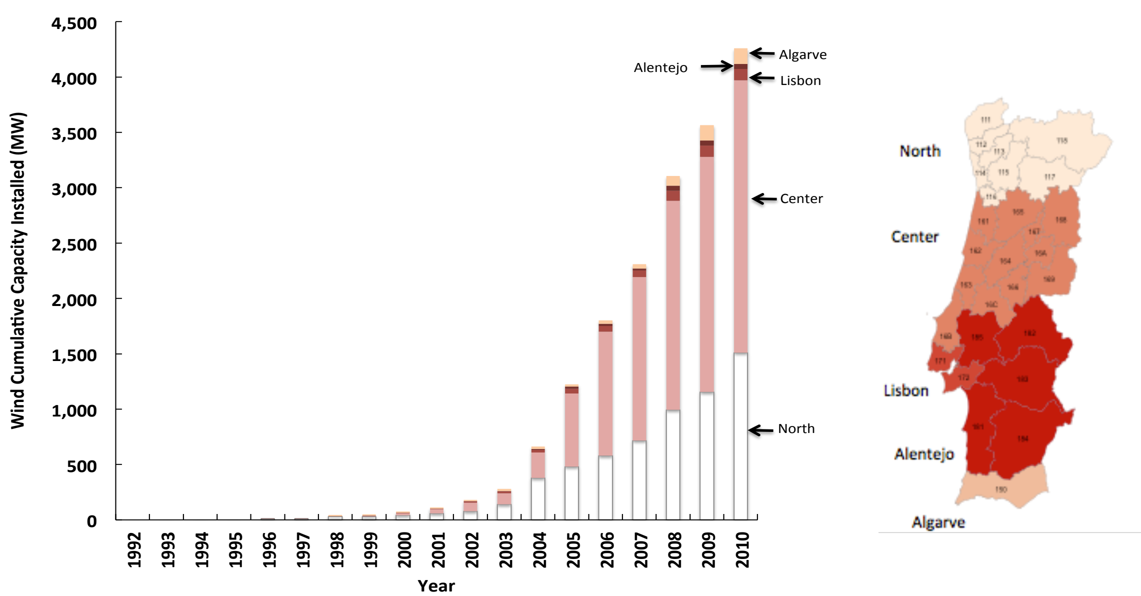

Figure 7. Wind Cumulative Capacity in the five main regions (NUTS II) of Continental Portugal between 1992-2010.
Current wind cumulative installed capacity (by December) 2010 is approximately 4200 MW. Alentejo: 50 MW, Lisboa: 100 MW, Algarve: 140 MW, Norte: 1500 MW, Centro: 2400 MW (INEGI 2010; INEGI 2011). The numbers in the regions correspond to the number.

Figure 8 illustrates the rapid growth in wind capacity for different municipalities by highlighting the cumulative capacity installed in each municipality in 2002 (left) and in 2010 (right).

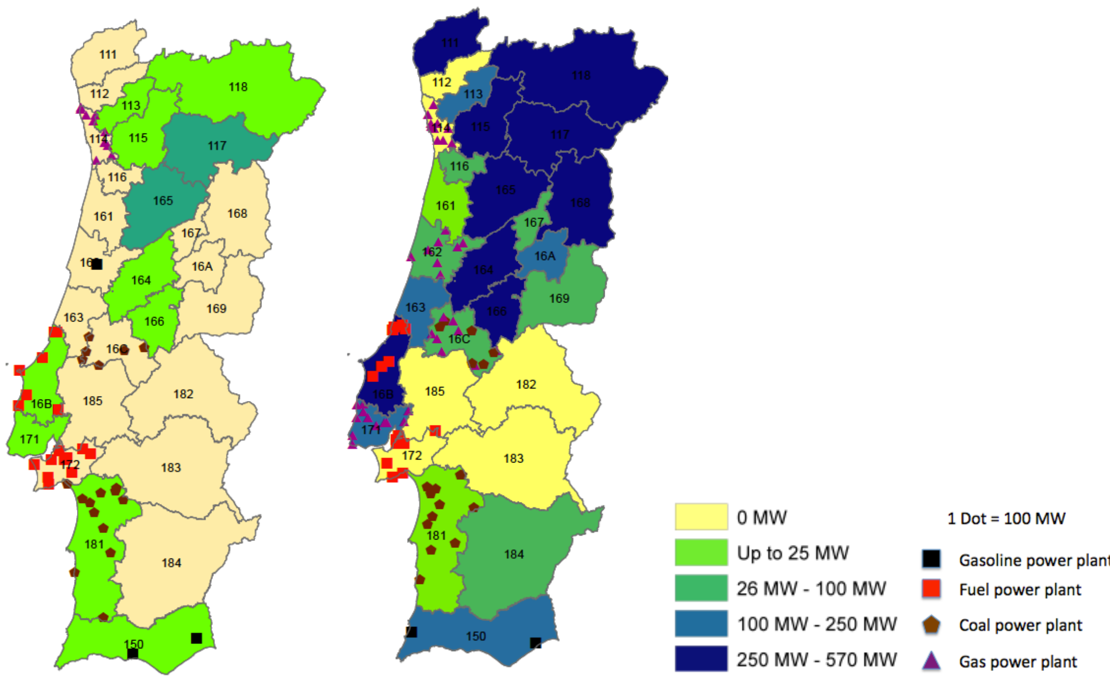

Figure 8 Wind and Fossil fuel-based Cumulative Capacity in the 28 NUTS III regions of Continental Portugal in 2002 (left) and 2010 (right).
Figure constructed using data from (REN 2011a; INEGI 2010; INEGI 2011; IGEO 2011) The color code corresponds to regional wind cumulative capacity and the dots correspond to fossil fuel power. The dots do not represent exact location. 'Fuel power plant' corresponds to 'fuelóleo' or 'fuel' in Portuguese, different from 'gasóleo' (translated as gasoline in the map), i.e. fuel and gasoline power plants shown are oil-based plants. Total fossil fuel capacity installed in 2002 is 4890 MW, from which gas accounts for 20% (990 MW)[4] Total fossil fuel capacity installed in 2010 is 7,400 MW, from which gas accounts for 52% (3,800 MW)[5].

2.6 Key players in the Portuguese Wind Development

In Portugal, the wind electricity is must-take. The main intermediary is *Electricidade de Portugal Serviço Universal*, or EDP SU, the trading agent that buys electricity from the wind power producers, and from other renewable electricity generators, and in return pays these

[4] If the gas and fuel power plant Carregado is included and assumed to run only gas, the total cumulative gas power capacity installed by 2002 is 1463 MW (30% of total cumulative power capacity).

[5] If all capacity of the fuel and gas plant Carregado of 710 MW is included, gas accounts for 61% of thermal electricity installed capacity.

renewable power producers the feed-in tariff value. Other commercial actors buy electricity from the traditional power generators through Power Purchase Agreements (PPAs or CAEs in Portuguese), Maintenance Equilibrium Contracts (MECs or CMECs in Portuguese) or directly in the market (Quejas Machado Gil 2010). All the electricity trade goes to the Spanish and Portuguese electricity market pool (MIBEL), including from renewable and non-renewable sources, and is traded across commercial actors, such as EDPSU, AUDAX, GNEL and UFCO.

The feed-in tariff is provided to all wind power producers. The tariff is funded, in part, through the redistribution of its costs across all electricity consumers.

In Figure 8, we show the ownership of wind capacity installed, as of 2010. Three key players, ENEOP2, EDP Renováveis, and Iberwind account for 45% of the total wind installed capacity.

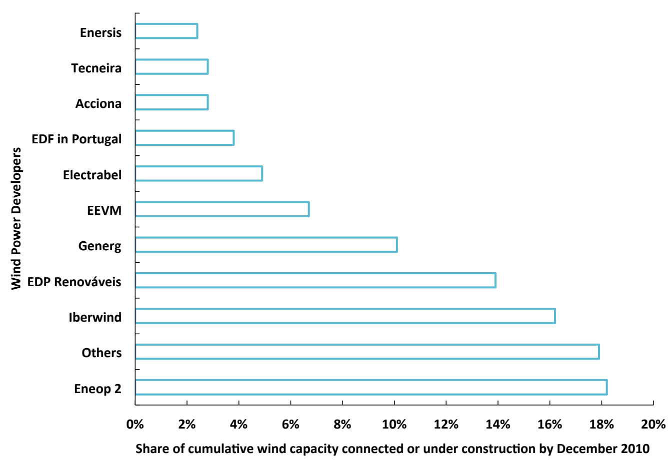

Figure 9 Owners of wind power capacity, by share of cumulative capacity installed, licensed or under construction by December 2010.
(EDP 2011; INEGI 2010)

The majority of developers are multinational companies and major Portuguese and foreign economic groups with activities in other environmental sectors. For instance, the largest energy operator in the country, Energy of Portugal (Energías de Portugal, EDP), has eight subsidiaries including electricity distribution, national gas electricity generation and renewable power companies, and directly owns 39 wind parks and another 21 parks through ENEOP2, accounting approximately for 600 MW (EDP renováveis 2012).

Figure 10 shows a scheme of the actors involved in the wind FIT mechanism in Portugal. EDP SU (EDP Universal Service) is the trader agent that is required to buy all electricity from wind producers (and all other renewable power producers) at the feed-in tariff rate (a). Later on, EDP SU trades it in the Iberian Electricity Market (b). The commercial agents that operate directly in the market (numerous) sell the electricity to other commercial agents or to final consumers at different rates under liberalized contracts that still include regulated tariffs (c). There are 11 last resource commercial agents (CUR in Portuguese), and EDP SU is the largest. Thus, EDP SU operates both as a buyer/seller of wind power, as well as a commercial agent under contracts with final consumers. The rate to consumers offered by the last resource commercial agents includes an energy tariff, a distribution and transmission tariff, a "global use of the system" tariff and a commercialization tariff (d) (ERSE 2012b). The payment to support renewables is included in the "global use of the system" portion of the tariff (e). The payment to support renewables is not equal to all consumers, and is differentiated according to the voltage level connection, and is lower to consumers in high voltage levels (i.e. industries and large consumption points as trains and other public services).

Over time, there was a financial deficit accumulated by the Portuguese government, in part due to a failure in the design of the feed-in tariff scheme (f). The energy trading agents (EDPSU) sells energy in the market below the feed-in tariff value. In general, all electricity coming from wind power represents a net economic cost to the Electricity System, because the spot electricity market price at which wind electricity is traded is lower than the feed-in tariff paid to wind power producers. In average, the net economic cost associated with this different is about $40 per MWh. Part of this difference is then compensated by the rate payers. However, the amount charged to the rate payers has generally been below the needed amount required to fully support the difference between the feed-in tariffs value and the market price, under the justification that it would otherwise lead to very high end-use electricity rates. This accrued deficit is contributed to what is called the general electricity system (SEN) deficit (other incentives and subsidies in other parts of the energy system also contribute to this deficit).

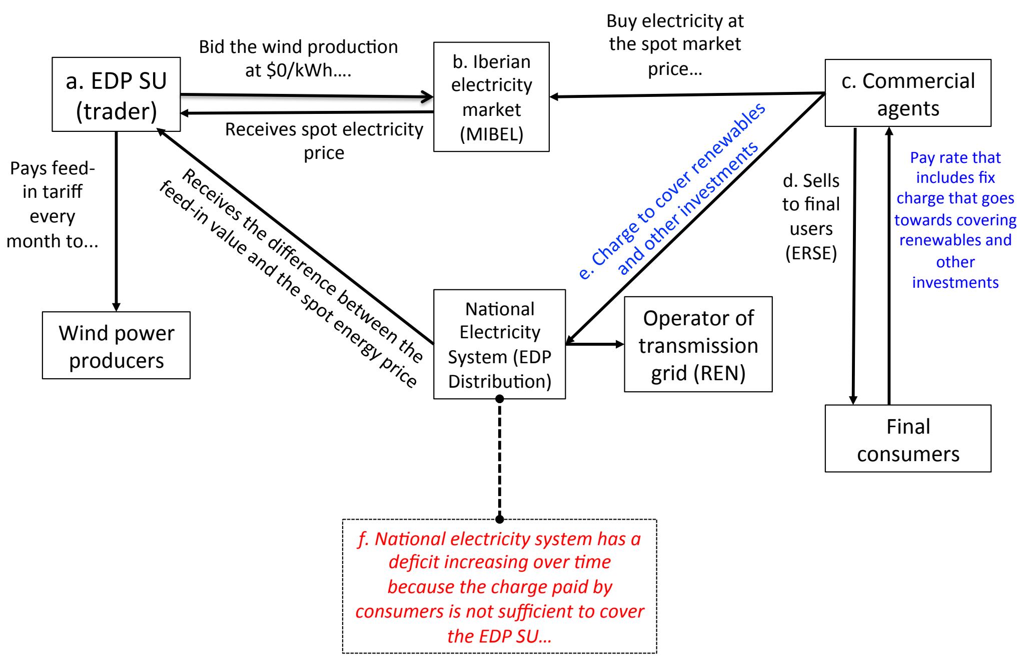

Figure 10 Actors in the wind FIT scheme in Portugal.

The total deficit of the electricity system – including the deficit attributable to renewable incentives, purchasing power agreements and other, is currently in the range of $2.5 billion[6] (Dinheiro Vivo 2012a; Ferreira 2012; Gomes 2012). There are now mechanisms in place since May 2011 to reduce the electricity system deficit that are followed up by the European

[6] Estimates the deficit range from 1,750 million to 1,800 million euros. Assumed exchange rate: 0.72 euros/dollar.

Commission, the European Central Bank and the IMF, and include restructuring the feed-in tariff scheme (EC 2014b). In the last assessment of the Portuguese Assistance Programme, the EU Commission lists as a key structural reform in the energy market "the reform packages aimed at reducing excessive rents and cutting the electricity tariff debt" (EU Commission 2014). In the eleventh review of the Portugal Program, a target of eliminating the tariff-debt by 2020 was considered, which assumes an increase in electricity prices of about 2% per year. In addition, other measures are expected to be produced by the Portuguese Authorities (EC 2014b).

As part of the tariff-debt reduction program, Portugal re-designed its feed-in tariff policy. In February 2013, it established that wind producers should pay to the electricity system approximately \$7,000/MW-installed per year, between 2013-2020 (Diário da República 2013), in exchange of a feed-in tariff period extension of 5 or 7 years. Thus, this reform does not represent a net reduction, but instead defer the costs into the future (see more details in Chapter 3). Regardless the mechanism to cover the electricity system deficit, final electricity consumers will likely ultimately bear these costs.

When accounting for consumer power parity, the Portuguese residential electricity rates are the third highest across EU 28, only after Cyprus and Germany. The average residential electricity rate in 2013 was 0.26 euros[7]/kWh. For sake of comparison, the EU28 average was 0.20 euros/kWh in 2013, in the position 18th. If taxes are excluded, Portugal drops to the position number 16th, given that taxes and levies –which include the support for renewable feed-in tariffs, account for more than 40% of the total electricity tariff (EC 2014a). Fierce debate is ongoing in Portugal as a result of the high electricity prices and poor feed-in tariff designs: by March 2013,

[7] Eurostat reports these values in PPS/kWh, where PPS corresponds to euros after normalized by the power purchase parity of each country of the EU28.

the Secretary of State of Energy resigned from office short after he started exposing the potential increase in residential electricity prices and opened a public debate with EDP (Esquerda 2013; TVI24 2013; Dinheiro Vivo 2012b; Dinheiro Vivo 2012a; Garrido 2012; Ferreira 2012). Without a clear and open debate, it is likely that the costs associated with the feed-in tariff will keep increasing the system electricity deficit for long time.

2.7 Moving forward

Portugal has reduced its fossil-fuel power generation from 64% of total electric power demand in 1994 to about 53% in 2012 (DGEG 2014). The ambitious renewable capacity goals and the relative small expected increase in demand (DGEG & REN 2013) can create a surplus of electricity capacity and generation. The current national energy plan is to add more natural gas, cogeneration and renewable power capacity, including 4 GW of reversible hydropower and 2 GW of wind power, and phasing out the remaining two coal power plants by 2017.

The grid connection capacity with Spain is limited to 2,000 MW or less, but expected to be reinforced up to 3,000 MW (DGEG & REN 2013). There are no other anticipated connections with the rest of Europe in the short run, which limits the amount of Portuguese electricity that can be traded.

One of the key considerations as wind power grows further, are the effects on overall electricity market prices. Numerous factors affect the spot prices in the Iberian market. Since Portugal guarantees that all electricity produced by renewables needs to be received by the grid, this raises the issue of whether there will be hours with a surplus of electricity, resulting in exports to Spain.

When looking at monthly total electricity imports, we find a significant negative correlation between wind electricity generation and imports.

Portugal has achieved to be a wind leader mainly by implementing and continue to sustain a feed-in tariff mechanism. However, the country is now at a crossroad on how to continue to maintain its leadership position as a “green” electricity producer, while at the same time overcome the challenges of a country that underwent a tremendous recession, and where electricity prices are high when compared the to rest of the European Union – namely when one accounts for differences in purchasing power.

Wind generation currently accounted for 24% of total power generation in 2013 (REN 2014), and all existing wind parks connected since 1992 are receiving a feed-in tariff. The feed-in tariff is paid per monthly generation, and values wind power at around ¢10 per kWh. This incentive is paid for the beginning of operation of the park, and for 20 years thereafter.

Other countries had quite different feed-in or other incentive schemes. For example, Germany’s feed-in tariff included a digression rate from its inception, which encompassed reductions in the FIT as wind technology matured and became less expensive. Currently, the onshore wind FIT is $111/MWh for the first five years and $60/MWh for the next 15 years, and there is an annual digression of 1.5% by year of connection. Since January 2012 Germany included a premium mechanism, where instead of receiving the feed-in tariffs, the power producer bids directly in the energy market, and a premium is provided on top of that amount to the producer. The remuneration per kWh purchased by the grid is the same under the premium mechanism or the FIT. The difference is that the premium required the wind producer to enter the market directly or to establish a contract with a third party to sell its electricity (Brown 2013). Similarly, in Denmark, the current incentive relies on a market premium with a cap. The cap for wind parks financed by utilities is equal to $50/MWh, and the premium is given to 10 years. Currently, a wind park that was financed by EDP is receiving in Portugal a subsidy approximately two times larger than what would be the case in Denmark, and in addition does not incorporate any price risk because it never competes directly in the market.

In Italy, wind parks larger than 5 MW are awarded a connection license based on reverse auctions, i.e. those that bid the lower feed-in tariff. In Spain, as a results of a financial deficit associated with renewable incentives, the feed-in tariff was phased out for new projects starting January 2012, Also, since 2012, existing projects have retroactive cuts, which include that power producers have a limited number of hours for which can receive a special remuneration, the inflation adjustment is set to lower levels, they have to pay an access grid fee and there is no longer lifetime support (Brown 2013). The retroactive cuts were designed in order to guarantee a maximum return to investment equal to 7.5%.

In the U.S. there are federal and state incentives to renewable power. At federal level, there are investment grants and, until recently, production tax credits (PTCs). PTCs are credits over corporate taxes, given usually for a period of 10 years and approximately equal to $22/MWh (DSIRE 2011). The PTC was perceived as a critical incentive, and expired in January 2014. At state level, Renewable Portfolio Standards (RPS) established specific goals for amounts of renewables in the electricity generation mix by a specific target date. Currently 30 states and the District of Columbia have RPSs (Barbose 2012; EIA 2012) and require or use renewable energy credits (RECs). RECs are tradable certificates that represent the attributes of electricity generated from renewable sources and are used to demonstrate RPS compliance (Holt & Bird 2005). Wind projects can also pursue Power Purchase Agreements (PPAs), where an established price is set for periods ranging between 15 and 25 years.

Portugal has remained stagnant in the way they compensate renewable power generators and the wind support policy is out-of-date: wind feed-in tariffs in Portugal do not incorporate any financial risk or digression rate besides inflation, and are guaranteed for every unit of electricity produced. There are no power plants that have already been decommissioned despite being in operation for more than 20 years, favouring from new, detailed and hard-to-follow agreements in the legislation. All wind parks that are currently in operation have received feed-in tariffs since they connected to the grid, and are expected to keep receiving feed-in tariffs at least until December 2019, and up to December 2036. Portugal is the country with the longest feed-in tariff period that has already a mature wind power sector. From the electricity consumer's point of view, the high penetration of wind power increases electricity consumer prices.

Portuguese policy makers should be aware about the potential implications of electricity exports at moments with high wind resources, because the price paid for wind generation (i.e the wind feed-in tariff) is higher than the price received from electricity exports, which would result in a net cost for Portugal.

2.8 Supplemental Information

2.8.1 Main changes in the legislation, affecting wind power

Table 4 includes details on the Portuguese and EU renewable energy.

Table 4. Main E.U. Directives Decree-laws (DL) to incentivize renewable power in Portugal.

Decree-Law	Specifications	Feed-in tariff formula	Connection point granted
DL 189/88	Guaranteed payment for eight years No technology differentiation Limit up to 10 MW for total capacity installed for renewable energy generators (not for cogeneration) Over cost covered directly from the government Does not state directly that ALL production will be bought by the utility.	total = (0.8 x TP x p') + additional	Vague information in this respect
DL 182 and 186 of 1995: An independent entity for renewable electricity generation within the National Electrical System was established. Technical and feed-in tariff rules for cogeneration are also set.			
DL 313/95	The same as DL189/88 except that there is no limit for renewable energy installations (only hydro has a maximum capacity limit of 10 MW). DGEG will confer a license for exploration of the electrical grid for plants larger or equal to 10 MW and a regional entity will confer licenses for smaller plants.	Total tariff (€) = (0.8 x TP x p') + additional	Only specifies that it is necessary to ask information to DGE on the available connection points and that the power plant can start operation with the approval of DGE (>10 MW) or the regional entity in charge.
EU Directive 96/92/CE of the European Parliament and Council: Electricity production from renewable energy sources and cogeneration should have priority in the transportation and distribution grid.			
DL 168/99	Increase in the incentive Guaranteed payment for the first 12 years according to formula with three factors. Guaranteed payment after month 144 up to the date of the expiration of connection license ALL renewable electricity generation must be bought. The new formula can cover existing plants.	Total tariff (€) = f(fixed factor, variable factor, environmental factor, avoided transmission costs)	1. Ask for information on which points are available to connect. 2. Agreement of the connection point. When agreed, the point is put in reserved for 120 days. 3. Within those 120 days, ask for establishment and environmental license. Once the establishment license is granted, the producer has 18 months to start construction. 4. Construct 5. Ask for exploration license and start production.
EU Directive 2001/77/CE on the Promotion of Renewable Energy Sources. It states that Member States shall take the necessary measures to ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources. They may also provide for priority access to the grid system of electricity produced from renewable energy sources. With this directive, the E.U. indicative non-binding target was set to achieve 12% of gross domestic energy consumption and 22.1 % of gross electricity consumption to come from renewable sources by 2010. Portugal agrees to reach 39% of its electricity production from Renewable Energy Sources by 2010.			
DL 312/2001	Establishes the necessary grid updates to reach the national renewable electricity target.	Total tariff (€) = f(fixed	Two mechanisms described:

DL 339/2001	All procedures to get a connection right must be transparent and public. States that the grid extension/update costs that RE producers had to cover to connect to the grid must be share from now on between the grid operator and the producer, and these costs will be supported through the consumer tariffs. The company that has the concession for the operation of the grid (grid operator) and the distribution company are in charge of planning the extension/update of the grid, which is submitted and approved by the regulator (ERSE). Differentiation by technology in the formula (Z factor). 2.5% payment to the Junta de Freguesía.	factor, variable factor, environmental factor, technology used, avoided transmission costs)	I. Direct procedure to ask for a connection right: individual or public tender. 1. Ask for information (if not enough capacity available pay for financial cost of anticipation of the construction) 2. Ask for environmental license. 3. Put all licenses together and ask for connection right 4. Ask for establishment license (to DGEG and requires environmental license). 5. Ask for exploration license (FIT is agree here) II. Apply for a connection right under a public tender under specific criteria
Directive 2003/30/EC of the European Parliament and of the Council on the promotion of the use of biofuels or other renewable fuels for transport.			
DL 33A-2005	FIT for 15 years or 33 GWh per MW installed.		
2006 Commission communication: 'Action Plan for Energy Efficiency: Realising the Potential', sets a 20% improvement in energy efficiency by 2020. This document was endorsed by the European Council on 2007, and by the European Parliament on 2008.			
DL 90/2006	Details on the way the FIT is funded through consumers, establishing a differential electricity tariff for consumers on low, medium and high tension.		
2007: 'Renewable Energy Roadmap — Renewable energies in the 21st century: building a more sustainable future'. This is a Commission communication that shows that a 20% target for the overall share of energy from renewable sources and a 10 % target for energy from renewable sources in transport would be appropriate and achievable objectives by 2020. Reaffirmed by the European Council. **EU 20-20-20 Energy Package:** 1. Binding target to reduce GHG by 20% compared to 2020 projections. 2. Binding target to increase to 20% the portion of final EU energy consumption that comes from RES. 3. Non-binding target to improve energy efficiency by 20% compared to 2020 projections.			
DL 225/2007	Details on the environmental license to shorten administrative procedures and allowed an increase in 20% increase in the capacity of projects that have received a connection license.		
EU Directive 2009/28/CE on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77EC and 2003/30/EC. The targets established are to achieve 20% of final gross energy consumption coming from renewables and 10% of transport energy consumption coming from renewables (including biofuels). Portugal's target for share of energy from renewable sources in gross final consumption of energy by 2020 was set to 31%, and the transport target was equally set to 10% to all member states.			
2010: Portuguese Cabinet Resolution No. 29/2010, which approved the latest National Energy Strategy (NES 2020). Continuous to attribute a pivotal role to renewable energy in the energy strategy.			
2010: Climate Change Action Plan (NREAP) of Portugal presented to the European Commission. Portugal committed to: 1. Achieve 31% of the gross final energy consumption, 60% of the electricity produced and 10% of the energy consumption in the road transport sector will be derived from renewable sources in 2020. 2. Reduce energy dependence based on the consumption and importation for fossil fuels to around 74% in 2020. 3. Reduce the balance of energy imports by 25% (around 2 million euros), i.e. reduce imports by an estimate 60 million barrels of oil. 4. To consolidate the wind industrial cluster creating 100,000 new jobs in addition to the existing 35,000 by 2020.			
DL 35/2013	FIT for 20 years or 44 GWh per MW installed. Payments from the wind producers back to the SEN between February 2013 - December 2019 and extension of existing FIT for 5 to 7 years.		

2.8.2 Details on the feed-in tariff parameters for the 1999, 2001 and 2005 formulas

Table 5 includes the changes in the parameters of the Portuguese feed-in tariff formula.

Table 5. Values used in the formula to compute the tariffs for wind in Portugal.

Factor	DL 168/99	DL 339/2001	DL 33-A/2005
Z	Does not exist	Z = 1.7 between 0 and first 2,000 hours, 1.3 between 2,000 and 2,200 hours, 0.95 between 2,200 and 2,400 hours, 0.65 between 2,400 and 2,600 hours and 0.4 for more than 2,600 hours.	Z = 4.6
PF (Fixed factor)	=1090 PTE/kW x coef x POT =$90/kW x coef x POT coef = 0.22 to 0.3 POT=kWh generated over *m*/ hours in *m*	Not mentioned¥	=5.44 euros/kW x coef x POT =$80/kW x coef x POT coef = 0.25 to 0.33 POT=kWh generated over *m*/ hours in *m*
PV (Variable factor)	5 PTE/kWh ($0.036/kWh*) x kWh generated	Not mentioned¥	0.036 €/kWh ($0.044/kWh) x kWh generated
PA (Environmental factor)	370 g/kWh x 0.015 PTE/g* (or $109/ton**) x kWh generated	370 g/kWh x 0.015 PTE/g* (or $109/ton**) x kWh generated	No reference to the 370 g/kWh¥ x 2 x 10-5 €/g (or $25/ton) x kWh generated
T	0.625 for off-peak hours and 1.25 for peak hours Formula valid for 12 years	0.625 for off-peak hours (10 pm-8am) and 1.25 for peak hours Formula valid for 12 years	0.625 for off-peak hours and 1.25 for peak hours Formula valid for 33 GWh/MW or 15 years. Since 2013, valid for 44 GWh/MW or 20 years.
Trans	Between 1.015 – 1.036	Between 1.015 – 1.036	Between 1.015 – 1.036

All dollar values given as $2005 constant values. *Conversion rate in 1999 (assumed to be the same for 2000): 1€=200.5 PTE.
**ton: thousand kg., ¥ Not mentioned meaning does not change and remains as previous decree/law.

2.8.3 Understanding Regional Wind Power Diffusion

Given the economic, geographical and cultural regional differences, we explored the correlation between variables at the municipality level (called NUTS III level in the EU system) from 1992 to 2010 that could help understand the regional wind diffusion process in Portugal (data from INE 2011; INEGI 2011). As expected, annual cumulative wind power is not significantly correlated with annual electricity consumption or total annual electricity production, i.e. wind capacity is not necessarily installed close to demand or to other generation capacity[8]. On the other hand, wind is positively correlated with hydro production at a 0.1 significance level. Even though pumped-hydro can serve for wind electricity storage we did not controlled for hydropower plants with pumped-hydro storage capacity. This correlation does not necessarily mean that wind parks have pumped-hydro storage capacity associated, but that new power plants are built closed to existing connection points used by already existing power plants. In fact, up to 2010, Portugal had only six hydropower plants with installed pumped-hydro capacity, accounting for approximately 1,100 MW (Ministério da economia e do emprego et al. 2013). However, the national goal is to achieve about 4,000 MW and 5,000 MW of pumped-hydro capacity by 2020 and 2030, respectively that will help to achieve the 2030 wind power goal by serving as storage capacity for wind electricity generation. Lastly, we found that annual regional cumulative wind power negatively correlated with income at 0.01 significance level reflecting that wind capacity installment might be relatively more attractive in poorer municipalities.

About 10% of the territory of Portugal is environmentally protected, i.e. not suitable for wind power development. The North and Center regions comprised almost all wind power capacity installed by 2010. At the territorial division (NUTS II) shown in Table 6 the share of environmental protected area is not significantly correlated with the share of wind cumulative capacity. Wind diffusion did not happen necessarily in regions with more suitable area for construction.

[8] Because the average size of the regions considered is 3,200 km^2, wind power can in fact be considered to be 'close' to demand or other electricity production centers, compared to other countries. For instance, the U.S. state of Texas has an area of 700,000 km^2, more than 200 times the size of the average Portuguese NUTS II region.

Table 6 Distribution of protected areas and wind cumulative capacity in the five NUTS II regions.

Region	Area (share of area in Continental Portugal)	Percentage of protected area in 2009[9]	Wind Cumulative capacity	Wind cumulative capacity (% of national)
North	24%	8%	1511 MW	34%
Center	31%	9%	2458 MW	60%
Lisbon	5%	4%	103 MW	2%
Alentejo	33%	9%	47 MW	1%
Algarve	7%	0.4%	140 MW	3%

2.8.4 Variables analyzed at municipality level, and correlation with wind cumulative capacity.

Table 7 shows basic statistics for the variables studied (columns 2 to 4) and the correlations with cumulative wind capacity (column 5).

Table 7 Summary statistics for the variables included in the regional analysis, at municipality level.

Variable (units)	Mean (standard deviation)	Min-Max	Period and source	Correlation with Annual Cumulative Wind Capacity, MW. (p-values)
Annual Cumulative Wind Capacity (MW)	33 (83)	0-563	1992-2010 Inegi, e2p	NA
Annual Electricity consumption (kWh)	1.4×10^9 (1.66×10^9)	$7.5 \times 10^7 – 8.9 \times 10^9$	1994-2009 INE	-.03 (.46)
Annual Total electricity production (kWh)	1.64×10^9 (2.44×10^9)	$39-1.1 \times 10^{10}$	1994-2009 INE	.0475 (.4815)
Annual Hydro electricity production (kWh)	3.5×10^8 (6.2×10^8)	$0-3.8 \times 10^9$	1994-2009 INE	.1267* (.06)
Average monthly Income ($)	812 (135)	587-1366	2004-2009 INE	-.1986¥ (.0098)
Protected Areas (% of area of the region)	9 (10)	0-53	2007-2009 INE	-.1012** (0.0196)

*Significant at 10% level, **Significant at 5% level, ¥ Significant at 1% level.

The significant variables provide insight in the potential impact that these had in the allocation of wind power in Portugal. An econometric model would be needed to make further conclusions,

[9] 8% of Portugal is protected area. This includes: natural park, national park, natural reservoir, protected landscape, natural monument and classified area (INE 2011)

and the average wind speed at municipality level (not publicly available) should be included. Other variables, such as investment costs should be included if vary across regions.

Nevertheless, the significant positive correlation between wind cumulative capacity and hydro production reflect that wind power might have being built in regions with already hydro capacity installed. In addition, the significant negative correlation between wind cumulative capacity and monthly income reflect that wind power might have been relatively more attractive to poorer regions due to the revenue that the municipality receives from wind production. Lastly, the significant negative correlation between wind cumulative capacity and percentage of environmentally protected areas show that these limit the availability of land for wind projects.

3 Chapter 3: Economic analysis of the profitability of existing wind parks in Portugal

Paper accepted in Energy Economics, June 2014.

3.1 Abstract

Discussions on the appropriate policy design and level of incentive to promote renewable energy adoption and meet the 20/20/20 goals have spurred recently in the European Union. These discussions are also ongoing in Portugal, namely in what concerns the level and duration of feed-in tariffs that should be provided to independent power producers. This, in turn, raises the question of whether the past feed-in tariff levels were well designed to achieve the goals of a larger penetration of renewables in the Portuguese grid. The policies to induce wind adoption have led to a growth in wind installed capacity and share of electricity generated by wind in Portugal, but questions arise on their cost-effectiveness and whether alternative policy designs would have led to the same goal. In this work, we estimate profits made by wind independent power producers for wind parks that were connected in Portugal between 1992 to 2010, and conclude that the feed-in tariffs have overcompensated some wind power producers. We also discuss the recent changes in feed-in tariff legislation published in February 2013 and estimate the expected costs of the introduced changes.

3.2 Introduction

Global wind power increased by 200 GW in the past five years. Just in 2013, the industry grew by 12.5%, due mostly to an increase in installed capacity in China and in Canada (GWEC 2014). Around the world, several countries so far have or had renewable tariff schemes. However, the design and implementation of such schemes varies substantially across countries both in terms of design and amount (Mendonça 2007; Mendonça et al. 2009). For example, in Spain, a renewable electricity producer could choose between receiving a fixed price or a bonus on top of the spot electricity market price; in Denmark the tariff would correspond to a bonus on the top of the electricity market price; and in Germany the incentive included a fixed base tariff to which a bonus could be added (EC 2013a).

Portugal, too, has implemented mechanisms to incentivize the production of electricity from renewable sources. Today, wind accounts roughly for 20% of electricity generation. Wind power has been added to the grid since the late 1980ies: since 1988 Portugal has a feed-in tariff (FIT) system, i.e., a guaranteed price for electricity generated from several renewable energy sources (Diário da República 1988), including wind. The wind FIT scheme in Portugal was applied since the construction of the first wind park in 1992, and as of February 2013, FITs are guaranteed for the first 20 years of production or until the production of the wind park reaches 44 GWh per MW of installed capacity (Diário da República 2013).

In Portugal, FIT values are defined according to a formula established by legislation. The amount is computed every month by the energy regulator (ERSE) for each independent power producer (IPP) according to several factors, such as inflation, avoided costs and environmental benefits.

The Portuguese wind policies and associated legislation have been changing over time, and so has the formula used to compute the monthly FITs provided to IPPs for wind and for other energy sources, and therefore the level of incentive that independent power producers obtained. Figure 11 shows the four main laws where FITs formulas changed, as well as the reported average annual national FIT for wind over time.

As shown in Figure 1, the annual national average FIT for wind ($/MWh) decreased from 1992 to 1999 (all costs and benefits throughout the paper are in dollars of year 2005. The euro-dollar exchange rate used was 1.24 euro/$ for year 2005). In 1999, FIT values started to include environmental benefits that arise from avoided construction of additional fossil fuel power plants. Since 1999 until today, the FIT formula assumes that the carbon intensity of the Portuguese grid is of 370g CO_2 per kWh (Diário da República 1999) and that the externalities associated with CO_2 are valued at $20 per metric ton of CO_2 (Diário da República 2005).

In 2001, FIT started to differ by technology. Before 2001, a kilowatt-hour generated from solar energy received the same payment as a kilowatt-hour generated from wind energy (Diário da República 2001b). This change let to an increase in wind FIT of approximately 20%[10]. Also in 2001, Decree-Law 312/2001 specified two public procedures for wind power producers to have connection rights: (1) a direct procedure in which parks individually ask for a connection license when the Directorate of Energy (called Direcção Geral de Energia e Geologia, or DGEG, in Portugese) establishes available connection points, and (2) a public tender in which specific criteria apply to grant connection licenses. About 3,000 MW were granted up to 2005 under the 'direct procedure' specified in 2001, and 1,900 MW were allocated between 2006 and 2008 according to the 'public tender procedure' that opened in 2005. In addition, Decree Law 339/2001 established that wind IPPs would pay 2.5% of the total revenue obtained from power generation to their respective municipality (Diário da República 2001b).

In 2005, the wind FIT was established for either 15 years or until producing 33GWh per MW of capacity installed (Decree-Law 33A/2005). Oddly enough, the 2005 legislation also provided

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[10] The FIT formula in 1999 and 2001 was the same except for a coefficient to differentiate renewable energy technologies. Assuming a capacity factor of 0.20, a given wind park would receive 23% more under the formula established in 2001 than under the formula established in 1999.

that all projects connected before 2005 had an additional 15-year period of FIT starting February 2005, regardless the number of years they had been already operating and under the FIT mechanism. Therefore, according to Decree-Law 33A/2005, only by January 2020 will some wind parks be ending their FIT period.

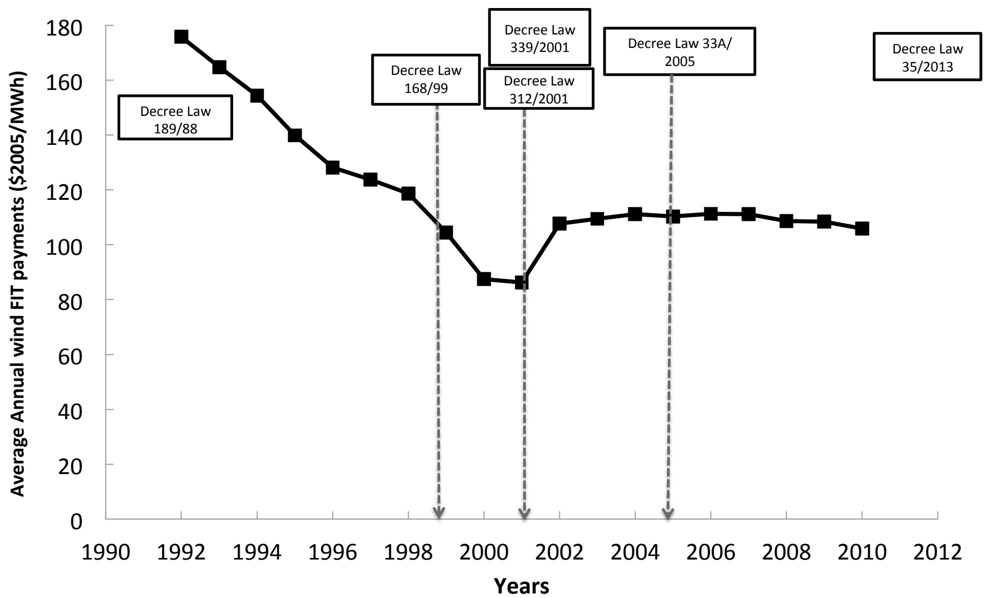

Figure 11. Average annual wind FIT in Portugal over 1992-2010 ($2005/MWh). Constructed using data from (ERSE 2011).

The decree law in 2005 (33A/2005) established that after a 15-year period where IPPs are provided with a feed-in tariff, wind parks would start receiving the average annual spot electricity market price plus the value of green certificates[11] those green certificates are available. If a green certificates scheme is not available when the FIT period ends, the FIT is to be extended for five additional years. Since 2012, wind IPPs, which are predominantly represented

[11] A green certificate is the name given in Europe to U.S. renewable energy certificates (RECs). In Portugal, these are certificates that are issued by the Grid Operator (REN) and can be traded in a separate market, leading to additional profits to renewable energy generators. Nevertheless, wind parks under the FIT system cannot trade green certificates.

by the Portuguese Renewable Energy Agency (APREN), have been negotiating with the Energy Regulator (Entidade Reguladora dos Serviços Energeticos, or, ERSE, in Portuguese) a new remuneration scheme for the subsequent years. The motivation comes from the need to cut the National Electricity System (SEN) deficit, and is reinforced by the "Memorandum of understanding on specific economic conditionality" (MoU) issued by the Troika (European Commission, International Monetary Fund and European Central Bank), which expresses the need to limit the policy costs of renewables (EC et al. 2013; EC 2013b).

Recently, the Ministry of Economy and Employment called upon a redesign once again the FIT scheme and claimed that "not all the expenditures associated with the support of renewable energy generation technologies have been passed on to electricity consumers" (Diário da República 2013), which could lead to an increase of the deficit of the National Electricity System (SEN) (Diário da República 2013). Negotiations between the regulator and stakeholder groups resulted in the publication of a new legislation in 2013 that aims at reduce urgently part of the electricity system deficit. The 2013 legislation includes an annual payment to the regulator, and in exchange offers the opportunity to increase the period of the FIT payments. There are two levels of possible annual payments from the wind IPPs back to National Electricity System (SEN): a 'low payment' equal to $6,700/MW-installed and a 'high payment' equal to $7,500/MW-installed, either of which are paid annually for eight years. The 'low payment' offers a FIT extension of five years and the 'high payment' offers a FIT extension of seven years[12]. This extension period starts in 2020 for old parks (connected on or before 2005). Parks connected after 2005 will keep receiving the current FIT of approximately $105/MWh for 20

[12] The terms 'low payment' and 'high payment' are not textual from the legislation, but are used by the authors to describe better its details.

years or until the park produces 44 GWh of generation per MW of capacity installed –counted from the year of connection, instead of 15 years or 33 GWh, as previously established in 2005 legislation. Thus, the option to further extend the FIT for five or seven years in exchange of payments to the SEN is as well available to new wind parks, and the extension period starts counting between 2026 and 2029 depending on connection year (see Figure 12 for details). The FIT offered for the additional period is designed to equal the level of spot electricity market prices. In any case, the levels of incentives are designed so wind power producers receive higher revenue than the payment they need to make back to the regulator. For instance, assuming a capacity factor of 0.20 and the low FIT offered of $85/MWh a wind IPP will receive approximately $150,000/MW per year of FIT extension (or $44,000/MW compared to a $60/MWh electricity price), and will have to pay $6,000/MW back to the regulator.

Wind IPPs can also choose not to receive the FIT extension of five to seven years, in which case they will not need to make the annual payments back to the National Electricity System. Thus, if this option is chosen, parks connected on or before 2005 will start receiving the spot electricity market price by January 2020. Similarly, wind parks connected between 2006 and 2010 will start receiving the spot electricity market price between 2026 and 2030 respectively, assuming the limits of production are not met at that time[13]. Figure 12 highlights different strategies that wind IPPs can consider as a result of Decree-law 35/2013.

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[13] 33GWh and 44GWh per MW installed corresponds to a capacity factor of 0.25 over 15 and 20 years, respectively. Because the national average capacity factor over 2006-2010 was 0.23 we assume in our analysis that the production limits are never met, and the FIT period is determined by years of production.

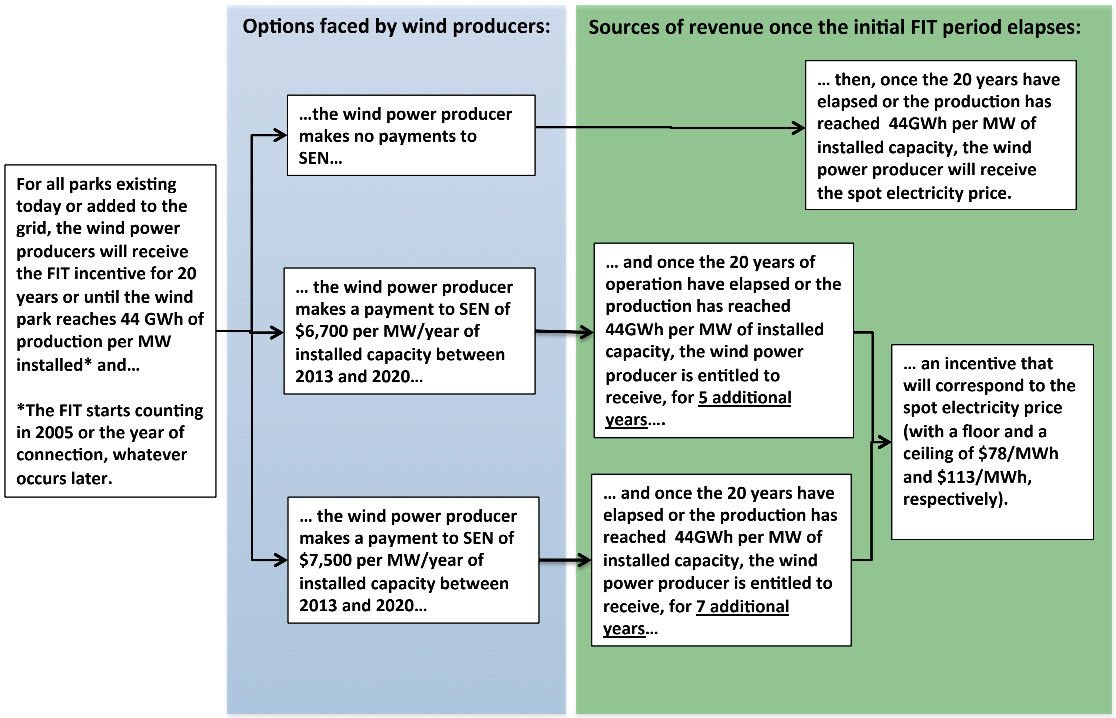

Figure 12. Possible remuneration schemes currently available for existing wind parks in Portugal.

Total cumulative spending in the form of wind FITs between 1992 and December 2010 is reported to have been approximately 4.1 billion dollars (ERSE 2011), or about 1.5% of national Portuguese annual gross domestic product (GDP) (WB 2013), and slightly less than 1% of Portugal external debt (Banco de Portugal 2013).

The energy policy for wind included several goals and requirements for participants in this market. For example, in the public tender of 2005 one of the award criterions was to use wind energy to leverage the creation of a new industrial sector through an obligation to provide investment and employment in some of the country's less favored regions, to encourage the transfer of technology to Portugal from abroad and to create a new source of export of goods, limiting the import of wind turbines (ENEOP 2009). ENEOP, Eólicas de Portugal SA, won the first and the largest phase of this bid, and it reports that the criterions established by the public tender for job creation, R&D funding allocation and the creation of an industrial cluster were met (Eneop 2009b; Eneop 2009c; Eneop 2009a). More details regarding each of these aspects are provided in the SI.

In Figure 13, we show the multiple extensions provided over time to IPPs for the period over which they are entitled to receive FITs. For example, parks connected in 1992, were originally expected to stop receiving FIT incentives after 12 years, i.e., by 2004. However, with the 2005 law the incentive was continued until 2012 (the expected last year of operation of those plants). Similarly, plants connected in 2006 were originally expected to receive the FIT incentive for 15 years, i.e., until 2021, according to the 2005 law. By 2013, however, a new law extended the period to 20 years, and thus, those plants connected in 2006 will be receiving FIT incentives until 2026. Moreover, after that period they can choose to extend for another five or seven years the incentive in exchange of payments to SEN for eight years.

Despite the positive impact in terms of greening the Portuguese electricity grid, there is still an open question of whether the mechanisms and incentives set in place could have been designed in a different way, while achieving the same amount of electricity produced from wind. In particular, the issue arises of whether the design of the FITs was such that IPPs were over-compensated, and the same results could have been achieved at much lower costs to Portuguese consumers. This paper has two goals: to estimate the profits made by wind IPPs that connected to the grid from 1992 to 2010 (the most recent year for which investment data is available) and to make recommendations on how to design a policy that could provide similar outcomes while reducing public spending in the future.

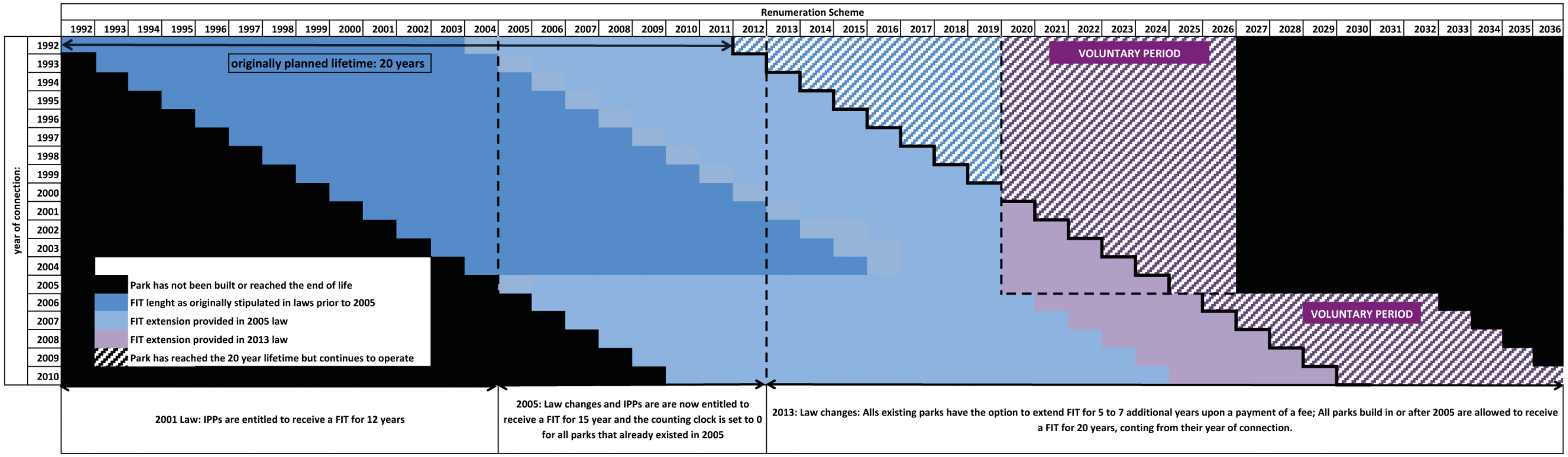

Figure 13. Extensions of FIT remuneration period by several Portuguese laws over time.

3.3 Methods

We assess the profitability of wind energy in Portugal in two ways: by computing the net present value (NPV) of all wind projects and by comparing the annualized revenue with the levelized costs of electricity (LCOE) for parks added each year from 1992 to 2010. Our analysis ends in year 2010 as that the most recent year of publicly available data on investment costs. While additional capacity from wind will be added in Portugal in the near future, in this paper we limit our analysis to built capacity as of December 2010.

Both NPV and the comparison between annualized revenue and LCOEs provide similar messages. For example, in the NPV analysis, we estimate the NPV for different market clearing prices *p* received by the wind IPPs after the FIT period is over. In the annualized analysis we estimate the *p* that would make the wind park to break even. We aggregate projects by year of connection, and we use the annual national average capacity factor to estimate wind generation.

3.3.1 Levelized annual costs and benefits

We assess the equivalent annualized profits (in \$2005/MWh), i.e, annualized revenue minus annualized costs. Annual revenue corresponds to the FIT value in the years where the IPPs have access to a FIT (\$2005/MWh), and to the spot electricity price *p* in the years thereafter. Annual costs correspond to the levelized costs of electricity, or LCOEs. Thus, annualized profits (\$2005/MWh) for wind farms installed in year i, AP_i, are computed as follows:

$$AP_i = AR_i - AC_i$$

$$AR_i = \frac{\left[\sum_{k=i}^{i+T} \frac{((1-muni)\times FIT_k)\cdot gen_k}{(1+r)^{k-i}} + \sum_{k=i+T+1}^{lifetime} \frac{p_k \times gen_k}{(1+r)^{k-i}}\right] \cdot CCR}{\sum_{i=y}^{lifetime} gen_i} \tag{1}$$

$$AC_i = \frac{I_i \cdot CCR + O\&M_i}{\sum_{k=i}^{lifetime} gen_k}$$

Where AR_i and AC_i are the annualized revenues and costs for wind parks installed in year i (\$2005/MWh), and gen_k is the annual electricity generation (MWh) in year k by parks installed in year i. FIT_k is the average annual national FIT payment in year k (\$2005/MWh), paid for period T. *muni* (in \$2005/MWh), represents the payments that wind IPPs have to make to the municipality, which corresponds by law to 2.5% of total revenue during the FIT period, and p_i is the spot electricity market price (\$2005/MWh) that wind producers receive after the FIT period is over. (Diário da República 2005; Diário da República 2013). *CCR* is the capital recovery rate, $\left(\frac{r}{1-(1+r)^{-lifetime}}\right)$, where r is the discount rate. We assume a discount rate –or weighted costs of capital (WACC), equal to 10% based on the European reported values in the literature (IRENA 2012; IEA 2010b; IEA 2009), and consistent with the rates approved by the Public Utility Commissions (PUCs) of return on equity reported in the U.S. (Ketchum & Kim 2013).

I is the total investment costs (\$2005) incurred by projects connected in year y, including foundation, road, land and grid connection. We assume a one year lag time to take into account construction time, i.e. projects connected in 1993 incur investment costs of 1992. Due to lack of available data for Portuguese investment costs, we used Danish investment costs from 1992 to 2002 (EWEA 2009b) and Portuguese investment costs from 2003 to 2010 (IEA 2010a). While there is uncertainty associated with these values, there is a correlation of 0.95 of Danish and Portuguese investment costs for years where there is overlapping data, i.e., from 2003 to 2006, which justifies the use of Danish wind investment data. It is important to notice that real Portuguese investment costs might be higher than Danish' for 1992-2002 because Danish wind industry was more mature by the 90's compared to Portugal. Nevertheless, because by 2002 there was very little wind capacity installed in Portugal, we are confident that an underestimation of Portuguese costs from 1992 to 2002 does not affect the overall results. However, the correlation for investment costs only exists for the overlapping period of four years, and so it may be the case that we are under or over estimating the costs for Portugal in our analysis. Given this key limitation, we perform a sensitivity analysis to test our results taking into account higher investment costs over all the period analysed. *O&M* are total annual maintenance and operation costs, assumed to be constant (in $2005 values) over the lifetime.

3.3.2 Net present value

We supplement the annualized analysis with the net present value for wind independent power producers for the poll of wind plants in operation between 1992 and 2010, by year *i* in which they were installed. It is computed as:

$$NPV_i = \frac{\sum_{k=i}^{i+lifetime} \frac{TR_k - TC_k}{(1+r)^{k-i}}}{\sum_{k=i}^{i+lifetime} gen_k} \tag{2}$$

Where NPV_i represents the net present value over the lifetime (*lifetime*) for all parks installed in year *i* (in $2005/MWh), TR_k is the total revenue in year *k*, and TC_k is the total cost in year *k*. TR_k is given by (FIT_k x gen_k) during the years where wind parks are entitled to receive FITs, and to the spot electricity price *p* otherwise.

We normalize the NPV by the amount of electricity generated by the existing wind parks connected in year *k* over their lifetime, thus gen_k is the amount of electricity generated by wind parks connected in year *k*. The results for the NPV analysis are included in the Supplementary Information (SI).

Total costs include investment costs, O&M fixed costs (in $2005 values), and the municipality payment equal to 2.5% of total revenue received.

3.3.3 Scenarios

The scope of this paper is to focus only on existing wind parks, i.e., parks that were in operation by 2010. We assume that parks have a 20-year lifetime. From 1992 to 2010, we use historical data on wind parks location, average annual capacity factors, costs and FIT levels. As explained in the previous section, underlying law followed by IPPs was recently changed in Portugal, such that parks connected on or before 2005 can choose to extend the period they receive a tariff by five or seven additional years at the end of their 15-year FIT period, as long as they make a payment now back to the regulator as a way to reduce the current funding deficit Portugal endures in the electricity system. Since the regulatory system covering wind IPPs has been regularly updated and changed over time, we consider four scenarios for the period 2013 to 2029 (last year of generation for the newest parks considered). Specifically, we assume several ranges of values for the spot electricity prices p wind power producers will receive in the years in which they are operating but not entitled to receive a FIT. This situation starts occurring in January 2020 for the older wind parks, when their 15-year FIT period expires. We also consider potential future revisions to the current law by assessing the consequences of shortening the period that wind IPPs are currently entitled to receive the FIT. In addition, we consider a fifth scenario in which we assess the relevance of the recent changes under Decree-Law 35/2013 versus the previously ongoing legislation. In all cases, for years before 2010, we use historical data. For years 2011 and onwards, we consider the following scenarios:

- **Scenario 1**: Scenario considers a case where Portugal would have decided to keep their 2005 law. This would mean that all parks would have 15 years worth of incentives, starting counting in 2005, no matter for how long they had already been receiving incentives. This scenario shows what would have occurred if the government had decided to not implement the 2013 legislation.
- **Scenario 2**: Same as scenario 1, but assuming the government had decided to shorten the time of FIT incentive from 15 years to 12 years. This scenario highlights wind parks that can end the FIT and be competitive in the next few years. Projects that have received already a FIT for more than 12 years would then be having their FIT incentives ending now –i.e. by December 2013.
- **Scenario 3:** Assume the FIT system would end at the beginning of 2014 for all wind parks, regardless year of connection. This scenario shows whether projects would be profitable if they enter now the Iberian competitive electricity market.
- **Scenario 4:** Since the average national FIT paid over the past five years is $105/MWh, we include a scenario in which a fixed FIT equal to $105/MWh is offered to all wind parks for 15 years. This scenario highlights a simpler approach that a policy maker could use instead of the current FIT formula system: a fixed tariff and fixed period.
- **Scenario 5:** We simulate the effects of the legislation established in 2013, in which FIT period is extended in exchange of a "payback payment" from the wind IPP to the SEN, and we assess how the new changes in the policy impacts profitability of wind parks. All wind parks are considered to incur extra investment costs in December 2019 to operate

over all the period analysed, as their lifetimes are extended. These costs are assumed to be 35% of 2010 reported total investment costs (IEA 2010a), representing the replacement of gearbox, transformer and generator -or 50% of total turbine costs (EWEA 2009b). Further assumptions are: payment of extra investment costs over five year period, 10% discount rate and fixed O&M costs of $5/MWh.

For all the scenarios, after the FIT or extended incentive period is over, we assume IPPs are required to be players in the market, and receive the spot electricity price *p*. Spot electricity market price, treated as a parameter: $0/MWh, $30/MWh, $60/MWh, $90/MWh and $105/MWh.

3.4 Data

Portugal's first wind turbine was installed in 1992. By 2010, Portugal had approximately 4,000 MW of wind capacity installed (ERSE 2011). Figure 14 shows wind capacity added in the country between 1992 and 2010. By December 2001, there were less than 100 MW installed in wind capacity, distributed in 7 of the 28 NUTS II[14] regions of Continental Portugal. In contrast, by 2010, Portugal had 40 times more wind capacity installed across 22 of the 28 continental regions. Portugal had by December 2010 approximately 0.4 kW of wind power installed per capita (ERSE 2011; INE 2011), whereas other wind power leaders, such as Denmark, Germany,

[14] The European Commission classifies the European Territory according to the NUTS classification (Nomenclature of territorial units for statistics). According to NUTS I, Portugal is divided in three regions (Continental, Azores and Madeira). According to NUTS II, Portugal is divided in seven regions (Regional Coordination Commissions and Autonomous regions). According to NUTS III Portugal is divided in 30 municipalities. Since our analysis is for Continental Portugal, we cover 28 municipalities.

U.S. and Spain, which had by 2010 approximately 0.7 kW, 0.3 kW, 0.1 kW and 0.4 kW of wind power installed per capita, respectively (AWEA 2013; AEE 2013; DEA 2011; BWE 2013).

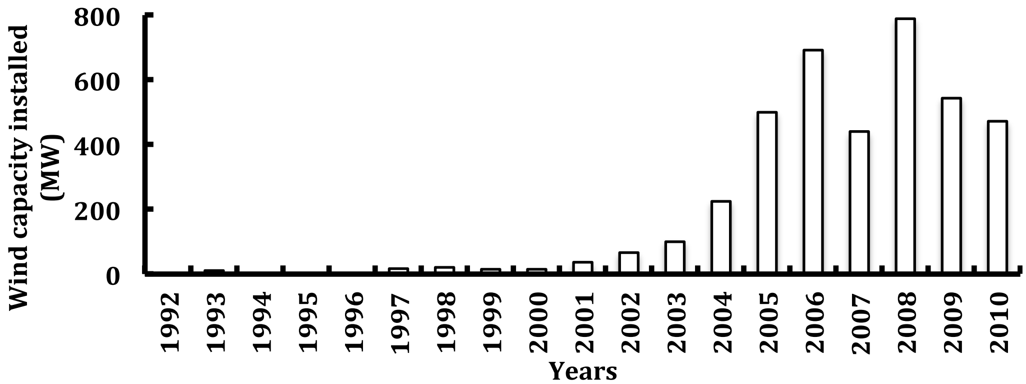

Figure 14. Portuguese wind power capacity added annually (MW) between 1992-2010 (ERSE 2011).

Total Portuguese wind investment costs (including turbine and foundation costs) are reported from 2003 to 2010 by IEA 2010. For lack of better data, we use data from 1992 to 2002 from Denmark since the correlation in the overlapping period 2003-2006 is 0.95. Figure 15 shows investment costs for Denmark from 1990 to 2006 and for Portugal from 2003 to 2010. Projections of the European average wind investment costs are also shown in Figure 15, but were not used in the analysis due to the large discrepancy when compared with Portugal data for the overlapping years. The variability of data reported by the IEA on Portuguese wind investment costs is likely due to a shortage of wind turbines in years of high demand (between 2006 and 2010) and a high FIT that could motivate wind turbine manufacturers to charge higher prices (ERSE 2012a).

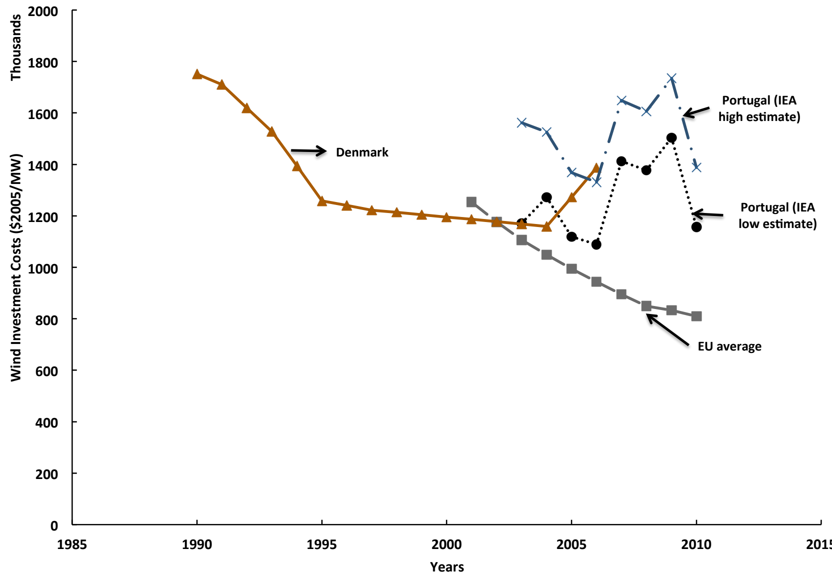

Figure 15. Wind Investment Costs in Denmark (EWEA 2009b), Portugal (IEA 2010a) and for the EU projected average (Zervos 2003) between 1990-2010.

We use an average annual national capacity factor to estimate generation of all wind parks connected in a particular year due to lack of data availability of capacity factor by location. To the extent of our knowledge, there is no public available data from the same source on wind capacity installed and wind power generation by region and across time. Only national data for generation and capacity installed is publicly available, as shown in Figure 16.

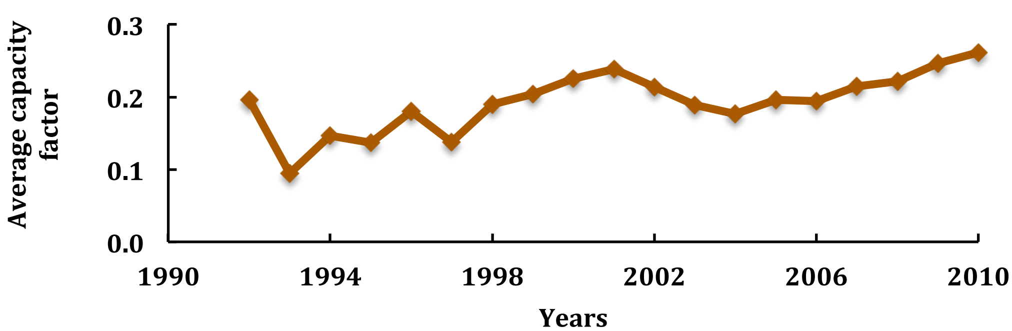

Figure 16. Average capacity factor for wind farms in Portugal from 1992 to 2010 (ERSE 2011).

We assume constant and equal O&M costs across all wind parks, regardless their year of connection because of lack of data, and test that assumption in the sensitivity analysis. Wind maintenance companies in Portugal report O&M costs[15] as low as $8,000/MW per year (Anon 2012), representing average maintenance costs of $4/MWh. Other estimates range from $9/MWh to $27/MWh (reviewed sources: (EWEA 2009b),(NREL 2012), (IRENA 2012)). Reductions of 40% in O&M costs are reported between 2008 to 2012 in a study covering 38 developers and service providers in more than 20 markets in Europe (BNEF 2012; EurObserv'ER 2012). We assume $5/MWh, but include a sensitivity analysis for which O&M costs are as high as $25/MWh for all wind parks over all their lifetimes to cover all possible levels.

3.5 Results

Unless otherwise noted, basic assumptions used for these estimates are 10% discount rate, 20-year lifetime, $5/MWh of O&M costs and a loan payment over a 20-year period.

3.5.1 Annualized flows, by year of connection

Figure 17 shows annualized revenues and costs over the wind parks lifetime for parks connected for each year between 1992 and 2010, by year of connection. Parks with LCOEs higher than the annualized revenues would have economic losses. For instance, under the assumptions we used for this simulation, that appears to be the case for parks connected in 1992 and 1993. However, it is unlikely these projects have not recover their costs: in our simulations we assume 10% discount rate and annual capacity factors equal to average national. Lower discount rates lead to

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[15] All values reported were translated into $2005 constant values.

positive NPVs for these early projects (see Sensitivity Analysis). In the Supplementary Information we provide details on the NPV by connection year.

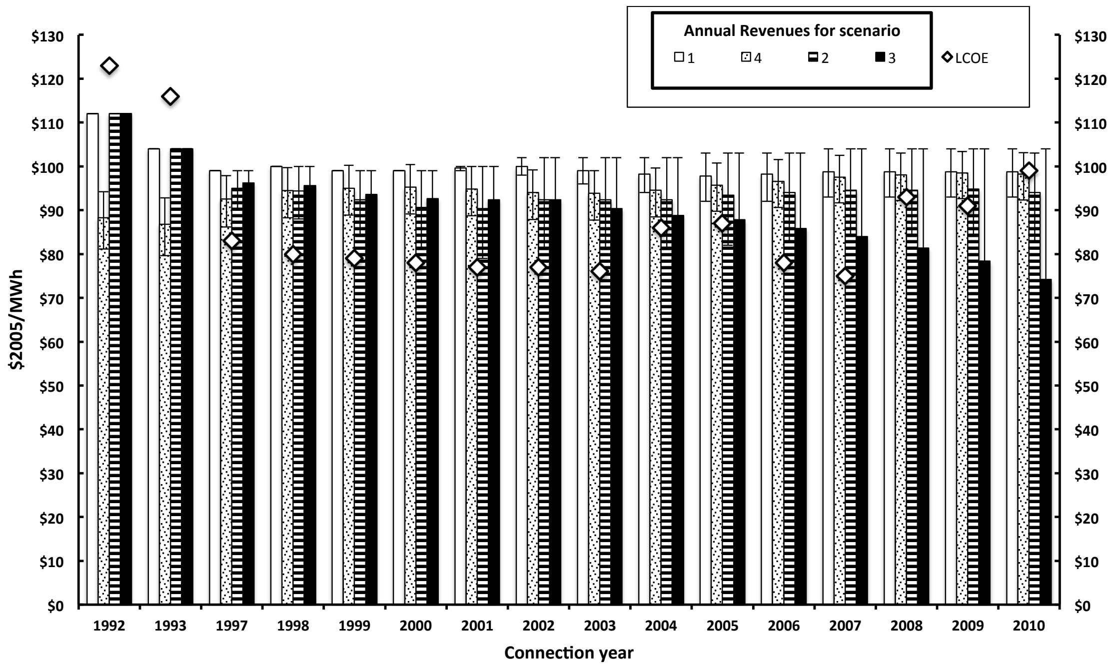

Figure 17 Annualized revenue and annualized costs (LCOE) ($2005/MWh), for Scenarios 1 through 4.
The ranges for each bar are not error bars, they instead correspond to different assumptions of spot market prices, ranging from $0/MWh to $105/MWh. 1 = scenario considers a case where Portugal would have decided to keep their 2005 law (all parks would have 15 years worth of incentives, starting counting in 2005, no matter for how long they had already been receiving incentives; 2 = same as scenario 1, but assuming the government had decided to shorten the time of FIT incentive from 15 years to 12 years; 3 = assume the FIT system would end at the beginning of 2014 for all wind parks, regardless year of connection; 4 = a fixed FIT of $105/MWh is offered to all wind parks for 15 years.

Are the existing wind parks being oversubsidized? Under all scenarios, all parks connected from 1997 to 2007 have net revenues and positive rates of return to investment (ROI), and thus have likely been oversubsidized. Note that our assumption have been fairly conservative concerning discount rates, so the parks may have been even more oversubsidized than what our results show.

Could all parks be competitive without a feed-in tariff? For wind parks built recently, i.e., from 2008 onwards, removing entirely the feed-in-tariff (Scenario 3) and requesting these parks to receive the spot market would not be economically viable. However, for all wind parks but the 1992/1993 ones, moving towards a schedule where feed-in tariffs are provided at current level only for 12 years (Scenario 2) would be enough for IPPs to recover their costs. Parks connected in 2010 are the only ones that would require spot electricity prices to be on the high end in order to be economically viable.

Should Portugal have kept the 2005 legislation unchanged? As noted previously, the 2005 legislation provides FITs for 15 years or until the park generates 33GWh/MW installed (Scenario 1). All wind parks under 2005 legislation are competitive under this scheme, except the ones connected in 2010. For parks connected in 2010, spot electricity prices have to be higher than $60/MWh for them to be economically viable once the 15-year of FIT ends.

Under the alternative policies assumed, what is the minimum price once parks have to compete in the Portuguese electricity market (OMIP) to be profitable?

In all scenarios, if we assume that spot prices are equal to, or below average current OMIP spot prices, all wind parks built prior or on 2007 are competitive in the market. If 2005's legislation had been maintained (Scenario 1), we find that all parks would be able to be economically competitive even at very low OMIP spot prices –because investment would have been recouped by the time they stop receiving FITs[16].

Could Portugal have established a simple fixed FIT equal to $105/MWh for 15 years for all projects? Yes. If wind parks would have received a FIT only for 15 years and equal to $105/MWh, they would have recovered their lifetime costs and be competitive by year 16th of production.

What could have been an optimal level of FIT? In addition to our analysis considering the first four scenarios, we estimate the NPV for different values of a hypothetical FIT paid over the 20-year lifetime of wind parks, by year of connection. Our motivation to do this analysis comes from the recent changes in the FIT legislation, in which the FIT period was increased to 20 years in Portugal –equal to the lifetime we assume for the parks. Thus, before considering the specifics of the new legislation, it is relevant to estimate the minimum fixed FIT that wind parks could receive over all their production years to cover all costs. Figure 18 shows the decision investment space of wind power investors. It depicts NPVs ($/MWh) under different assumptions on investment costs and life-long FIT, tabulated in black for investments with negative NPVs and in white with positive NPVs. For instance, 2010 projects need a lifetime-long FIT of approximately $100/MWh in order to cover its costs. New projects (assuming 2011 investment costs) need a much lower FIT, below $80/MWh to be economically profitable.

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[16] Exception being 2010 parks.

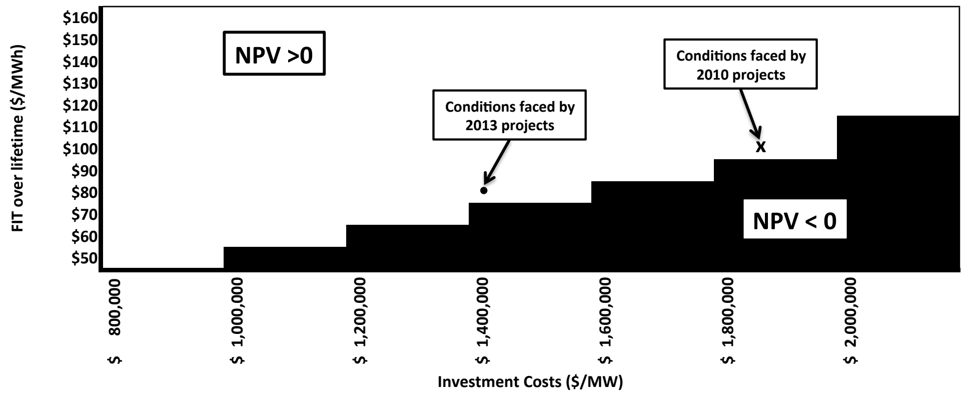

Figure 18. NPV ($/MWh) of wind parks for different investment costs and fixed FITs paid over 20 years. Basic assumption of discount rate 10%, 20 years lifetime and O&M costs of $5/MWh are used.

How much will the Portuguese government spend in wind subsidies, and what could be the alternatives? If we sum up investment and operating cost for all wind capacity connected between 1992-2010 this amounts to $4.54 billion (in $2005). Under the 2005 legislation (Scenario 1) the Portuguese government would have spent around $4.8 billion. Thus, wind is oversubsidized. The 2013 legislation offered an even worse outcome of public spending: an additional spending of $840 million, representing more than $200,000 extra spending per MW installed. All municipalities will receive between $120 million and $135 million in total over all wind parks lifetime. However, we are not accounting for environmental externalities avoided by increasing wind, savings and security gains achieved by substituting primary energy imports through the use of wind resources, and job creation, all of which will attenuate differences between government spending and the costs faced by investors (see CO_2 cost-effectiveness section for more details on this). As benefits arise, also other costs do appear as well, mainly concerned the underutilization of already existing traditional power plants, the effects on the spot electricity market price and the level of residential electricity rates due to the support of renewable sources. These benefits and costs are not included in our analysis.

Consequences of the changes to Portuguese FIT, starting February 2013. Decree-law 35/2013 establishes generous and unnecessary conditions to existent wind IPPs in exchange of immediate payments to the SEN that guarantee liquidity to cover the deficit. This approach guarantees that SEN receives payments for the next eight years, but at an overall higher cost to the country – this cost is just transferred to the future. All wind IPPs that can incur the additional investments needed to extend the lifetimes, will benefit from accepting this agreement. This is particularly true because all wind capacity installed will have already recovered initial total investment costs by the time the extension period starts, and will still receive a high tariff over $80/MWh. In the Supplementary Information we show NPV under the new conditions presented in DL35/2013. All wind parks are considered to incur extra investment costs in December 2019 to continue to operate, as their lifetimes are extended (see Introduction for details). These costs are assumed to be 35% of 2010 reported total investment costs (IEA 2010a), representing the replacement of gearbox, transformer and generator (EWEA 2009b). Further assumptions we make include: payment of extra investment costs over five year period, a 10% discount rate, and fixed O&M costs of $5/MWh. Compared to the BAU scenario, wind parks will have NPVs that are larger by at least 6%, but can be as large as three fold.

3.5.2 Sensitivity analysis

We perform a sensitivity analysis on the Business as Usual Scenario, BAU (i.e. Scenario 1). We find out that results are sensitive to the discount rate and the initial investment costs. Positive NPVs are achieved for a wide interval for all variables. The average NPV is approximately $5/MWh, and varies between -$10/MWh and $26/MWh for discount rates of 15% and 5% respectively, and between -$8/MWh and $15/MWh for a 10% change in investment costs. A low discount rate of 5% has almost the double of the impact in increasing the NPV than a 10% reduction in investment costs. This shows that appropriate financial mechanisms that maintain discount rates low are more important than promoting incentives to reduce investment costs. It also highlights that high O&M costs play an important role in the profitability level of the projects, and current and reliable data on these costs is increasingly important to properly implement a reduction in FIT levels. We are confident that our basic O&M assumption of $5/MWh is reasonable because it leads to zero NPVs for 2010 projects, which in fact made the decision investment.

Increasing the capacity factor by 10%, making O&M costs negligible or assuming an average clearing market price of $90/MWh, all have similar impacts –resulting in a two fold increase in NPVs. The fact that the clearing market price has low impact on the NPVs corroborates the feasibility of reducing or eliminating FITs and leaving wind power plants to receive the clearing market price. Lastly, since average Portuguese capacity factors are low, a reduction of only 10% in capacity factors can lead to negative NPVs.

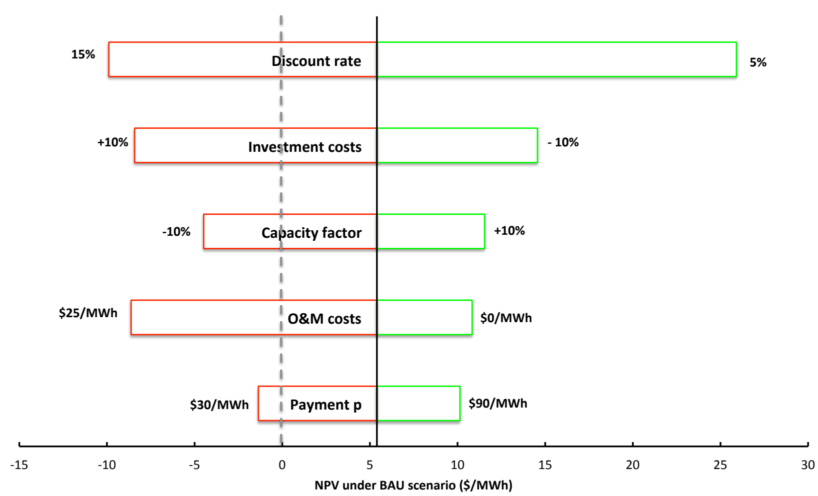

Figure 19. Tornado diagram of Scenario 1, corresponding to NPV ($/MWh) of wind parks.
Base case assumptions: 10% discount rate, average national investment costs and capacity factor, $5/MWh O&M costs, *p*=$60/MWh and 20-year lifetime.

3.5.3 CO_2 cost-effectiveness and further issues

We estimate the cost of avoided CO_2 by wind electricity generation. To estimate the amount of avoided CO_2, we assume that wind power displaces electricity from the average generation mix – including other renewables. Imports are not accounted for, which corresponds to about 8% of total electricity consumption[17] (DGEG 2014). Cost of wind electricity generation correspond to LCOE values presented in Supplementary Information.

Figure 20 shows the cost-effectiveness of wind power in terms of annualized cost per ton (investment and O&M) of avoided CO_2 emissions. Results are presented by connection year and vary between \$140/ton CO_2 and \$510/ton CO_2. This is assuming wind is displacing the average electricity mix. The cost of avoided CO_2 increases as investment costs increase or the amount of avoided CO_2 decreases. Thus, at higher wind penetration rates less CO_2 emissions are displaced. For instance, 2010 projects are the least cost-effective as those projects incurred the largest investment costs, and displaced less emissions than projects connected earlier on -when oil and coal generation was more intense. Our lower and upper limits still refer to the average electricity mix in that year, but we changed the minimum and maximum emission intensities for different energy sources as assumed by IEA[18]. We assume that wind projects displace annually the same amount of emissions as the year they connected. This is a fair assumption because electricity demand is expected to increase only 1.4% up to 2030, when the last wind park considered in this analysis will end lifetime. This assumption may result in an overestimation of CO_2 emissions avoided for late years, specially after 2025 when all coal electricity production will be replaced

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[17] Electricity imports have averaged 8% between 2000-2010, with a maximum of 17% in 2008 (a dry year).

[18] For CO_2 intensity values range between 715 and 920 g/kWh, 370 and 500 g/kWh, and 610 and 620 g/kWh for coal, gas and oil-based power plants respectively (IEA, 2011). The estimated range of CO2 intensity of the Portuguese electricity sector includes the values reported by the Portuguese Institute of Statistics (INE, 2012).

by gas power plants, and the total thermal based electricity production will decrease to 32% - compared with 46% by December 2011 (DGEG & REN 2013). Thus, costs of avoided emissions for projects that will be operating after 2025 (those connected in 2006-2010) are expected to be higher than our estimates.

Just for sake of comparison, if we were to assume that wind was always displacing coal, the cost-effectiveness would range from \$80/ton CO_2 to \$330/ton CO_2.

Since Portugal has historically been a country with a high share of renewables, accounting for a share between 15% and almost 50%, the cost-effectiveness estimates are high –on average approximately \$220/ton CO_2.

Portugal case proves how important technology performance and the selection of wind locations are determinant in the cost-effective estimates. For example, even though investment costs for years 1993 and 2010 are very similar, and in 2010 there was a larger share of renewables in electricity production (48% in 2010 vs 30% in 1993), the cost estimates for 2010 are significantly lower than those of 1993 projects. This is because capacity factor improved significantly from 1993 to 2010, from 9% to 26%.

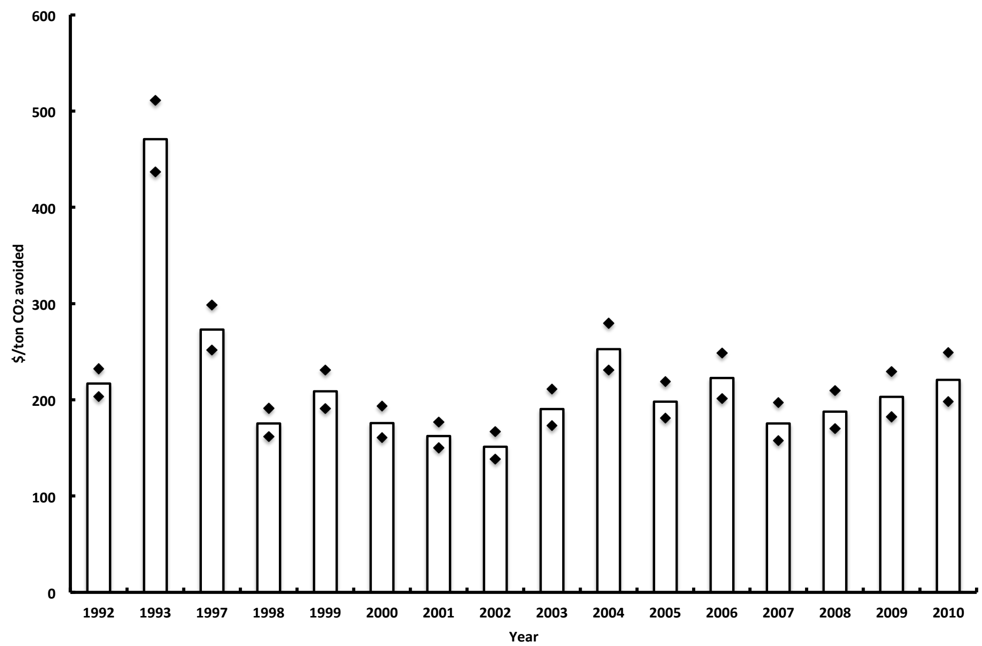


Figure 20. Cost-effectiveness in $/ton of CO_2 avoided by wind power in Portugal, by connection year. Assumptions for cost estimates: 20-year lifetime, 10% discount rate, O&M $5/MWh.
Assumptions for CO_2 emissions estimates: CO_2 intensity in Portugal of coal-based power plants 818 g/kWh, of gas-based power plants 435 g/kWh and of oil-based power plants 615 g/kWh. Further assumptions: wind power displaces electricity from the annual average electricity mix and annual capacity factor of each wind project equals national average annual capacity factor up to 2011 and afterwards equals 0.23. The dots correspond to low and high bounds for CO_2 intensity when computing the intensity of the Portuguese electricity mix: 715 and 920 g/kWh, 370 and 500 g/kWh, and 610 and 620 g/kWh for coal, gas and oil-based power plants respectively (IEA 2011).

Wind is generally also suggested as a strategy to promote energy independence. Electricity accounts for approximately 30% to 40% of all primary energy consumption, and wind power accounted for 17% of this by December 2010. Thus, wind power accounted for about 6% of total primary energy consumption the year with the largest wind penetration. Although wind power is part of the energy independence path, other measures such as efficiency and transportation policies also need to be pursued if energy independence is to be achieved.

Thus, increasing wind power may, to some extent, result in a reduction in fuel imports, even in the case that fossil fuel prices decreases. A decrease in fossil fuel prices would result, in the short term, in lowering marginal generation costs of fossil fuel generation, i.e. lowering spot electricity prices. However, from a national energy security perspective and to meet environmental goals, one could still foresee wind power playing a role.

There were multiple goals that Portugal aimed to achieve by promoting the growth of the wind sector in the country. Those included job creation, technology transfer and innovation, the creation of an industrial cluster (see *Additional details on wind policies in Portugal*, in the Supplemental Information). The benefits and the costs associated with these strategies are not incorporated in our analysis, as our goal was to quantify strictly the economic profits arising from the payment of wind feed-in tariffs, and that this is independent of other costs and benefits that the promotion of wind power has brought to Portugal.

3.6 Conclusions and policy recommendations

Decree-Law 33A-2005 guarantees a FIT paid to wind IPPs until December 2019 for parks that connected to the electricity grid on 1992-2005, and until 2021-2024 for parks that connected between 2006-2010, respectively. After that, it dictates that wind parks will receive a price for production equal to the average annual spot market price plus green certificates if available. We find that under the 2005 legislation, all projects connected in 1997 and onwards will have a positive NPV if they enter the competitive electricity market, and the total spending in FITs is larger than needed. This means that wind power has been oversubsidized and that starting 2020, wind parks could instead be players in the spot market.

Portugal could have cut spending in the form of FITs by decreasing the FIT period from 15 to 12 years (Scenario 2) -and wind parks would still be economically profitable. Only more recent projects (2008-2010) would need to receive in average a market price larger than

$30/MWh to have positive NPVs. The fact that under the hypothetical scenario of Portugal ending the FIT payments by December 2013 still leads to positive NPVs for all projects connected up to December 2007 (assuming they receive in average a market price of at least $30/MWh starting January 2014) is an indicator of the over subsidization of the wind FIT scheme and a need to assess alternatives and move forward with policy innovation.

However, Portugal published a recent reform arguing the need to cut SEN deficit. Instead of cutting FITs (which are increasing the deficit), the government increased them in exchange of immediate payments from the wind producers to the electricity system. In reality, these reforms are transferring the deficit into the future, resulting in a more expensive and unsustainable approach. In fact, wind parks will have larger profits under the new legislation resulting in an increase of the NPVs at least by 6%.

Wind development in the country has been remarkable, and Portugal has achieved a reduction in 22 million metric tons of CO_2 emissions, and a reduction of its fossil fuel based electricity generation from 80% to roughly 50%, mainly because of wind. Nonetheless, it is extremely urgent to put into perspective the design of the policy mechanisms that are currently providing large benefits to wind producers and financed by all Portuguese consumers.

3.7 Supplemental Information

3.7.1 Additional details on wind policies in Portugal

Wind energy policies were promoted in Portugal on different grounds and to meet a diverse set of goals. For example, in the public tender of 2005 Portuguese Government required the awardee to allocated funding to R&D, to provide investment and employment in some of the country's less favored regions, to encourage the transfer of technology to Portugal from abroad, and to create a new source of export of goods, limiting the import of wind turbines (Portugal 2010; ERSE 2010; Diário da República 2005; Eneop 2009b). ENEOP - Eolicas de Portugal SA won the first and the largest phase of this bid, obtaining the rights for 1200 MW[19]. The 2005 tender was granted to ENEOP under the condition of ENEOP to build an industrial cluster in Viana do Castelo, Portugal. The cluster includes five companies and four specialized centers that in conjunction with other national and foreign companies can provide all services to the installation and maintenance of wind parks. In total, ENEOP has invested 200 million euros in the cluster, has installed 970 MW of wind power up to June 2013, and reports the creation of 2,000 direct jobs in the industrial center and that the industrial cluster represents 2.5% of the GDP of the region Minho-Lima (Eneop 2009b). Wind parts produced in Portugal include rotor blades, synchronous generators, nacelles and electrical modules, and pre-built concrete towers, which are all prepared to be incorporated in Enercon wind turbines (Eneop 2009c). ENEOP reports that the industrial cluster was created, and that is currently exporting more than 60% of the production. (Eneop 2009a).

[19] The remainder was attributed to the Ventinvest consortium. Afterwards there was a new tender which awarded another 190 MW to different small promoters.

In addition to the feed-in tariffs granted to wind power, Portaria 1463/2007 specifies the incentives to support small and medium companies (PME for its Portuguese name). PMEs can be granted tax reductions, reduction on interest rates and investment subsidies if they invest in projects of diversification of energy sources, which includes the use of wind generators.

Table 8. NPV and equivalent annual revenue (AR) of Portuguese Wind Parks connected between 1992-2010 ($2005/MWh), by connection year for Scenarios 1-4.

Each scenario considers the following payments once the FIT is over: $0/MWh, $30/MWh, $60/MWh, $90/MWh, $105/MWh. Capacity factors are averages over the park lifetime.

	NPV Sc.1 $/MWh (0,30,60,90, 105)	NPV Sc.2 $/MWh (0,30,60,90, 105)	NPV Sc.3 $/MWh (0,30,60,90, 105)	NPV Sc.4 $/MWh (0,30,60,90, 105)	LCOE ($2005/MWh) Capacity factor	AR Sc.1 $/MWh (0,30,60,90,105)	AR Sc.2, 12 years $/MWh (0,30,60,90,105)	AR Sc.3, 2013 $/MWh (0,30,60,90,105)	AR Sc. 4 $/MWh (0,30,60,90,105)
1992	-3	-3	-3	-15, -13, -11, -9, -8	**$117 0.20**	110	110	110	79, 84, 89, 94, 96
1993	-4	-4	-4	-14, -12, -10, -8, -7	**$113 0.20**	103	103	103	80, 84, 88, 93, 95
1997	7	4, 5, 6, 7, 7	4, 5, 6, 7, 7	2, 3, 4, 6, 7	**$83 0.21**	99	99	93, 95, 96. 98, 99	86, 90, 93, 96, 98
1998	8.5	5, 6, 7, 8, 9	4, 5, 6, 8, 9	3, 5, 6, 8, 8	**$80 0.22**	100	91, 93, 96, 98, 100	91, 93, 96, 98, 100	88, 92, 95, 98, 100
1999	9	4, 5, 7, 8, 9	4, 5, 7, 8, 9	4, 6, 7, 9, 9	**$79 0.22**	99	87, 91, 94, 97, 99	87, 91, 94, 97, 99	89, 92, 95, 99, 100
2000	9	3, 5, 7, 8, 9	3, 5, 7, 8, 9	5, 6, 8, 9, 10	**$78 0.22**	99	85, 89, 93, 97, 99	85, 89, 93, 97, 99	89, 92, 96, 99, 100
2001	9, 9, 10, 10, 10	3, 5, 7, 9, 10	3, 5, 7, 9, 10	5, 6, 8, 9, 10	**$77 0.22**	99, 99, 100, 100, 100	83, 88, 93, 98, 100	83, 88, 93, 98, 100	89, 92, 95, 98, 100
2002	9, 10, 10, 11, 11	2, 4, 7, 10, 11	2, 4, 7, 10, 11	5, 6, 8, 9, 10	**$77 0.22**	98, 99, 100, 101, 102	81, 87, 93, 99, 102	81, 87, 93, 99, 102	88, 91, 94, 98, 99
2003	9, 9, 10, 11, 11	2, 5, 7, 10, 11	0, 4, 7, 10, 11	5, 7, 8, 9, 10	**$76 0.22**	96, 97, 99, 101, 102	81, 87, 93, 99, 102	77, 84, 91, 98, 102	88, 91, 94, 97, 99
2004	3, 4, 5, 6, 7	-2, 0, 3, 5, 7	-6, -2, 1, 5, 7	1, 2, 4, 5, 6	**$86 0.23**	94, 96, 98, 101, 102	81, 87, 93, 99, 102	73, 81, 90, 98, 102	88, 92, 95, 98, 100
2005	2, 3, 5, 6, 7	-2, 0, 3, 5, 7	-8, -3, 1, 5, 7	1, 2, 4, 5, 6	**$87 0.23**	92, 95, 98, 101, 103	82, 88, 94, 100, 103	70, 79, 89, 98, 103	90, 93, 96, 99, 101
2006	6, 8, 9, 10, 11	2, 5, 7, 10, 11	-5, -1, 4, 9, 11	6, 7, 8, 10, 10	**$78 0.23**	92, 96, 98, 102, 103	83, 89, 95, 100, 103	65, 76, 87, 98, 103	91, 94, 97, 100, 102
2007	8, 9, 10, 12, 12	4, 6, 9, 11, 12	-6, -1, 4, 10, 12	7, 8, 10, 11, 12	**$75 0.23**	93, 96, 99, 102, 104	84, 89, 95, 101, 104	60, 73, 85, 98, 104	92, 95, 98, 101, 103

2008	0, 1, 2, 4, 4	-4, -2, 1, 3, 4	-17, -11, -5, 1, 5	-1, 1, 2, 3, 4	**$93 0.23**	93, 96, 99, 102, 104	84, 89, 95, 101, 104	54, 69, 83, 97, 104	92, 95, 98, 101, 103
2009	1, 2, 4, 5, 5	-3, -1, 2, 4, 6	-18, -12, -5, 2, 6	1, 2, 3, 5, 5	**$91 0.23**	93, 96, 99, 102, 104	84, 90, 95, 101, 104	48, 64, 80, 96, 104	93, 96, 99, 102, 103
2010	-3, -1, 0, 1, 2	-7, -4, -2, 1, 2	-25, -17, -10, -2, 2	-3, -1, 0, 1, 2	**$99 0.23**	93, 96, 99, 102, 104	83, 89, 95, 100, 103	39, 58, 76, 94, 104	92, 95, 99, 102, 103

3.7.2 NPV analysis at national level

The first four columns in Table 8 summarize the NPV results for all scenarios, and for wind parks connected in Portugal between 1992-2010. Different columns assume different spot electricity prices that hold once the FIT period ends. The last five columns of Table S1 show LCOEs and average capacity factors over lifetime, and annualized revenues *(AR)*. As expected, projects for which *AR*<LCOE have negative NPV and are highlighted in red.

NPVs vary between -$25/MWh and $12/MWh, depending on the scenario considered. The lowest NPV is attained for wind parks that connected in 2010 and stop receiving the FIT by December 2013, and the highest occur for 2007 projects, which incurred one of the lowest investment costs and had one of the highest average capacity factors. Under Scenario 1, NPVs vary between -$4/MWh and $12/MWh. If the FIT ends after 12 years of production (Scenario 2), NPV decreases to -$7/MWh and if FIT ends in December 2013 it goes down to -$25/MWh. Lastly, if wind parks would have received a fixed FIT of $105/MWh for 15 years (Scenario 4), only the least and most recent projects would have negative NPVs for some of the cases.

For illustration purposes, estimates on the return of investment (ROI) are also shown in Table 10.

NPV of projects under 2013 new legislation

Table 9 shows the NPV estimates for existing wind parks connected between 1992-2010, under the two options specified in the new legislation of 2013. The first option consists of lower payments to SEN and a five year FIT extension, and the second consists of higher payments and a seven year extension period. The last column shows the option that wind parks are likely to choose, i.e., the option that results in the larger average expected NPV. Except for wind parks connected in 2007, every park is better off by accepting a seven year FIT extension. Parks connected in 2007 are almost indifferent between both options. But more relevantly, all wind parks will have larger profits under 2013 legislation than under 2005 legislation – regardless the option chosen. This highlights that even though the new ruling will bring immediate liquidity to cover part of the SEN deficit, it will increase total spending in the long run and will provide support to wind parks that have already covered all their investment costs.

Table 9. NPV ($2005/MWh) under the new legislation of February 2013

	Type of project according to 2013 legislation	**NPV ($2005/MWh) Option 1 (5 years of extension, payment of $6,700/MW to SEN)**	**NPV ($2005/MWh) Option 2 (7 years of extension, payment of $7,500/MW to SEN)**	**Option selected**
1992	Old	-$1 to $2	-$1 to $2	Option 2
1993	Old	-$1 to $1	-$1 to $2	Option 2
1997	Old	$6 to $9	$7 to $10	Option 2
1998	Old	$7 to $10	$7 to $11	Option 2
1999	Old	$7 to $10	$7 to $11	Option 2
2000	Old	$7 to $10	$8 to $11	Option 2
2001	Old	$8 to $11	$8 to $12	Option 2
2002	Old	$8 to $11	$8 to $12	Option 2
2003	Old	$8 to $12	$8 to $13	Option 2
2004	Old	$3 to $7	$3 to $9	Option 2
2005	Old	$2 to $7	$3 to $9	Option 2
2006	New	$7 to $12	$7 to $13	Option 2
2007	New	$8 to $13	$7 to $13	Option 1
2008	New	$1 to $6	$1 to $6	Option 2
2009	New	$1 to $7	$2 to $7	Option 2
2010	New	-$2 to $4	-$1 to $4	Option 2

Assumptions: 2.5% payment to the Municipality (Município in Portuguese), $5/MWh O&M costs, 10% discount rate, 35% of 2010 investment costs incur in 2019 for all parks to extend their lifetimes for additional period. Old and new projects refer to those connected before and after DL33A/2005, respectively. Lower and upper bound refer to the FIT limits established in DL35/2013.

Table 10. Return of Investment (ROI) and equivalent annual revenue (AR) of Portuguese Wind Parks connected between 1992-2010 ($2005/MWh), by connection year for Scenarios 1-4.

Each scenario considers the following payments once the FIT is over: $0/MWh, $30/MWh, $60/MWh, $90/MWh, $105/MWh. Capacity factors are averages over the park lifetime.

	ROI Sc.1 % (0,30,60,90, 105)	ROI Sc.2 % (0,30,60,90, 105)	ROI Sc.3 % (0,30,60,90, 105)	ROI Sc.4 % (0,30,60,90, 105)	LCOE ($2005/MWh) Capacity factor	AR Sc.1 $/MWh (0,30,60,90,105)	AR Sc.2, 12 years $/MWh (0,30,60,90,105)	AR Sc.3, 2013 $/MWh (0,30,60,90,105)	AR Sc. 4 $/MWh (0,30,60,90,105)
1992	-9	-9	-9	-35, -31, -29, -25, -24	**$117 0.20**	110	110	110	79, 84, 89, 94, 96
1993	-10	-10	-10	-32, -29, -25, -25, -20	**$113 0.20**	103	103	103	80, 84, 88, 93, 95
1997	22	13, 16, 18, 20, 22	13, 16, 18, 20, 22	5, 9, 14, 18, 20	**$83 0.21**	99	99	93, 95, 96. 98, 99	86, 90, 93, 96, 98
1998	27	15, 18, 22, 25, 27	15, 18, 22, 25, 27	11, 16, 20, 25, 27	**$80 0.22**	100	91, 93, 96, 98, 100	91, 93, 96, 98, 100	88, 92, 95, 98, 100
1999	28	12, 17, 21, 25, 28	12, 17, 21, 25, 28	14, 18, 23, 27, 30	**$79 0.22**	99	87, 91, 94, 97, 99	87, 91, 94, 97, 99	89, 92, 95, 99, 100
2000	30	10, 15, 21, 27, 29	10, 16, 21, 27, 30	16, 20, 25, 29, 32	**$78 0.22**	99	85, 89, 93, 97, 99	85, 89, 93, 97, 99	89, 92, 96, 99, 100
2001	30, 31, 32, 32, 33	8, 15, 22, 29, 33	8, 15, 22, 29, 33	16, 21, 25, 30, 32	**$77 0.22**	99, 99, 100, 100, 100	83, 88, 93, 98, 100	83, 88, 93, 98, 100	89, 92, 95, 98, 100
2002	30, 32, 33, 35, 35	6, 14, 23, 31, 35	6, 15, 23, 31, 36	16, 20, 25, 30, 32	**$77 0.22**	98, 99, 100, 101, 102	81, 87, 93, 99, 102	81, 87, 93, 99, 102	88, 91, 94, 98, 99
2003	28, 31, 33, 36, 37	7, 16, 24, 33, 37	2, 12, 22, 32, 37	17, 22, 26, 31, 33	**$76 0.22**	96, 97, 99, 101, 102	81, 87, 93, 99, 102	77, 84, 91, 98, 102	88, 91, 94, 97, 99
2004	9, 12, 15, 18, 19	-6, 1, 8, 16, 19	-16, -6, 4, 14, 20	3, 7, 10, 14, 16	**$86 0.23**	94, 96, 98, 101, 102	81, 87, 93, 99, 102	73, 81, 90, 98, 102	88, 92, 95, 98, 100
2005	6, 9, 13, 17, 19	-6, 1, 8, 15, 19	-21, -10, 2, 13, 19	3, 7, 11, 14, 16	**$87 0.23**	92, 95, 98, 101, 103	82, 88, 94, 100, 103	70, 79, 89, 98, 103	90, 93, 96, 99, 101
2006	20, 25, 29, 33, 35	7, 15, 23, 31, 35	-17, -2, 13, 17, 36	18, 22, 26, 31, 36	**$78 0.23**	92, 96, 98, 102, 103	83, 89, 95, 100, 103	65, 76, 87, 98, 103	91, 94, 97, 100, 102
2007	25, 30, 34, 39, 41	12, 20, 29, 37, 41	-21, -3, 14, 32, 41	23, 28, 32, 37, 39	**$75 0.23**	93, 96, 99, 102, 104	84, 89, 95, 101, 104	60, 73, 85, 98, 104	92, 95, 98, 101, 103
2008	0, 3, 7, 10, 12	-11, -5, 2, 9, 12	-44, -28, -12, 4, 12	-1, 2, 6, 9, 11	**$93 0.23**	93, 96, 99, 102, 104	84, 89, 95, 101, 104	54, 69, 83, 97, 104	92, 95, 98, 101, 103
2009	2, 6, 10, 13, 15	-9, -2, 5, 12, 15	-50, -32, -13, 6, 15	2, 6, 9, 13, 14	**$91 0.23**	93, 96, 99, 102, 104	84, 90, 95, 101, 104	48, 64, 80, 96, 104	93, 96, 99, 102, 103
2010	-7, -3, 0, 3, 5	-17, -11, 4, 2, 5	-63, -44, -24, -5, 5	-7, -4, 0, 3, 5	**$99 0.23**	93, 96, 99, 102, 104	83, 89, 95, 100, 103	39, 58, 76, 94, 104	92, 95, 99, 102, 103

4 Chapter 4: Wind Power Curtailment in the Distribution Grid of Portugal under the 2030 objectives

4.1 Abstract

The 2020 renewable energy goals in Portugal include 6 GW of cumulative wind capacity, which necessitates the connection of 2 GW in the next years. We assess the effects associated with increasing wind power in two regions of the distribution grid (60 kV). The regions of analysis are chosen based on a power flow analysis that highlights critical lines. For these regions, we estimate the frequency distribution of wind spill and quantify the annual wind power curtailment under different wind capacity additions and grid reinforcements, using 2012 data with 15-minute resolution, and considering local grid investment costs. We use a static model of the line, and include capacity restrictions of both the transformer and other elements of the substations. We compare the costs of spilling wind electricity with the costs of upgrading one line of the distribution grid. Our results show that if no further grid investments are made and wind capacity increases up to 100 MW in the region analyzed, total annual electricity spill is approximately 20%. In fact, we find that wind power curtailments as large as 20% still result in profitable investments and returns to investment of at least 14%. We recommend that Portuguese policy makers update the wind energy policy by eliminating the guarantee of no wind power curtailment. Such risk should instead be born by the wind power producers when making investment decision on which site to build and operate. This way, already 'occupied' connection points will become available to new entrants, lowering the total investment costs of new wind investors.

4.2 Introduction

Existing studies highlight the importance of carefully calculating the level and duration of feed-in tariffs (FITs) in order to efficiently foster renewable energy generation (Mendonça 2007; Mendonça et al. 2009; Couture & Gagnon 2010; del Río & Gual 2007; del Río 2012; Rowlands 2005). But less attention is paid to the details and conditions of grid licenses, and the way these licenses are designed. The penetration of renewable energy sources depends on grid access policies, not just the FIT.

In Portugal, the FIT design consists of a fixed and high tariff paid to wind independent power producers (IPPs) over 20 years (Diário da República 2013). In terms of grid access, the Regulator (ERSE) established two procedures to give grid licenses and install wind projects. ERSE decides which of the projects receive a connection license, depending on a set of criteria ranging from technical to geographical conditions. Once a project is selected, the wind power producers receive grid licenses that guarantee access to the grid to all wind power generation at any time. This means that all wind power generated feeds the grid, and each unit of energy generated is paid a high tariff - the average FIT from 2000 to 2010, was about two times the clearing market price since the Iberian Electricity Market (MIBEL) was established. Combined, the level of the incentive and guaranteed grid access create a very expensive mechanism for wind diffusion.

In Chapter 3, we estimated costs associated with the design of the FIT level (Peña et al. 2014). We estimated the profits of wind power producers in Portugal and concluded that the total amount of payments have overcompensated most of the existing wind parks. In fact, under 2005 legislation (Diário da República 2005), all wind parks connected up to December 2010 will be economically profitable after the FIT period ends and, under the 2013 legislation (Diário da

República 2013), parks will end up receiving even greater economic incentive[20] than under the 2005 legislation. In this work, we explore the costs and implications of guaranteeing 100% access to the grid for new wind parks in two regions of the country in the 60 kV grid. We do this from the perspective of the wind investor, and do not consider the optimal integration of wind power at the national level.

Supply-management mechanisms can help integrate large shares of intermittent sources (Grant et al. 2009). Currently, Portugal does require the provision of ancillary services as part of supply management strategies. The allowance for the connection of more wind power to already occupied grid lines can be classified as another supply management mechanism, in the system planning domain, that contributes to a more efficient use of the network infrastructure. Analysis assessing the network occupancy that account for wind power uncertainty, along with other supply management mechanisms, can contribute to the implementation of cost-effective wind power integration policies.

We estimate the expected congestion of the 60 kV grid if more wind capacity is added to one substation of the utility Electricidade de Portugal (EDP), and the resultant reduction in the capacity factor of existing wind parks. Also, we assess the costs of upgrading the grid in one region, both under a 100% wind reception scenario and when this guarantee is released. Lastly, we compare the costs of upgrading the grid with the wind electricity losses if no upgrade takes place, providing policy recommendations that eliminate the guaranteed grid access requirement.

[20] The motivation to change the 2005 legislation into the 2013 legislation was the urgency to cover the tariff deficit in the electricity sector. The deficit in fact has increased due to different and many subsidies, including the support to RE power plants.

An overview of the impacts of the addition of more renewable capacity to the national power demand profile is included in the Supplemental Information.

4.3 Wind integration in the 60 kV grid

Of the 4,200 MW of wind power currently installed, 60% are connected to the distribution grid (60 kV lines), and 40% to transmission lines (220kV and 440kV). The distribution line is owned and operated by EDP Distribution, while the transmission line is owned and operated by REN. Portugal has continuously reduced the number of annual interruptions in the system to very small values, and has kept installing new 60 kV lines, both of which might be indications of over capacity in the distribution grid. For example, in 2012 there were no interruptions (zero times) despite the fact that several lines were out of service due to windstorms (REN, 2013). The expected new wind parks will connect both to the transmission and distribution networks. At the transmission level, the transmission system operator (TSO) is Redes Energéticas Nacionais (REN) and is interested in developing more than 250 km of 400 kV lines in Beiras, between the regions Abrantes/Nisa and Covilhã, Guarda and Torre de Moncorvo. Other transmission line projects are being explored for the regions Eixo Tábua, Pereiros and Penela (REN 2011b). Ferreira (2008) already studied the utilization of the transmission lines under extreme scenarios and found that the maximum expected utilization is less than 50% at all times. On the other side, at the distribution level, EDP and wind investors have installed 20,000 km of new distribution lines between 2005 and 2010, representing 10% of today's total network capacity. Investors in the new wind parks that will be connected between now and 2030 are exploring the option of building more 60 kV lines in order to guarantee the 100% feed-in requirement. Thus, these potential investors (who would be in charge of making the necessary line investments) and EDP are highly interested in knowing the current distribution line capacity in critical regions.

Until now, most of the wind parks connected to 60kV lines or to EDP substations have built 60kV branch-lines at their own expense, increasing investment costs, which in turn has required higher and longer FIT periods. Some of these lines were built to connect parks operating in the mountains of the Portuguese northeast to the transmission grid and the population, most of which lives along the Atlantic west coast. Some were built in parallel to existing lines in order to increase distribution capacity, and to eliminate the risk of congestion and power curtailment. Here, we estimate the utilization of one representative existing distribution line when wind power increases.

The integration of wind power in distribution and transmission networks has already been studied. Literature sources highlight technical problems with the integration of wind power in the transmission grid (Martinez de Alegría et al. 2006), and in the distribution grid (Mozina 2010). A lot has been written about the need to harmonize grid codes (EWEA 2009a; Martinez de Alegría et al. 2006). Broad attention is given to technical requirements, including interconnection protection, generator protection, grounding of the interconnection transformer and protection against induced over voltages, so that they can be met at minimum overall system cost. The European Wind Energy Association recommends that "requirements for wind power plants should be neither excessive nor discriminatory, and should not be stricter than grid codes for other generation technologies unless there is a specific technical justification." (EWEA 2009a). This work does not look at the specific technical requirements for connection of new wind power capacity in the 60 kV grid, but at wind power's 100% grid access guarantee. Since the allocation of connection permits is based on the existing capacity of the connection points, and wind power investors cannot upgrade the grid without the approval of the grid operator, our goal is to make policy recommendations that do not concede excessive grid capacity to wind power generation.

From the system modeling perspective, the resulting utilization (and voltage nodes) of the system when new wind power capacity is added can be analyzed using deterministic power flow models or probabilistic power flow models (Shujun et al. 2010). Deterministic power flow models are the most common methodology used by utilities to determine the occupancy of lines at critical moments or under representative scenarios. Using this approach, Ferreira (2008) already showed that the highest utilization of the Portuguese transmission grid is less than 50% and the current maximum utilization factors of the transmission system are substantially lower than 50%.

Probabilistic power flow models were introduced in 1974, and the most common simulation approaches use Monte Carlo techniques and analytical methods using cumulants and expansions of Gaussian density functions to model grid utilization.

Shujun et al. (2010) propose an alternative expansion that converges for non-Gaussian probability density functions, which is a better approximation when wind power (or other types of intermittent power) injections increase. We do not define analytically a probability density function of the power flow in the 60 kV line analyzed, but rather, we use a representative statistical approach to define the resulting occupancy in the line -which in fact is poorly fitted by a Gaussian probability density distribution.

Others have estimated renewable power curtailment, under the objective of minimizing total marginal power generation cost in the Portuguese transmission network (Redondo Faias 2011). We do not incorporate system cost considerations in our analysis as others have done –such as reducing losses by reconfiguration of the network (Lueken et al. 2012) but rather only local costs that impact the investment decision. Nevertheless, our results have policy implications that impact total system cost, because available distribution and transmission capacity decreases for the whole system as more wind power is added.

There are studies covering the optimal grid capacity to connect wind power, and estimated the reliability of the grid when wind power is added. Regarding the optimization of line capacities, Pattanariyankool and Lave studied the optimal transmission factor of four wind farms in the northeastern United States (Pattanariyankool & Lave 2010). They defined transmission factor as the ratio between capacity of the line and capacity of the wind farm, i.e. a transmission factor of 1 represents the case of a line with a capacity equal to the capacity of the wind farm connected to the line. Their objective function consists on the maximization of total NPV of the projects, considering a 40 year-lifetime of the park (with 20-year lifetime of the turbines), a power purchase agreement with the utility with a fixed tariff and economies of scale on transmission costs. They concluded that for wind farms with capacity factors between 30-35%, and lines of 500 miles length, the optimal transmission factor is between 80-86%. Longer lines lead to optimal transmission factors ranging between 70-76%, and the optimal transmission factor decreases as capacity factors of the wind parks decrease. The capacity factor of the wind farms studied is higher than the capacity factor of the Portuguese study analyzed, and the transmission costs are approximately 30% larger. Nevertheless, their results apply directly to this study since the objective function considers the investors' perspective of profit maximization, the transmission costs are covered by the investor, there is a fixed power purchase agreement for all power delivered, power losses are considered negligible and power factor is 1. Since in the U.S. it is not mandatory to feed-in all wind power in the transmission line, their objective function allows for wind power curtailment, i.e. if wind power is larger than line capacity at a given point in time, the excess of power is spilled. Thus, their analysis covers directly the trade-off between having some wind power spill and transmission lines with lower capacities. Their results show that a wind park with a capacity factor of .3 and a transmission line of 500 miles, the optimal transmission factor is 80%. For the Portuguese case, this would mean that in region 1, the transmission line capacity should be approximately 4.8 MW for a wind park of 6 MW, and 80 MW for a wind park of 100 MW. Also, energy storage capacity can be a feasible alternative to transmission investments, specially when transmission distances are long to cover. In particular, Lamy et al. (2014) estimate the transmission and energy storage capacity for wind farm of 200 MW in North Dakota, U.S. "that yields the lowest average cost of generating and delivering electricity ($/MW h), […] and (they) find that transmission costs must be at least $600/MW-km and energy storage must cost at most $100/kW h in order for this application of energy storage to be economical." (Lamy et al. 2014)

Regarding the impact of different connection alternatives in the electric system's reliability, Billinton and Wangdee study the reliability of a bulk electric system when large wind developments are connected, and study alternatives to reinforce the system (Billinton & Wangdee 2007). Their analysis considers four reliability indexes: expected frequency of load curtailment (EFLC), the expected duration of load curtailment (EDLC), the expected interruption cost (ECOST), and the delivery point unavailability index (DPUI). They present a total of 11 alternatives of connection of a wind park to the bulk electric system (a modified version of the IEEE-RTS) -five considering the wind power investor pays the overall connection costs to the bulk system, and six considering the costs are shared between the investor and the grid operator. Each alternative provide different reliability indexes, but overall, if the wind investor needs to pay all the connection costs, he/she will attempt to minimize the overall costs and build the shortest transmission line to the system. If the objective is to increase overall system reliability, the result is that the wind investor will negotiate with the grid operator to share the costs, and the alternative selected is not building the shortest transmission line.

As well, Archer and Jacobson show that the interconnection of wind farms increases reliability and reserve requirements of the electric system because the wind power output will present less variability (Archer & Jacobson 2007). They studied 19 sites in the Midwestern United States, and concluded that by connecting sites with wind speeds higher than 6.9 $m \cdot s^{-1}$, standard deviations of array-average wind speed and wind power decreased. In particular, they found that a third or more of the power of the array can be used for reliable electric power and the remaining intermittent portion can be used for other services, such as powering batteries for transportation. They also found that although the marginal benefit of interconnecting one more wind site to the array decreases as more wind parks are added, no saturation of the benefits was found. Moreover, they found that the long-distant portion of transmission capacity can be reduced by 20% with only a 1.6% loss of energy when wind parks are interconnected to a single point. Their results do not depend on the load, i.e. are general.

In addition, Pattanariyankool and Lave also include in their profit maximization analysis (Pattanariyankool & Lave 2010) the alternative of interconnecting two wind parks. In this case, the costs of the transmission line between two farms offsets the benefit of a lower wind power correlation. This means that from the investor perspective adding a second wind farm does little to lower the transmission costs of delivered power. Even though in this piece of work we do not model interconnection of additional wind farms to the site, these studies highlight that such consideration might be feasible if the objective is to increase system reliability rather than maximizing the wind investor profit.

4.4 Method

We start by identifying the most critical distribution lines (60 kV) in Portugal, i.e. lines that present high occupancy rates[21] under a hypothetical scenario in which national wind cumulative capacity is increased to 130% and 200% level with respect to December 14th, 2012 (the historical wind peak). In order to do so, we use DPlan Software to run a power flow analysis in the distribution grid of 60 kV at a national level to identify the 'critical' regions.

In order to perform the power flow, DPlan models a simple version of the transmission grid, i.e. only the most critical transmission lines of 220 kV and 440 kV. These lines are included in the 60kV power flow because the networks are connected. DPlan then balances load, i.e. all generation equals demand. The interconnection grid capacity between Portugal and Spain is not modeled. For example, we see high line utilization in the Cabril region when wind power penetration at the national level is doubled. This is shown in Figure 21. Even though the transmission grid is not fully modeled, we are confident that the transmission grid capacity does not constraints our analysis (Ferreira 2008). Thus, we can rely on the utilization rates shown by DPlan to identify critical distribution lines.

[21] Color convention in Figure 21 is as follows: Red: Above 105% of nominal capacity. Orange: Between 100%-105% of nominal capacity. Yellow: Between 90%-100% of nominal capacity. Light green: Between 75%-90% of nominal capacity. Dark green: below 75% of nominal capacity. Nominal capacity for each element is a library in DPlan that EDP defines. For each element there are three values: winter, typical and summer nominal capacities. Summer refers to 80% of typical capacity and winter to 120% of typical capacity. Even though we do not know the details of how EDP establishes typical values, these are usually defined as the minimum capacity between four estimated capacities according to {temperature, current, corone effect}.

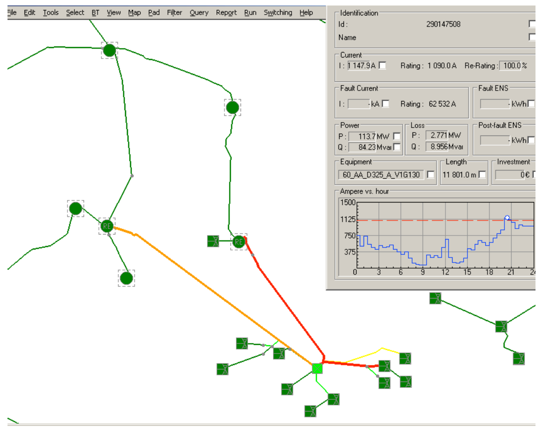


Figure 21 Screen shot of power flow result for one Portuguese region (Cabril).
Assumption: national wind power capacity doubles compared to December 14, 2012 (a historic wind peak of 3750 MW, i.e. 86% of wind power operating at full capacity).
Lines in yellow and red represent high occupancy rates (above 90% and 105% respectively). The distribution line shown is one of the very few at national level that present power curtailment, equal to approximately 6% of the line maximum capacity with a frequency of 1%.

In addition to this method of identifying critical lines, after communications with EDP Distribution, we elicited their judgment as to which other lines are potentially critical. The criteria were to look at regions that have shown more interest in incentivizing the development of new wind parks –i.e. those that have already passed connection license inquiries to EDP. We also chose regions with a mix of generation sources and with consumers at 30kV or 10kV.

After determining the case studies for the critical lines, we have determined the 'local system capacity', i.e. the nominal capacity of both the substation and the line of interest connected to the transformer. Using substation blueprints provided by EDP, we define system capacity (C_s) as:

$$C_s = \min \text{capacity}\, \{substation\ bus, transformer, line\}$$

Where C_S = local system capacity, dictated by the element that creates a capacity bottleneck.

We then consider a simple model of the system capacity. Others have raised the importance of including weather data to estimate the available capacity of distribution lines (Matos da Fonseca 2012). Indeed, temperature affects available capacity of the line, but we restrict our analysis to nominal capacity values. For example, Matos da Fonseca (2012) showed that an ACSR conductor (Aluminium-conductor steel-reinforced cable) of 200 mm^2 can two-fold its nominal current at wind speeds of 5.5 ms-1. The nominal capacity underestimates the capacity for windy days and overestimates the capacity for sunny days. Since we are interested in determining the available capacity for high wind penetration, using the nominal line capacity will overestimate the expected wind spill.

We quantify wind spill for different wind capacity additions and reinforcement scenarios for one region. 'Wind spill' at a particular moment in a 'local system' is the amount of wind power that cannot be fed to the grid, because local power surpasses connector's line capacity, i.e. system capacity (C_s).

We define wind curtailment (Cur) as the percentage of total wind generation that is spilled over a year, or over the time horizon for which one has gathered massive, relevant data:

$$Cur = \frac{wind\ spill}{wind\ generation}$$

$$Cur \sim f(d, C_p, C_s)\text{, where:}$$

$$d = \text{demand}, C_p = \text{Wind power installed capacity}, Cs = \text{local system capacity}$$

This analysis does not consider other causes of wind power curtailment such as ramping or reserves requirements. In addition, demand has a limited impact on curtailment, since in this particular analysis there could be high wind curtailment at times of high demand and high wind resource. Given the current economic downturn of Portugal and the long-term financial constraints under agreement with the E.U. Commission, we assume that electricity demand will not increase significantly by 2030. Thus, we model the case in which demand is equal to 2012.

Then, we estimate *Cur* for different local system capacity values, varying wind capacity from current 2012 levels up to 100 MW.

We estimate connection costs for different system capacity reinforcements, taking into account which element of the system presents the bottleneck, and the discrete grid capacity additions that can be put in place. To do so, we determine the feasible reinforcements of the transformer and the line, for each region analyzed.

The investment decision depends on system reinforcement costs, system capacity, resulting curtailment and tariff paid per unit of electricity fed. The profit function is:

$$Profit\ = Revenue - Cost\ \ \sim f(C_p, C_s, tariff)$$

$Cost = LCOE * wind\ gen$, where:

$$LCOE = \frac{(CCR * [I + total\ connection\ costs])}{wind\ gen} + O\&M$$

CCR is the capital recovery rate, $\left(\frac{r}{1-(1+r)^{-lifetime}}\right)$, where *r* is the discount rate and *lifetime* is 20 years.

I: Total investment costs ($), $I = -3 \times 10^{-4}\ C_p + 164$ [C_p in kW] (using upper and lower bounds from IEA 2010)

$Revenue = Tariff * wind\ fed$ ($)

$wind\ fed = wind\ gen - wind\ spill$ (MWh)

From the investors' perspective, the optimal level of reinforcement will maximize their profits. We build a discrete decision space for the most representative alternatives, and discuss the attractiveness of each option.

4.5 Data

Our data consists of the real power in the transformer of one substation of EDP Distribution, and real wind power generation of one wind park with a 15-minute resolution for the year 2012 (EDP 2013) and grid investment costs (EDP 2013). All data were provided by EDP Distribution. EDP Distribution also provided blueprints of the substation. Other schemes or elements were defined as modeled in DPlan libraries.

4.5.1 Power generation and demand

4.5.1.1 Region 1

Figure 22 shows the capacity factor distribution and Figure 23 shows the local demand distribution connected to transformer 1.

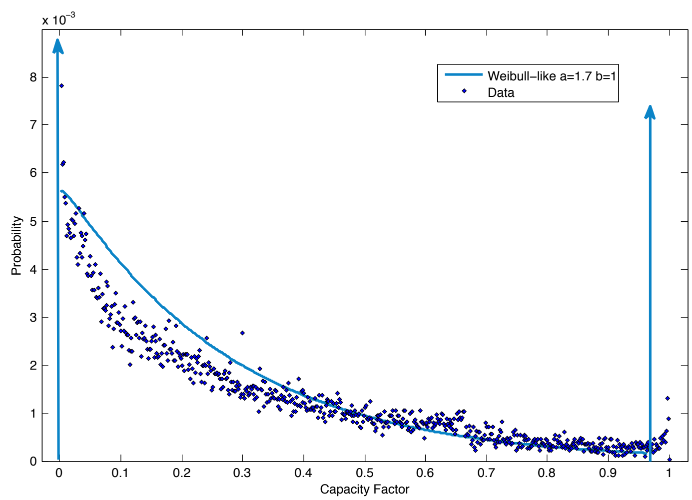


Figure 22 Capacity factor of existing wind park, connected in region 1 in 2012, and a Weibull conditional PDF fit.

Conditional to the fact that wind turbine must be operating in its linear region. Wind power output equal to 0 MW and above 6 MW is assumed to correspond to wind speeds out of the linear operation regions. The two arrows at zero and 0.97 correspond to the frequency of points of generation equal to 0 MW and above 6 MW (up to 6.21 MW), which are the assumed bounds of the linear operation region of the wind turbine.

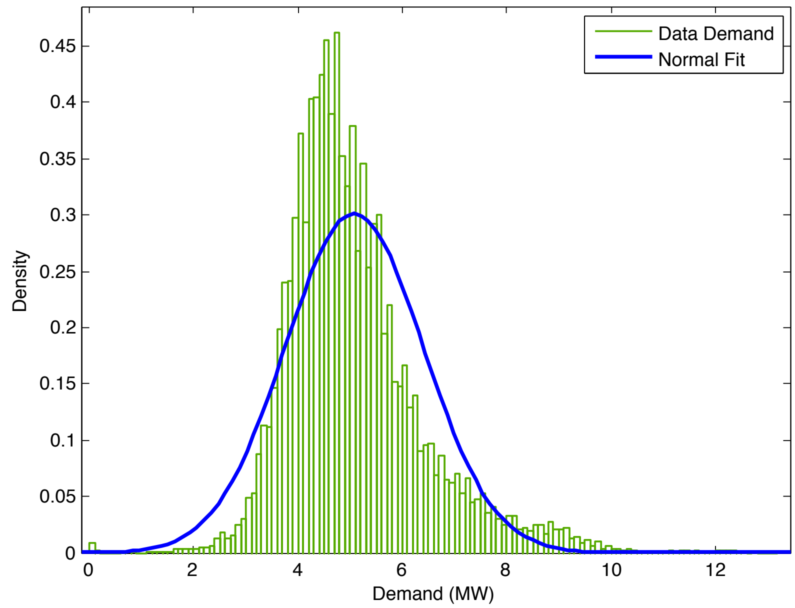


Figure 23. Demand of region 1 in 2012 and fit of normal distribution.

4.5.2 Grid connection costs:

The maximum size of a power plant connected to 60kV is 100 MW. We determine the maximum reinforcement of the line and transformer capacity depending on the existing capacity of power plants. In region 1, there is only one wind park, and as such we consider the reinforcement of the distribution line up to a capacity equal to 100 MW (currently of 20 MW).

4.5.2.1 Total Direct Transformer costs

We consider the full cost of a new transformer for each defined nominal capacity. Figure 24 shows the linear fit of the total cost, as a function of the nominal capacity. We assume that the nominal capacity of the transformer is the maximum capacity that it can hold, because we do not make considerations about losses and optimal point of operation –which usually is at half of nominal capacity or at the point where copper and iron losses are approximately equal, and we neglect reactive power (i.e. we assume a power factor equal to 1). In reality, transformers can hold more than their nominal capacity and operate under normal conditions if temperature is controlled with good ventilation (WEG 2010).

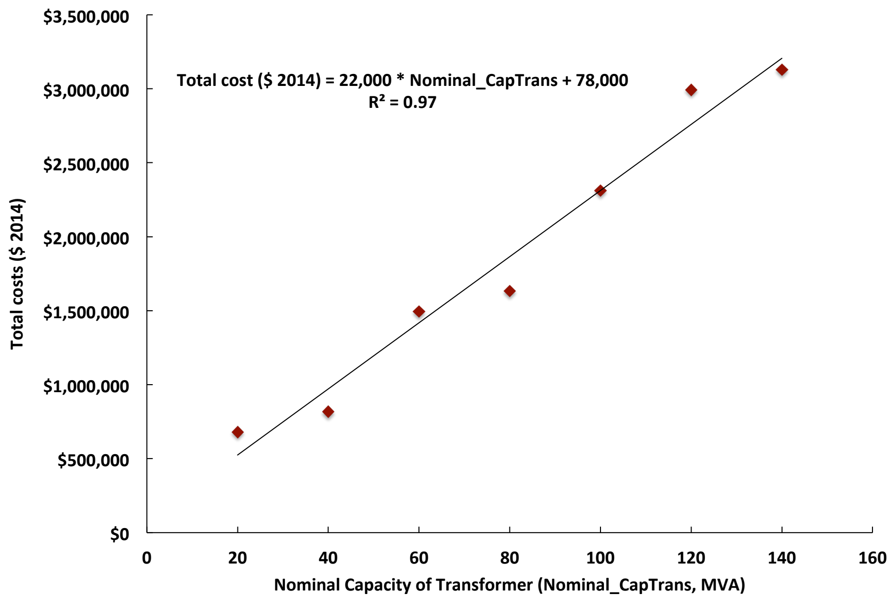


Figure 24 Transformer costs (EDP 2013).
Original values in euros, and exchange rate used equal to 1.36 dollar/euro.

4.5.2.2 Total direct Distribution Line costs

4.5.2.2.1 Region 1

Table 11 shows the alternatives of upgrading line capacity in region 1. Column two describes the options, column three lists the costs per km and column four lists the costs of the fixed poles that have to be installed at the end of the line. The nominal capacity listed is based on nominal current that the conductor can hold at 60 kV. In reality, the capacity of the line is larger than its nominal capacity on windy days or during winter, because the conductor is cool.

Figure 25 shows line costs as a function of nominal capacity, and the linear fit. Alternative number five in Table 11 (the double ACCR line) is still more expensive than alternative number three (the double 545 A line), even though it has a lower nominal capacity. The feasibility of alternative five depends on specific contracts with the line provider that lower the cost but, for this case, the traditional lines are cheaper (see last column Table 11).

Table 11 Description of alternative distribution lines for region 1 (EDP 2013)

Option@ 60kV	Description	Costs/km	Fixed poles installed at the end of the line	Nominal capacity (MVA)*	Total costs per MVA
0	Existing line, 360 A	$61,000	$41,000	37	$16,000
1	Double 360 A	$95,000	$48,000	75	$12,000
2	Single 545 A	$82,000	$41,000	57	$14,000
3	Double 545 A	$122,000	$61,000	113	$11,000
4	ACCR, 408 A	$82,000	$41,000	42	$19,000
5	Double ACCR, 408 A	$163,000	$41,000	85	$18,000
6	New line, 360 A not parallel	$61,000	$41,000	75	$15,000

*Nominal capacity due to current. MVA refers to mega volt-amps, and is included here instead of MW because the nominal capacity takes into consideration apparent power. In our case, apparent power was less than 5% of total power. Thus, we assume it was negligible and nominal capacity would refer only to real power, i.e. for this analysis grid capacity in MVA equals grid capacity in MW.

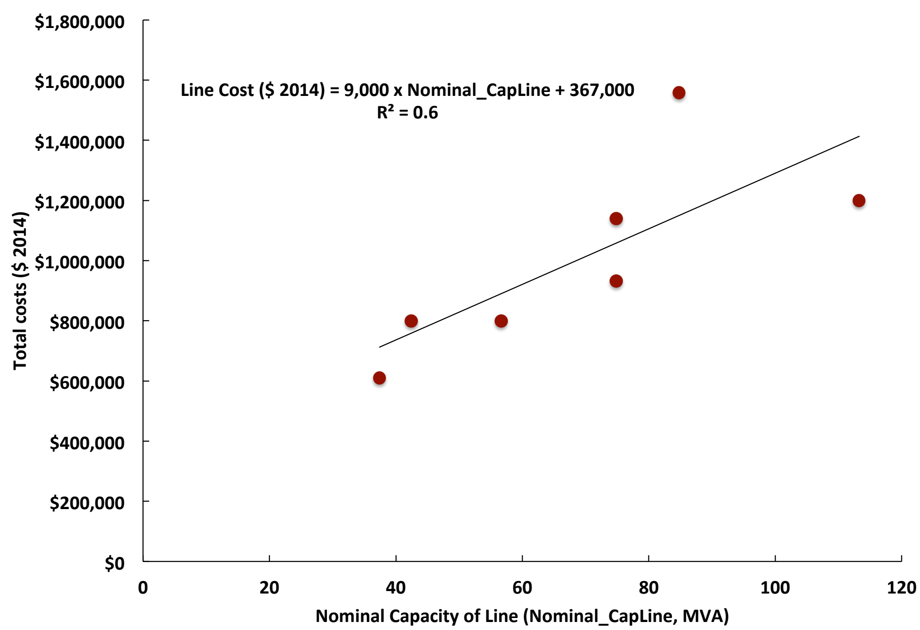


Figure 25 Distribution line costs for region 1
Source (EDP 2013)

4.5.2.3 Total connection cost

We build total connection cost as a function of the resulting system's total nominal capacity, equal to the sum of the cost of the distribution line and the transformer cost. Figure 26 shows the linear fit of total connection cost. Our connection costs are consistent with those reported in the literature. For instance, Mills et al. summarizes the transmission cost per kW of wind from a sample of 40 transmission studies between 2001 and 2008 in the U.S. (Mills et al. 2009). The range of costs reported is \$0-\$1,500/kW. Portuguese transmission costs for the alternatives considered range between \$45 and \$217/kW of wind power installed, assuming the wind power developer will never over-invest in the grid capacity. If the wind power developer builds lines with transmission factors higher than 1, the Portuguese costs used in this study range between \$45 and \$750/kW.

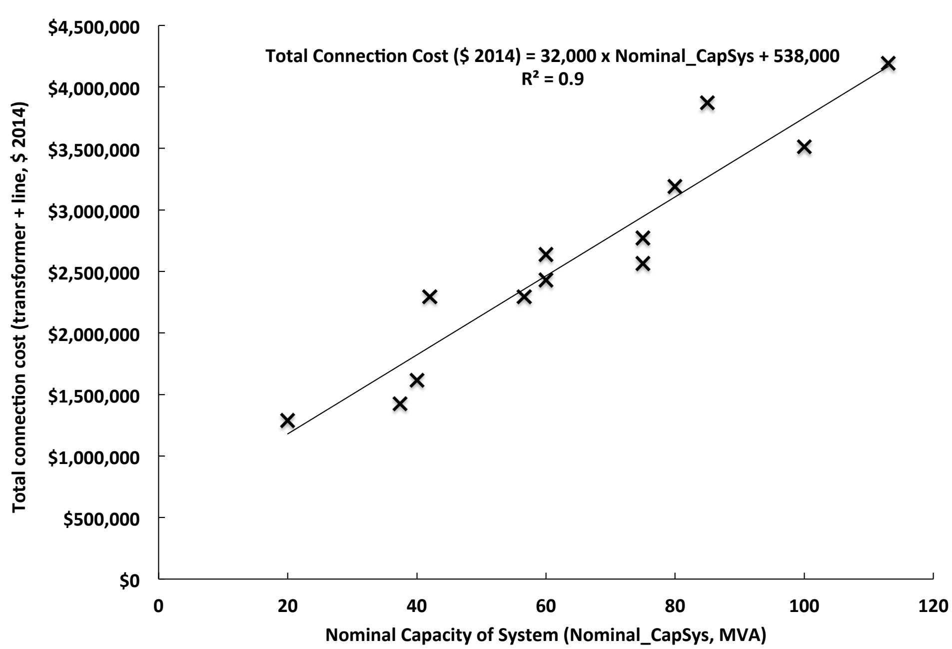


Figure 26 Total Connection Costs for region 1.

4.6 Results

4.6.1 Region 1

4.6.1.1 System Characterization

For region 1, we estimate wind spill in one of the lines, according to the configuration of the substation as shown in Figure 27.

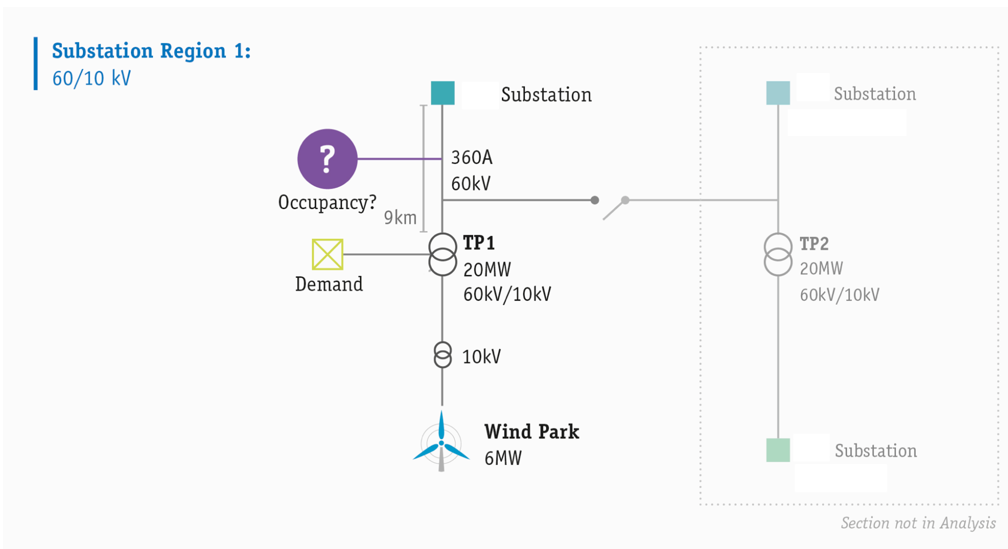


Figure 27 Scheme of region 1.
TP1: Power Transformer number one. Figure based on blueprints provided by EDP. For region 1, the current nominal line capacity is 37 MW and the transformer capacity is 20 MW. Thus, the bottleneck is the transformer, and the system's capacity is *Cs*=20 MW.

For transformer 1 (TP1 in Figure 27), the power that cannot be fed in the system corresponds to the wind spill, and is equal to:

$$Wind\ spill = \begin{cases} 0 & \text{if } \{C_s - abs[d - wind\ gen]\} > 0 \\ abs[d - wind\ gen] & \text{if } abs[d - wind\ gen] \leq 0 \end{cases}, \text{ where:}$$

$$wind\ gen = C_p * capacity\ factor_{instant\ in\ 2012}$$

In a year, total wind power curtailment corresponds to:

$$Cur_y = \frac{Wind\ spill_y}{Wind\ gen_y} = \frac{\sum_{i=0}^{4\times 8760} \frac{1}{4} \times Wind\ spill_i}{\sum_{i=0}^{4\times 8760} \frac{1}{4} \times Wind\ gen_i}$$

$$Cur_y = \frac{\sum_{i=0}^{4\times 8760} \frac{1}{4} \times \begin{Bmatrix} 0 & \text{if } \{C_S - abs[demand - wind\ generation]\} > 0 \\ abs[demand - wind\ generation] & \text{if } abs[demand - wind\ generation] \leq 0 \end{Bmatrix}_i}{\sum_{i=0}^{4\times 8760} \frac{1}{4} \times \left(C_p * capacity\ factor_{2012}\right)_i}$$

Table 12 shows the resulting frequency distributions (larger versions of the figures are in the Supplemental Information) if no grid reinforcements are made. The left column depicts the case of today's installed wind capacity (6 MW); the right column assumes the maximum possible future capacity has been installed (100 MW). We assume local power demand remains as in 2012, which overestimates wind power curtailment compared to a demand increase scenario.

Today (left column of Table 12), the wind park is generating in average 1.5 MW of power every 15 minutes. Electricity generation is zero during 16% of the year, and at its maximum less than 0.2% of the year. Given the local demand profile, there is ample room in the system to receive the wind electricity produced, even at moments when local demand is absent. In fact, the minimum grid capacity available is approximately 6 MW out of the 20 MW of nominal available capacity, meaning that there are, at maximum, only 14 MW used. Only nine hours out of the whole year more than half of the system capacity is employed (0.1% of the time).

The last row in Table 12 shows the capacity factor of the wind electricity fed to the system. Today, all wind electricity generated is fed to the grid, which is why this function mirrors the function of wind power generation. The average capacity factor is 0.24; 83% of the time, it is below 0.5.

If wind power capacity increases up to 100 MW (the rightmost column in Table 12), and no grid reinforcements are undertaken, the system capacity will be fully occupied 37% of the time, assuming 2012 annual wind resource and power demand profiles remain unchanged. All of those fully occupied moments will entail some wind power curtailment. Therefore, the resulting capacity factor frequency distribution function no longer mirrors wind power generation, due to the limited line capacity. The average capacity factor will decrease to 0.14, and will remain below 0.33. Total electricity curtailment under this extreme scenario will amount to 41% of total annual generation.

We compare the distribution line of region 1 with one of the most occupied distribution lines at national level, in Cabril region (see Figure 21). If wind power capacity doubles at national level during a representative windy day in history (December 14^{th}, 2012), the line analyzed presents no risk of full occupancy, and an average occupancy of 9% (with standard deviation equal to 7%). For the same case, the line in Cabril region presents full occupancy 1% of the time, period during which at most 6% of the wind power is spilled. This means that the total wind power spilled is approximately 0.06%. Thus, even one of the most occupied lines present very little occupancy. More details on how the line analyzed compares to the most occupied lines can be obtained if similar wind power targets are analyzed in such regions. For example, increasing wind power capacity 16 times compared to 2012 levels in Cabril region would provide results that compare directly to the case of connecting 100 MW in region 1.

All the cases between 6 MW and 100 MW of wind power in region 1 are compiled in Table 13. The column to the left shows a graph with average estimates of wind power curtailment as a function of wind capacity additions in 10 MW steps, and the column to the right shows the resulting capacity factors. Four curves, representing different system total capacities, are shown. Larger improvements are seen for system upgrades in the lower scales. For example, a system capacity increase from 20 MW to 37 MW (i.e. increasing the nominal capacity of the transformer without changing the lines, which can be achieved with good ventilation of the existing transformer) has a remarkable impact: wind power will increase up to 100 MW and total wind power curtailment will decrease from 41% to 20%, i.e. resulting in an improvement of average capacity factor from 0.14 to approximately 0.2. Moreover, a curtailment of 41% of wind production yields negative returns, but a curtailment of 20% yields positive returns, making a small grid investment critical for the investment decision. If subsequent investments in the grid are made, wind power curtailment decreases. For instance, for 100 MW wind capacity installed, a system with 50 MW will entail a wind total annual electricity curtailment between 7% and 16%. A system with nominal capacity of 60 MW can hold 94% of all wind power generation while one of 80 MW can hold 99% of all wind production.

Also, as shown in the right column of Table 13, installed wind power capacity can exceed system's nominal capacity with no risk of wind power curtailment. For instance, if a maximum of 5% of total power curtailment is allowed, systems with nominal capacities of 20 MW, 37 MW and 60 MW will be able to connect 38 MW, 65 MW and 95 MW of wind power capacity, respectively. This means that a tolerance of 5% of power curtailment can allow wind power capacity additions of at least 1.6 times the system's nominal capacity.

Table 13 also shows the associated costs for the different alternatives of the wind investor. The first case is the status quo. If the wind investor does not upgrade the distribution line, i.e. the grid capacity ranges between 20 MW and 37 MW (upper limit determined assuming good ventilation in the transformer), wind power capacity additions of 94 MW (to reach 100 MW) will incur lost revenues between $5 million and $10 million, annually, assuming no change in FIT level from that established in the latest legislation of February 2013. If instead, the investor decides to upgrade the grid to 80 MW (assuming a 1% tolerance of wind curtailment), the balance is a lower annual net cost of less than $1 million.

Table 12 Distribution of wind power and grid resource in region 1, if no grid reinforcements are made.

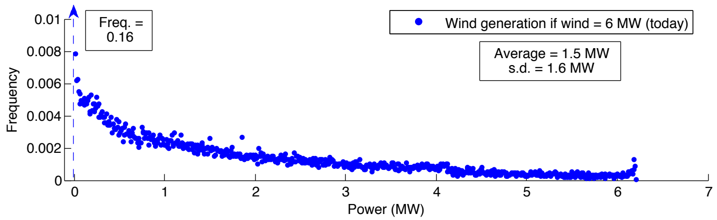
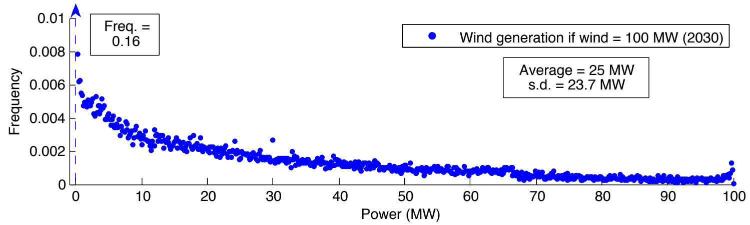
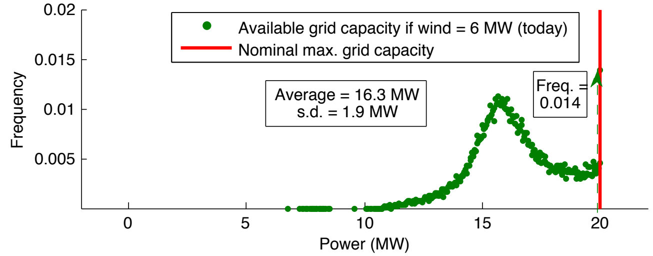
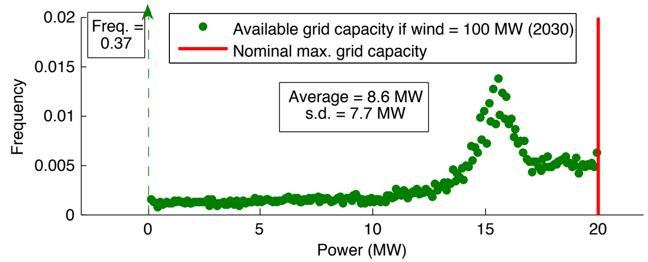
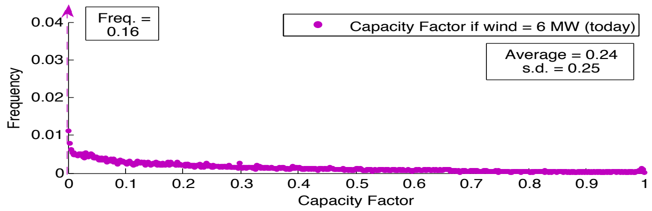
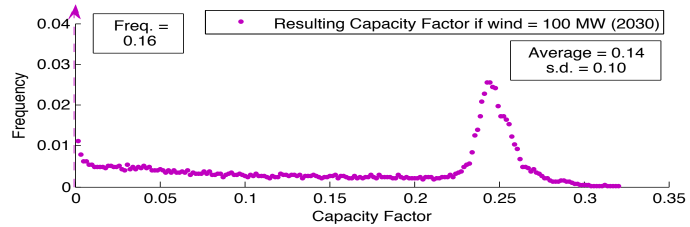
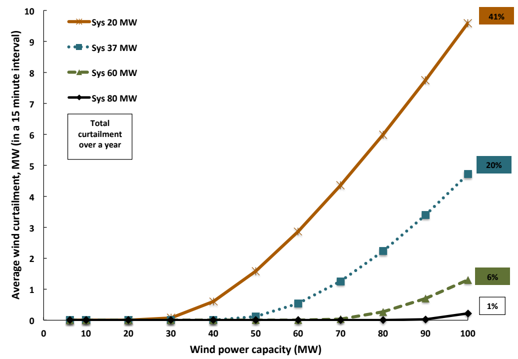
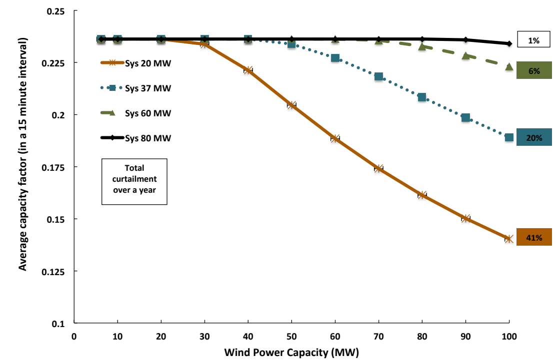
		Wind Capacity Installed = 6 MW	Wind Capacity Installed = 100 MW
Power Demand as in 2012 No Grid Reinforcement	Wind power generation (MW)	 Mean: 1.5 MW, Standard Deviation: 1.6 MW. Total wind generation: 12,900 MWh.	 Mean: 25 MW, Standard Deviation: 23.7 MW. Total wind generation: 207,500 MWh.
	Available Grid Resource (MW)	 Mean: 16.3 MW, Standard Deviation: 1.9 MW.	 Mean: 8.6 MW, Standard Deviation: 7.7 MW.
	Capacity Factor	 Mean: 0.24, Standard Deviation: 0.25. Total power pumped-in the grid: 12,900 MWh. Wind electricity curtailment: 0%.	 Mean: 0.14, Standard Deviation: 0.10. Total power pumped-in the grid: 123,300 MWh. Wind electricity curtailment: 41%.

Table 13 Associated costs in region 1. Losses in revenue coming from wind curtailment and lower resulting capacity factor.

	Wind Curtailment	Resulting Capacity Factor
Figures		
No reinforcement. System capacity = 20 MW-37 MW. Wind capacity = 100 MW.	**Costs:** Grid reinforcement costs = $0 **Annual electricity generation**=208,000 MWh. **Annual electricity fed**=125,000 MWh to 165,000 MWh. **Tariff paid (in 2011) =** 121/MWh (IEA 2012). **Annual revenue lost:** $5 million to $10 million (depending on ventilation of transformer). **Total annual extra cost:** $5 to $10 million (i.e. $24-$48 MWh-produced)	
Reinforcement. System capacity = 80 MW. Wind capacity = 100 MW.	**Annual grid reinforcement costs:** approximately $0.5 million (i.e a total of $50/kW-installed (EDP 2013)). **Annual electricity generation**=208,000 MWh. **Annual electricity fed**=205,000 MWh to 208,000 MWh. **Tariff paid (in 2011) =** ¢ 12.1/kWh (IEA 2012). **Annual revenue lost:** up to $0.3 million (depending on ventilation of transformer). **Total annual extra cost:** approximately up to $0.8 million ($5/MWh-produced).	

4.6.1.2 Investment Decision

Figure 28 shows the change in net present values (NPVs per MWh) as grid capacity increases for the representative cases illustrated in Table 13. The most profitable option (per MWh) from the investor's perspective is to connect 100 MW of wind power and upgrade the grid capacity to 100 MW. This is similar to the alternative of not incurring additional grid investments and adding wind power capacity up to the value for which no curtailment is expected, i.e. up to the local system capacity of 20 MW.

For each wind power capacity case, maximum profits are achieved at 0-1% wind power curtailment. Ensuring strictly no wind power curtailment represents grid upgrades that have very little utilization. For example, the current case in which 6 MW are installed and the system has a local capacity of 20 MW entails a NPV of $15/MWh. Further grid capacity additions would lead to increased costs and no added benefit.

NPVs can increase when wind power increases, even if the resulting wind spill is higher. For example, for the case when grid capacity equals 37 MW, and wind capacity increases from 20 MW to 50 MW, wind power curtailment will change from 0% to 4%, and NPVs will also increase from $16/MWh to $17/MWh. A further increase in wind capacity up to 100 MW will yield lower NPVs because the wind spill of approximately 20% results in lower revenues per MWh generated.

Figure 28 also shows that alternatives with high curtailment are profitable. For example, the case of wind power capacity of 50 MW and system capacity of 20 MW, and the case of wind power capacity of 100 MW and system capacity of 37 MW, result in wind curtailment of more than 10%, and NPVs over $10/MWh. This will not maximize investors' return, but it does highlight that investments are profitable due to the large revenue received in the form of FITs. It is important to notice that the level of wind spill that still results in positive NPVs is particular to this region, because the length of the grid line is about 9 km –i.e. grid capacity investment upgrades are relatively low compared to wind power investments.

Other regions might need to invest in longer lines and higher capacity upgrades that can make them more sensitive to wind curtailment. For instance, if the nominal capacity of the system analyzed was half of today's, NPVs will decrease for a wind capacity of 20 MW from $16/MWh to $14/MWh due to a small expected wind power curtailment of 2.5%.

For all the cases analyzed, returns to investment (ROIs) are as high as 40%. Thus, revenues to the wind investors could in fact be limited. ROIs could be reduced by two mechanisms. The first and most obvious is to reduce total revenues, i.e. decrease the level of the FIT from $100/MWh to approximately $80/MWh. This reduction will not have an impact on the order of the best investment decision, i.e. the best decision is still to upgrade the grid up to the minimum capacity required to ensure less than 1% wind power curtailment. Reducing the level of the FIT will instead decrease returns for all cases. Thus, it will make cases of more than 10% wind power curtailment no longer profitable, and it will also reduce the difference in ROIs between the options. In other words, all alternatives will be clustered closer around a lower value, which can in fact reduce the tolerance of the investor for wind power curtailment. For example, a 100 MW wind capacity goal and upgrades of the grid up to 60 MW and 80 MW entail wind power curtailments of 6% and 1%. If the FIT is high and equal to $100/MWh, the resulting ROIs are of 33% and 38%, respectively. If the FIT decreases to $80/MWh, ROIs are of 8% and 12% instead. Thus, a wind power curtailment of 6% will significantly reduce the ROI (30% reduction, from 12% to 8%) under a low FIT, compared to a moderate reduction under the high FIT scenario

(13% reduction, from 38% to 33%). In fact, the 6% wind power curtailment scenario and low FIT will probably not be attractive to the investor.

Due to the role that the current FIT plays in the troika agreements that cover today's electricity deficit, and the economic importance of wind developers in Portugal, the alternative to limit FIT payments is not popular; it might not be feasible to reduce the level of FITs. Thus, the other option is to limit returns for investors, by allowing for wind curtailment over 1%. This will result in a higher occupancy of the system because further grid investments will be avoided. For example, if the maximum NPV allowed is $10/MWh, a connection of 50 MW of wind power will not incur extra grid investments (i.e. system capacity equal to 20 MW), and a connection of 100 MW of wind power will only need to reinforce - or ensure enough ventilation of the existing transformer (i.e. system capacity equal to 37 MW). The wind power curtailment under these options will be 13% and 20%, compared to 1% curtailment achieved if grid reinforcements are made and larger Return on Investments (ROIs) are allowed.

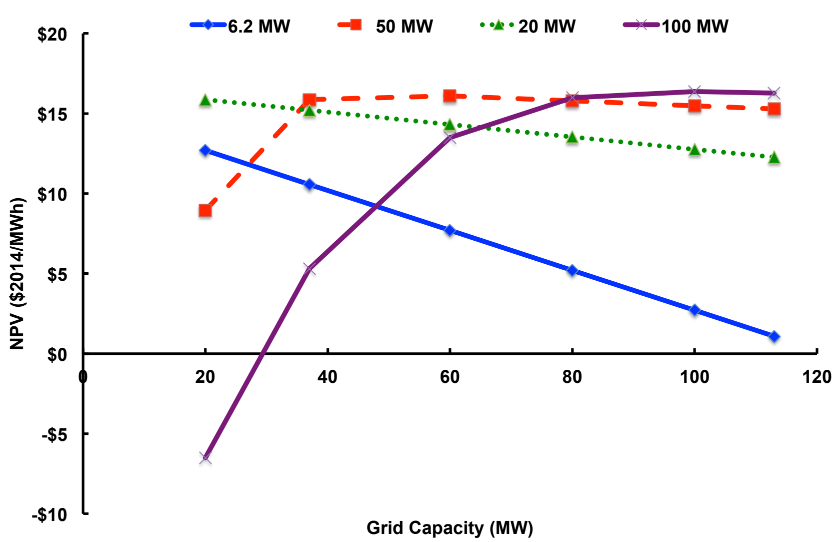


Figure 28 NPVs ($/MWh) for grid capacity upgrades under four alternatives of wind power capacity installed in region 1.

Today corresponds to the case: Wind Power Capacity = 6.2 MW and Grid Capacity = 20 MW. Assumptions: Investment costs of $1.8 million/MW installed, grid reinforcement costs as shown in section Data. 20 years lifetime, 10% discount rate, O&M costs $5/MWh, exchange rate 1.36 dollar/euro.

4.6.1.3 *Impacts of wind power curtailment in the minimum FIT*

In Chapter 3 (and published in Peña et al. 2014) we estimated the minimum FIT[22] required to achieve NPVs=$0/MWh. For that case, we found that holding all factors constant (investment costs, O&M costs, lifetime, discount rate and payback period), a decrease of 10% in capacity factor reduces NPVs from $0/MWh to -$3.3/MWh. Thus, the effect of including a 10% wind curtailment is that the minimum 20-year FIT would need to increase from $75/MWh to approximately $83/MWh. On the other hand, allowing for wind power curtailment also reduces investment costs, since reinforcement of distributions lines, a cost borne by wind investors (EDP 2013), is no longer necessary. Investment costs need to decrease by 8% to offset the capacity factor impact in NPVs at the minimum FIT.

4.7 Conclusions and Policy recommendations

Directive 2001/77/EC, reflected in subsequent Portuguese Decree Laws, established that renewable energy generation must be prioritized and grid access should be guaranteed to all renewable electricity generation, including wind power.

Under the current scheme's design, wind IPPs are guaranteed to sell all generated electricity and bear no risk of electricity curtailment (also called wind spill). In other words, wind power producers can feed all the amount of electricity they produce into the grid. This requires having sufficient transmission and distribution grid capacity to receive all power generation under the worst-case scenario -when power production is at its peak and demand is minimal. But

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[22] The minimum FIT was estimated over 20 years, for an average national capacity factor of 0.24, which is the same capacity factor of region 1. The minimum FIT is $75/MWh assuming investment costs of $1.27 million/MW [IEA average estimates for Portuguese investment costs in 2010].

maintaining an electric grid for zero congestion can be very expensive and cost-ineffective. In fact, wind investors will maximize their profits if some wind curtailment is allowed, which allows grid investments to drop significantly. For region 1, their investment decision will have a 1% wind curtailment tolerance. Wind curtailment can as well offer the alternative to policy makers of limiting revenue of wind investors - if FIT levels cannot be reduced. For instance, allowing for wind power curtailment of as high as 20% in region 1 can in fact reduce ROIs from about 40% to 14% if 100 MW are installed.

At this stage of wind energy deployment, where wind power covers 20% of demand in Portugal, planning network capacity for zero wind power curtailment is a very conservative policy approach: it not only results in line investments with little occupancies, but also restricts access to connection lines, limiting the availability of sites. Instead, if Portugal reevaluates the capacity limit barrier for distribution lines, more wind power can be connected to lines that are currently classified as "occupied".

We estimated the resulting wind power curtailment and the decrease of capacity factors associated with different grid upgrades in a 60 kV line for subsequent wind power additions. We found that there is currently enough capacity in the distribution grid to take more wind power additions at the 60 kV level. For region 1, a fifth or more of the system capacity is used less than 21% of the time. The rest of the time, the system has up to 80% of free capacity to transport generated wind electricity. This is a conservative estimate: a dynamic model of the line considering temperature, and assumptions of increasing demand would result in even lower occupancies. If the grid operator allows wind power additions of 1.6 times region 1's nominal capacity, this would result in wind power curtailment of less than 5%. If no investments in grid upgrades are made, and wind power capacity in region 1 increases to 100 MW, total wind power curtailment over a year is approximately 20-40%.

In terms of grid investment decisions, wind producers face a relatively small extra investment cost to upgrade the distribution grid and avoid wind curtailment. From the investor's perspective, we find that: 1) The optimal investment has a 1% wind curtailment tolerance, i.e. it is better for the wind investor to face a 1% wind power curtailment than make additional grid investments. 2) A wind curtailment of 1% still allows for a lot of wind power additions –mainly due to today's excess grid capacity. For example, in region 1, approximately 35 MW of wind power could be added to achieve a total installed capacity of about 40 MW with no grid upgrade, and feed about 99% of all wind production. 3) The maximum wind power capacity addition (reaching 100 MW of wind power installed) with no further grid upgrades results in a curtailment of about 20-40%. In this case, the annual revenue lost due to curtailment ranges from \$5 to \$10 million, and such high curtailment rates eliminate the profitability of wind capacity additions. From a public policy perspective, we find that 4) wind power curtailments as large as 20% still result in profitable investments and returns to investment of at least 14%, which implies that the level of the current feed-in tariff offered is high.

4.8 Supplemental information

4.8.1 Impacts of wind power in the power demand

Even though Portugal has reduced its fossil-fuel power generation –from 64% of total electric power demand in 1994 to about 53% in 2012 (DGEG 2014), the ambitious renewable power goals established until 2030 and the relative small expected demand increase (DGEG & REN 2013), might create a surplus of electricity capacity and generation. The national energy plan for 2020 and 2030 is to add more natural gas, cogeneration and renewable power capacity – including 4 GW of reversible hydropower and 2 GW of wind power, and phasing out the remaining two coal power plants. In addition, the grid connection capacity with Spain is limited between 1,600 MW- 2,000 MW[23]. By 2011, the Net Transfer Capacity (NTC) was 90% of the time between 1,500 MW and 2,200 MW (REN 2013a). Even though it is expected to be reinforced up to 3,000 MW (DGEG & REN 2013), there is no anticipated new connection capacity with the rest of Europe, which limits the amount of Portuguese electricity that can be traded.

A detailed analysis on power profiles for 2030 would consider a description of the stochastic processes for wind, hydro and demand, and would incorporate time-dependency correlations. Because it is beyond the scope of this section to perform such an analysis, we perform a statistical analysis using 15-minute data for four representative weeks of 2012 and 2013 (REN 2013b; DGEG 2014) and present the lower and upper bounds for expected exports for year 2030, and for a week and a day in 2030 under historical maximum resource conditions, i.e. when the

[23] The minimum most probable reported values (by December 2012) are: Direction Portugal to Spain: 1,700 MW all year long. Direction Spain to Portugal: 2,000 MW during summer and 1,600 MW during winter. The new line (expected to be functioning by 2014) Algarve-Andalucía of 400 kV will increase capacity Portugal to Spain to 2,800 MW, and Spain to Portugal to 2,200 MW.

hydro index[24] was 1.90 -the highest value since 1970, and the wind index was 1.66 -the highest of all times for that period[25]. Thus, this analysis presents the range of power generation by source, but does not show anything about the probability density distribution of power generation.

Figure 29 shows as bars annual electricity generation and imports between 2000-2012, disaggregated by source, and an estimate for 2030 (DGEG 2014; DGEG & REN 2013). The share presented in 2030 by source corresponds to the generation using capacity factors of year 2012, and assuming Portugal achieves its power capacity goals for 2030 (DGEG & REN 2013). The upper and lower bounds for generation presented depend on minimum and maximum observed capacity factors of four representative weeks of 2012 and 2013[26], and demand in 2030 is assumed to be equal to 2012. We found that the estimated extra power capacity will not necessarily create an electricity surplus in 2030 because the extra hydro reversible power capacity will serve as storage capacity. The lower total electricity generation happens under a low renewable resource scenario, in which gas power and cogeneration need to supply a larger share of demand. In that case, under the capacity goals of 2030, about 40% of electricity demand will be met through imports. If weather conditions in 2030 are comparable to those in 2012 (a dry but exceptional windy year), only 14% of electricity demand will be covered through

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[24] Wind and hydro index are a measure that compares the historical available resource with the current resource, over a specific period –usually weekly or monthly based.

[25] This happened in the week March 27th-April 2nd. During one day of the week, wind and hydro attained simultaneously .88 and .74 of full capacity use.

[26] We analyzed the months of 2012 and 2013 with critical conditions, i.e. with high wind and high hydro generation, high wind and average hydro generation, average wind and high hydro generation and average hydro and average wind generation. After, we chose four representative weeks and analyzed the power profiles using 15-minute resolution data. We looked only at years 2012 and 2013 because there have been recent new capacity additions and special conditions happened. For the selection of the weeks, we used the wind and hydro indexes, measures to reflect the variation of monthly generation around the annual average generation (REN 2013a; APREN 2013). For example, a wind index of 1 means that wind generation over a period is equal to the historical average over the same period (usually reported by month by REN).

imports. In the case hydro and wind resource availability is high, Portugal will need to export about 4% of its total generation to Spain.

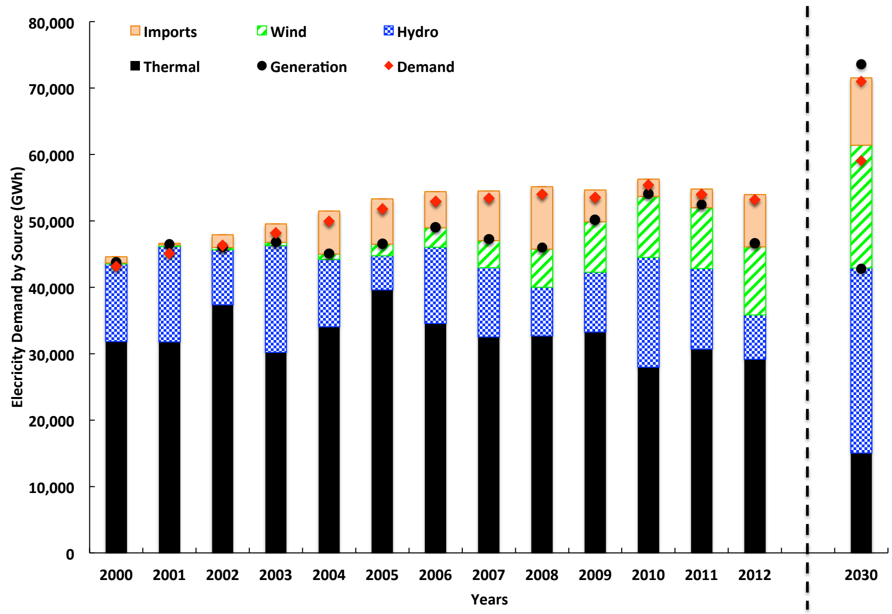

Figure 29 Disaggregation of Portuguese Electricity Generation by Source in 2000-2012. Assumptions for 2030 estimates: capacity factors vary between the annual of 2012, and historical 15-minute values of four representative weeks of 2012 and 2013 to include seasonality. Capacity factors ranges: total hydro 0.14-0.31, Wind: 0.26-0.47, PV: 0.11-0.19, Pumped-hydro: 0.27 (only a low value was used to be conservative in the storage availability), Natural gas: 0.17-0.25, Thermal Special: 0.51-0.65. Coal generation displaced in 2030 assumed to be coped through natural gas. Demand: 1.14 of 2013. The bounds for 2030 do not reflect time-dependence between the generation sources (REN 2013a; DGEG & REN 2013). Column heights and demand (shown as red dots) are slightly different due to system losses.

Figure 30 shows the power profile over a week with average hydro and wind resources (based on the hydro and wind index of the month of December), if the 2030 capacity goals of wind and hydro pumped-hydro capacity are reached, as established by REN and DGEG in the last Energy Plan of 2013. Given that under such resource availability there will be net imports, we conclude that the expected wind power additions will be well integrated with the storage capacity planned.

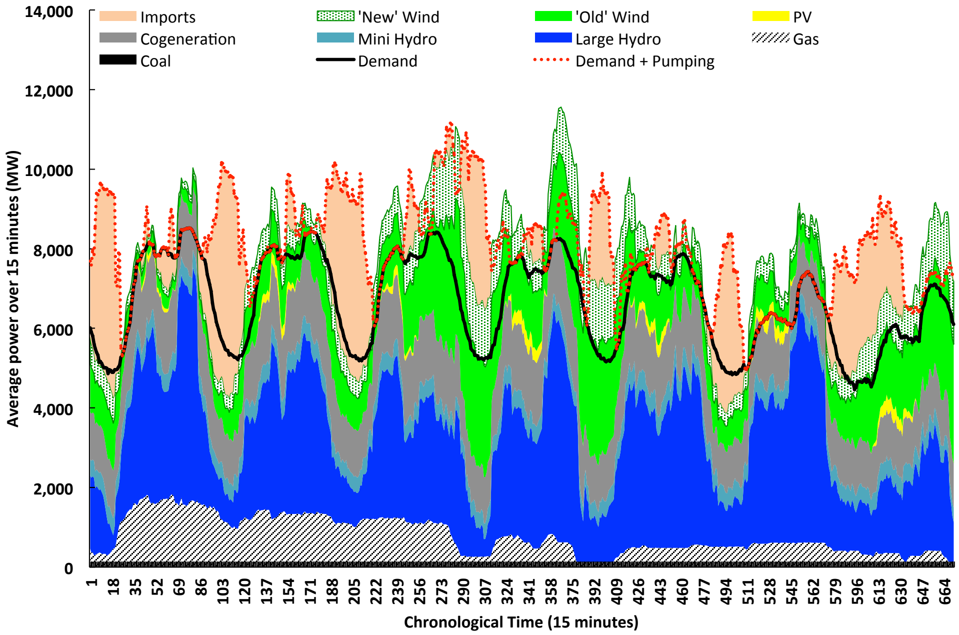

Figure 30 Power profile of a hypothetical week in 2030, using hydro and wind indexes of an 'average' week in 2013.

'Average' means that the week selected had the closes hydro and wind indexes. Historical case for December 17th-23rd, and hypothetical case under the 2030 capacity goals. The 2030 power capacity goals are (in parenthesis installed capacity by December 2012): Large hydro: 9,650 MW (5,239 MW), Small hydro: 620 MW (417 MW), Wind: 6,400 MW (4,194 MW), Solar: 640 MW (220 MW), Thermal Special: 2,660 MW (1,779 MW), Natural Gas: 4,605 MW (3,829 MW). Coal: 0 MW (1,756 MW), Oil: 0 MW (1111 MW).

For the 2030 power profile modeled in Figure 30, hydro pumped-hydro capacity reaches more than 5 GW, and other renewable capacity reaches the specified 2030 goals. We modeled hydro pumped-hydro storage following the same profile as in 2012 and the capacity of 2030. In the figure the light pink area corresponds to imports from Spain. For example, at time point number 100, part of demand is covered through imports –up to the continuous black line that corresponds to demand. The amount up to the red dotted line corresponds to imports that were used for pumped-hydro. The use of stored hydro capacity later on for power generation is then reflected as part of the large hydropower generation (dark blue area). There are also moments when pumped-hydro does not cope with the large generation, and there are some exports to Spain. The balance is net imports equal to about 100,000 MWh, i.e. 8% of total demand (including pumped-hydro).

But even though the total annual generation is likely not to exceed the target demand, the 2030 goals can be challenging at rainy seasons with high wind speeds because all renewables are "must takers" by law (Diário da República 2001a). Consider seasons with high wind and hydro conditions. Although these are rare[27] they prove to be expensive to the system.

For example, in the first three months of 2013, hydro production was four times higher than over the same period in 2012, meeting 31% of demand, and hydro storage was used at .88 of full capacity. During those three months, wind power covered 28% of total demand and all other renewables had better conditions than in 2012 except for solar (a reduction of 9%). The result was that thermal production was at its lowest since 1996, with coal and gas representing 17% and 3% of demand, and there were 6% of net exports to Spain. In this case, the under-utilization of existing fossil power plants and the lower price received for exports compared to the FIT paid for generation represented net costs to the Portuguese Electricity System (SEN).

Shorter periods of analysis provide insights into low-probability events, such as high resource availability. For example, during the week March 27th-April 2nd, 2013, the hydro index was 1.90 -the highest value since 1970, and the wind index was 1.66 -the highest of all times for March[28]. Table 14 shows total generation coming from each source for that week. Table 14 also shows generation assuming the 2030 capacity goals are met and the hydro and wind conditions are as March 27-April 2, 2013, and Figure 31 corresponds to this hypothetical weekly power profile (see SI for details of a week with an average wind and hydro resource availability). The high renewable power generation maintained fossil fuel based generation low. For instance, gas

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[27] We found a low correlation of 0.14 between hydro and wind generation between July 2007-April 2013, i.e. it is not common to have high wind and hydro available resources simultaneously. Because all electricity generation from these sources is taken by the Electrical Grid, electricity generation mirror wind and hydro resources.

[28] During one day of the week, wind and hydro attained simultaneously .88 and .74 of full capacity use.

capacity factor was about 1.5% over the period. Given that fossil-fuel power was operating at low level, the 180,000 MWh of exports can be attributed to wind and hydro production. If Portugal meets its 2030 goals for wind and other power technologies –including pumped-hydro storage, in weeks with these weather conditions there will be about 770,000 MWh of exports.

Table 14 Electricity mix for the worst-case scenario over a week, i.e. highest wind and hydro historical conditions.

Historical case for March 27-April 2, and hypothetical case under the 2030 capacity goals. The 2030 power capacity goals are (in parenthesis installed capacity by December 2012): Large hydro: 9,650 MW (5,239 MW), Small hydro: 620 MW (417 MW), Wind: 6,400 MW (4,194 MW), Solar: 640 MW (220 MW), Thermal Special: 2,660 MW (1,779 MW), Natural Gas: 4,605 MW (3,829 MW). Coal: 0 MW (1,756 MW), Oil: 0 MW (1111 MW).

TOTAL ELECTRICITY (MWh)	Coal	Gas	Oil	Hydro ordinary	Wind	Solar	Hydro special	Thermal special	Exports
March 27 – April 2 2013	33,600	10,000	0	481,700	342,500	5,100	53,200	159,200	176,400
2030	0	96,200	0	887,200	522,700	14,800	79,200	238,100	768,700

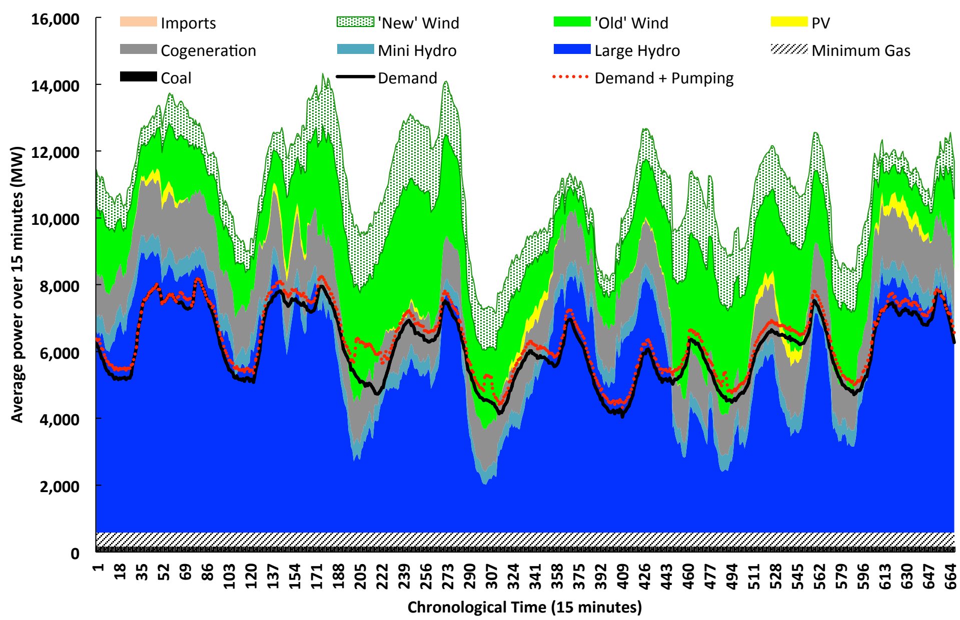


Figure 31 Hypothetical Power Profile of Portugal during a week with exceptionally large hydro and wind resources in 2030.

All production above the dashed black line representing demand (including pumped-hydro) will be exported under the current policy. Instead, if spill of wind generation is allowed, all generation represented in green above demand will not be fed into the grid and will not be exported. Assumptions: wind displaces power in the following order: imports, coal, gas, and thermal special (cogeneration). The minimum thermal power is the power at the historical wind peak (scaled up to total capacity installed in 2030) reported on March 29th, 2013, with 87% of wind power operating at full capacity at 14.45.

4.8.2 Figures in large size for analysis of grid occupancy of region 1

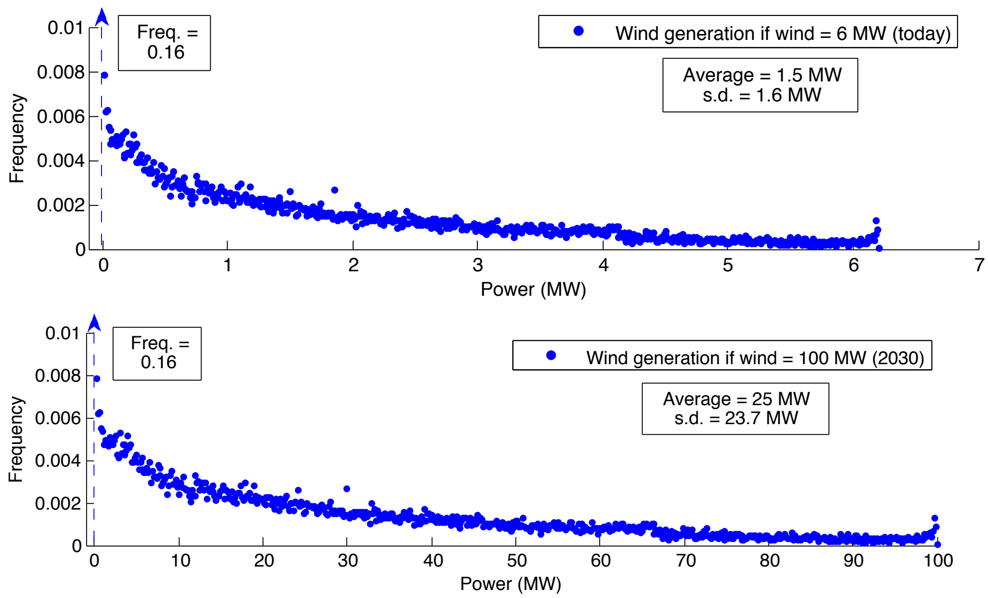


Figure 32 Wind generation distribution (above: today, below: in 2030). Given that the same wind resource distribution of 2012 is assumed in 2030, and the extra capacity additions are assumed not to have any efficiency impact, both distributions present exactly the same shape.

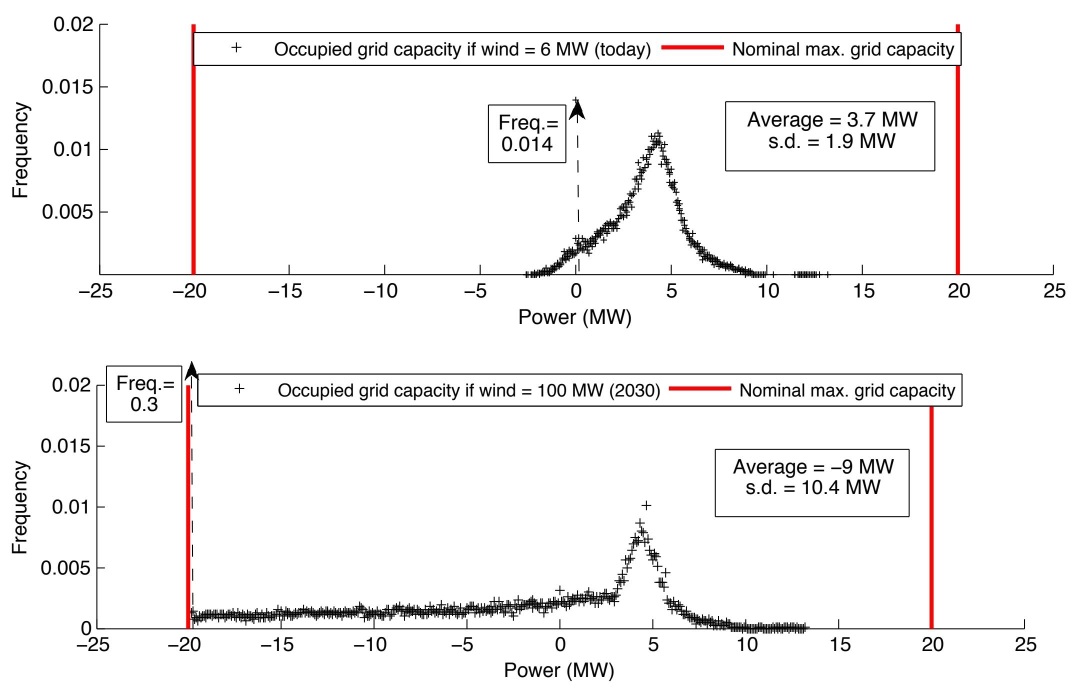


Figure 33. Occupied grid capacity (above: today, below: 2030), if no grid reinforcements are made. The average occupancy of the grid increases from 3.7 MW (direction system to substation) to 9 MW (direction substation to system) as wind capacity installed increases from 6 MW to 100 MW.

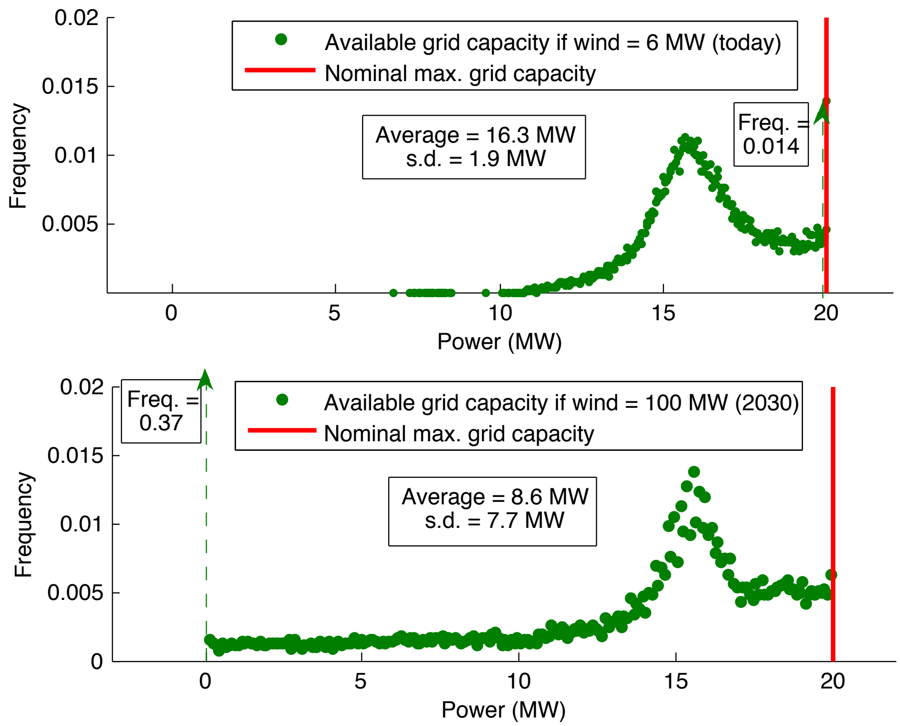


Figure 34 Available grid capacity (above: today, below: 2030), if no grid reinforcements are made.

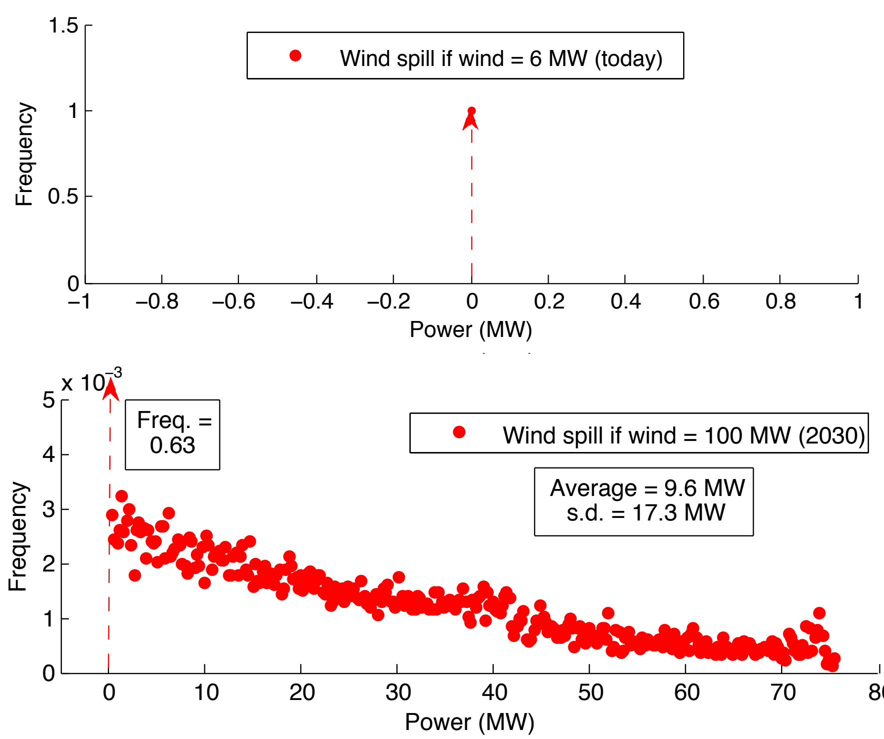
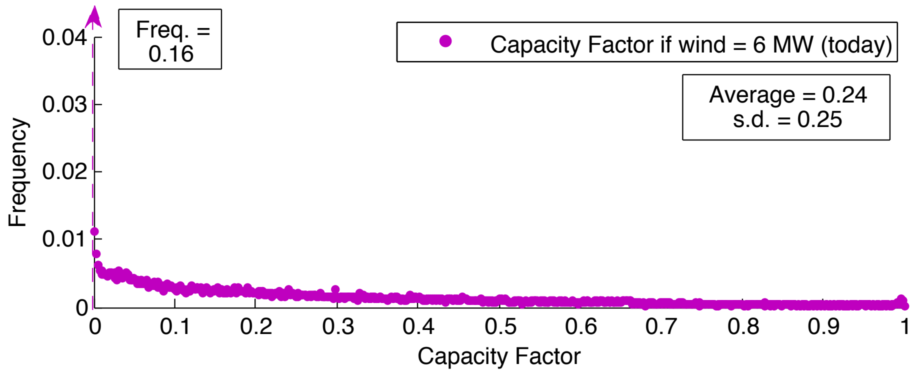


Figure 35 Wind Spill frequency distribution (above: today, below: 2030), if no grid reinforcements are made.



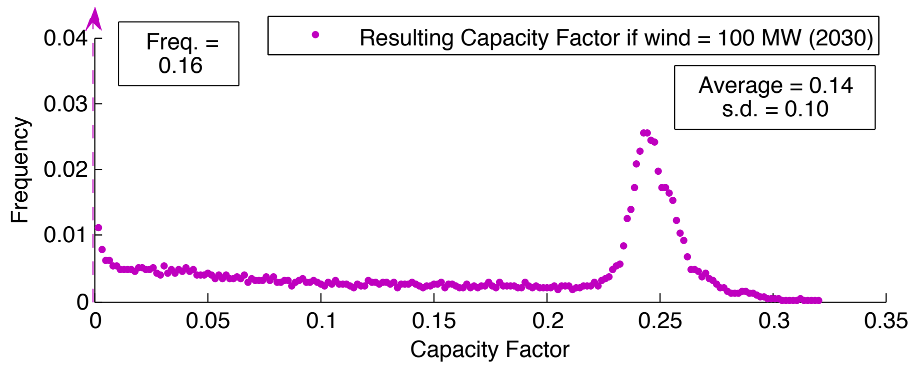


Figure 36 Resulting capacity factor due to wind spill (above: today, below: 2030), if no grid reinforcements are made.

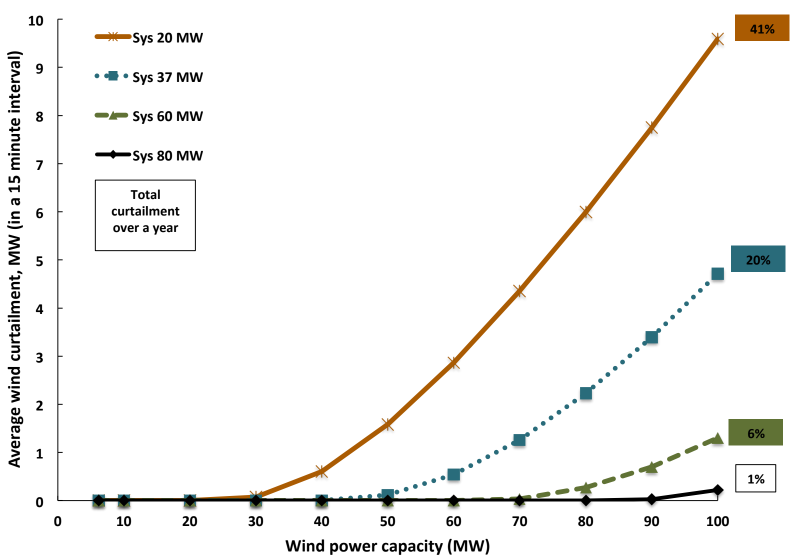


Figure 37. Wind power curtailment in region 1, if wind power capacity increases from 6 MW to 100 MW. Curves for capacities of the system (*Sys*) between 20 MW (today) and 80 MW.

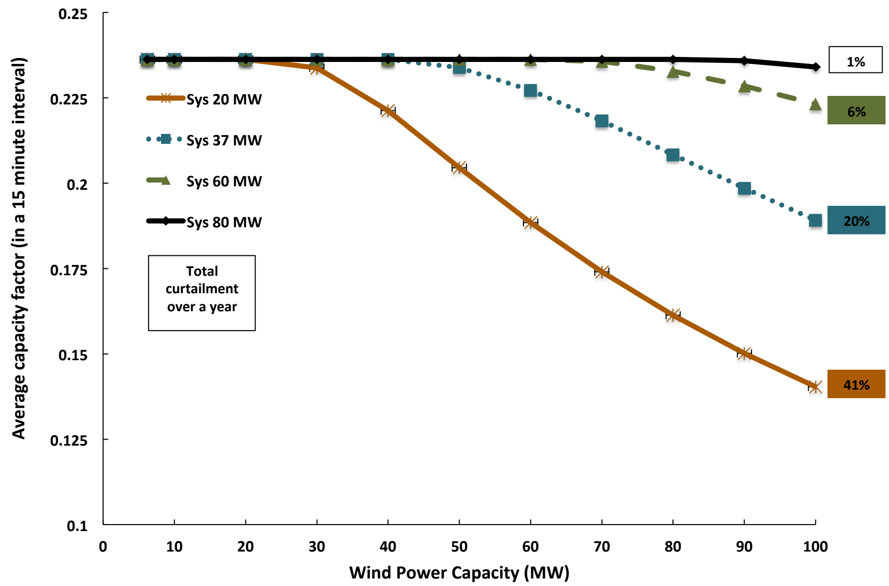


Figure 38 Wind capacity factor (MW) in region 1.
Local system's capacities of 20 MW (today) up to 80 MW.

5 Chapter 5: Final remarks and policy recommendations

Portugal has become a leader in wind power penetration by implementing and sustaining a feed-in tariff mechanism. The country now needs to decide how to maintain its position as a "green" electricity producer, while at the same time overcoming the challenges brought by an economic recession and electricity prices that are high compared to the rest of the European Union.

Policy-makers should consider updating Portugal's wind support policy since:

1. Wind feed-in tariffs in Portugal do not incorporate any financial risk or digression rate besides inflation, in contrast with the premiums or power purchase agreements offered by other countries. The consequence is that support is higher when spot market prices are low –a skewed system that is expected to continue until 2036.

2. Of those countries with a mature wind power sector, Portugal has the longest feed-in tariff period. As a technology matures, the costs generally decline as the industry learns how to manufacture and produce technologies that are more efficient and at lower production costs. This has indeed been the case for wind, and so the wind industry globally may not need the same level of incentives as before. Some power plants have yet to be been decommissioned, despite being in operation for more than 20 years. All wind parks that are currently in operation have received feed-in tariffs since initial grid connection, and they are expected to keep receiving these until December 2019 at least, and perhaps up to December 2036.

3. Wind producers do not bear any risk of power curtailment because, by law, all wind produced needs to be absorbed by the grid. This, in turn, requires a grid infrastructure at the transmission and distribution level that can accommodate wind production variability. At this stage of wind energy deployment, where wind power satisfies 24% of demand in Portugal, planning network

capacity for zero wind power curtailment is likely to result in in several location in lines with little occupancies, and it restricts access to existing connection lines, limiting the availability of sites for new wind parks. Our analysis for one site found that even for the most conservative estimates of system utilization in the regions analyzed, system capacity availability is at least 80% during four fifths of the year.

As a result of the analysis provided in the previous chapters, a few final remarks follow:

1. Estimates on the profitability of wind parks connected between 1992 and 2010 show that under the 2005 legislation (in which feed-in tariffs were granted for 15 years), all existing wind parks have positive NPVs when considering a 20-year lifetime. In fact, most of existing wind parks can stop receiving the feed-in tariff now (July 2014). Moreover, under the 2013 feed-in tariff reform that aims at decreasing the electricity system's deficit, total spending will increase and wind parks will have larger profits than under the 2005 legislation. The environmental and energy dependency benefits of the Portuguese wind sector could have been achieved with as much as 25% less spending. This suggest that alternative schemes for the support of renewables, that account for the fact that wind levelized costs have decreased over time as a results of learning, should be considered. Lowering the FIT would still enable wind producers to recover the cost of their investment.

3. For future wind parks connected to the distribution grid, wind investors will maximize their profits if the policy releases the guaranteed availability of grid resource at all times for wind producers, and allows for some wind power curtailment. In Chapter 4, we have assessed the implications of curtailment in one substation of Energias de Portugal, as it is one of the substations that is likely to receive major additions of wind power until 2020. We found that from the wind power investor's perspective, the maximum NPV is achieved with 1% wind

power curtailment. Wind curtailment can also offer the alternative to policy makers of limiting revenue of wind investors -if lowering the feed-in tariff is not politically feasible at this moment. For instance, allowing for wind power curtailment of as high as 20% in the substation studied can in fact reduce return to investment for new parks from about 40% to 14%.

Wind curtailment could serve as a mechanism to reduce exports to Spain if needed, in particular when wind generation is high. It could be wise to reduce exports at high wind penetration moments and when the market electricity price is lower than the wind feed-in tariff to avoid that Portuguese tariff payers subsidize Spanish electricity consumers. This yields savings in terms of avoided transmission and distribution grid capacity investments, and in terms of FIT payments. We did not estimate the benefits and costs of this approach compared to the pumped-hydro storage strategy that Portugal has employed, but subsequent work could compared these, especially since pumped-hydro storage will three fold in the next 15 years.

3. For rate payers, the electricity rate paid is increased to support the feed-in tariffs scheme. Residential electricity rates do not reflect the variations of the spot electricity market, and thus consumers are indifferent to wind resource changes. If electricity rates better reflect resource availability, demand response schemes could also be implemented. We did not evaluate the feasibility of such schemes, but subsequent work could relate to demand response mechanisms that better reflect Portugal's high renewable power resource.

This work will help Portuguese policy makers evaluate the design of the country's renewable policy, and promote more cost-effective measures to attain Portugal's 2020 wind power goals.

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