The Social Cost of Wind Power

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June 2008

Abstract

Wind powered generation (WPG) is the dominant renewable energy source for electricity production. The impossibility to stock electricity coupled with the intermittent nature of WPG limits its contribution to the adequacy of electrical systems. We investigate this issue from an economic rather than technical point of view and define the *social cost* of wind power as the difference between its actual cost and its *system value* i.e., the cost of replacing the produced energy, hour by hour, using more intensively the remaining thermal technologies. We further divide this social cost into *technological* and *adequacy* components. Whereas the former may become negligible once thermal technologies pay for carbon emissions, the latter is a lower bound on WPG structural weakness wrt. thermal technologies.

We contrast our theoretical proposal with the literature and then measure it empirically using hourly data from Denmark, Spain, Germany, Ireland and Portugal for load and WPG. Our empirical findings show that there is a grain of truth in both the pros and cons of wind power. Realized capacity factors are sensibly lower than predicted (even for islands and coastal areas) which turn into a large technological cost. Regarding adequacy, windier areas also sport a more adequate resource. All in all, WPG appears to bear a 20 to 25% premium over the cost of serving yearly load in a system. Geographic integration of market however allow for a significant reduction.

JEL codes : L51, H42, D61

Keywords : Electricity, Network Externalities, Industrial Organization, Renewables, Planning

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1 Introduction

As can be assessed from Table 1, our modern economies are energy voracious but problems are looming large. High fossil fuel prices have triggered a mild demand-side strategy of reducing consumption patterns by a better education and improving the energy efficiency of machines and building. However, the fear of climate change has lead most governments to choose an easier to sell supply-side strategy, the achievement of a significative share of renewables in their energy mix (through hefty subsidies).

Area	Energy	Electricity
US	248	36
OECD	149	22
EU25	115	xx
World	54	6.6
Ethiopia	12	0.1
food intake	2.8	

Table 1: Per capita daily consumption in kWh

The main idea behind this strategy is to meet electricity demand with clean technologies instead of polluting ones by taking advantage of the renewal of aging fleet of generators. Thanks to the subsidies provided by states like California, Denmark, Germany or Spain, wind powered generation (WPG) has been able to develop into a full-fledged industry. Over the last twenty years, this technology has benefited from economies of scale and experience. WPG has thus proven to be the most economical way to achieve the aforementioned environmental goal.[1] Although it remains an expensive source of electricity, two recent developments are helping WPG to become fully competitive by making fossil fuels relatively more expensive, namely the surge in oil and gas prices and the establishment of the compulsory carbon emissions trading system (ETS) in Europe.[2] Notwithstanding this transformation, the regulation of WPG is unlikely to change soon as it will continue to receive legal and financial support from public authorities.

Although the commodity we ultimately consume is electrical energy, measured in MWh, our time pattern of consumption, how many MW we demand at every instant, matters for generation cost. There is thus a meaningful distinction between power (instantaneous energy) and energy (long lasting power). Now, the social benefit of wind power is measured by tons of avoided carbon emissions, these in turn are proportional to electricity generation, the *energy* dimension. In other words, a wind turbine fights global warming ONLY when rotating because only then can it substitute a fossil fuel generation plant.[3] The distinction between MW (power) and MWh (energy)

[1]This objective remains however distant because the increase of generation from renewables over the last decades has failed to cover the demand increase so that virtually no contaminating sources have been substituted.

[2]This scheme aims at pricing the negative externality of fossil fuels, it includes oil, gas and coal but excludes uranium, the source of nuclear power.

[3]Awkwardly, the wind power industry and the environmental lobby put much emphasis on cumulated installed capacity (power). A possible explanation apart from the obvious regulatory capture argument is that the number of

is inconsequential for most fuels but not for wind and this relates to the issue of *load following*. Since it is nearly impossible, or for that matter extremely costly, to stock electricity, sudden demand variations whether scheduled, predicted or unpredicted must be accommodated instantaneously by the available generating stations. Because these variations are frequent and large, it is of the uttermost importance that a power plant be controllable i.e., able to increase or decrease output at will (or at least on short notice). Sadly, wind power (like tidal and solar power) does not possess this property because its intermittent output is driven by the forces of nature alone.[4] This failing quality is a source of social cost we shall estimate.

The standard externalities approach builds on the *social cost* = *private cost* + *external cost* formula. ExternE (2002)[5] reports a positive external cost for WPG but quite small when compared to that of fossil fuels based generation; we thus assume a zero external cost for WPG, so that its external benefit is simply the external cost of thermal technologies. Our main contention then is that the priority feed-in bestowed on WPG is a source of external cost for society. For that task, we proceed to make the following decomposition:

	WPG price	=	entry premium	+	private cost
where	private cost	=	system value	+	social cost
where	social cost	=	technology cost	+	adequacy cost

Since the government sets the price of WPG that is later billed to consumers, the difference with cost is an entry premium for developers whose role is to attract investment in the field. The entry premium being a transfer from consumers to WPG developers, it bears no inefficiency as far as wealth effect are absent. Upon computing the system value of WPG, we may define its social cost as the difference with private cost. We further divide the social cost into two orthogonal categories. The technology cost is sensitive to the price of fossil fuels and long-term wind intensity whereas the adequacy cost is strictly related to the temporal congruence of demand and wind speed.

Let us now preview the calculation of WPG's system value. For given system and year, we compute the cost of meeting electricity demand with and without wind power. To enable comparisons, we do not use spot prices but an efficient fuel mix with standardized technology costs for thermal and wind options. The total cost difference, if positive, is the social cost of wind power for that area. On the one hand, doing without WPG saves on investment (the actual cost of developers) but on the other hand, thermal technologies must be scaled up to compensate for the missing energy. We are thus lead to compute the cost of replacing each MWh of wind electricity produced during the year by a thermal MWh. This calculation is not simple because a MWh of wind power produced at 6pm on a week day when electricity demand peaks is much more valuable, thus costly to replace, than a MWh produced in the middle of the night when there is plenty of cheap generation available. We propose a method to compute this *system value* of wind power.

windmills is a figure that speaks to the public whose support is though after.

[4] Although night storage in batteries for next day delivery is a technical reality, it is still estimated to cost 4.5M$/MW i.e., four times the cost of wind power. cf. also McDowall (2007) or Li and Joos (2007).

[5] This project funded by the European Commission has estimated the external cost of most technologies for electricity production. It looks at impacts on the environment (biodiversity, noise, visual intrusion), global warming, health and accidents.

Our work is related to the literature assessing the cost of integrating a large amount of wind power generation within an electrical system. This includes Gross et al. (2006) (cf. extensive bibliography in annex 3), Giebel (2005), RAE (2004), UIC (2007) or Tarjanne and Luostarinen (2002). There has been a controversy regarding how much back up is needed when adding wind turbines to maintain security of supply at system level. It is our contention that this issue cannot be meaningfully disentangled by theory or simulation. To get a clearer picture, one needs to match hourly demand data and wind power production. We collect such a data for recent years in various European countries.

Section 2 of this article introduces the background concepts necessary to get a clear picture of the problem at hand. Section 3 deals with the cost of meeting electricity demand by a variety of technologies, the optimal combination of technologies and the efficient able to serve yearly demand at minimum cost. Section 4 then presents the concepts offered in the literature to compute the capacity credit of WPG together with our proposal. Section 5 then present our estimations for European countries whose load and WPG output are made publicly available. We also offer some extension for the value of marginal additions of WPG and for geographical aggregation. Section 6 concludes.

2 Wind and Adequacy

2.1 Reliability

From a technical point of view, the *power vs. energy* dichotomy refers to *reliability* vs. *adequacy* (short vs. long term). Appendix A develops these notions. We shall focus exclusively on the relation of WPG to adequacy. The complementary assessment of the impact of WPG on reliability has been undertaken by TSOs whose primary mission is to guarantee reliability. They conclude that the introduction of large amounts of wind power has not created serious reliability problems and that the necessary system reinforcements have been achieved at a reasonable cost. We shall thus implicitly assume that demand and weather forecasts are utterly precise in the sense that tomorrow's curves for load and WPG output are known in advance so that generation resources needed to cover the residual demand can be contracted in spot markets from standard low cost technologies i.e., no costly reserves (black-start, spinning) are used.

2.2 Capacity Credit

Opponents to wind power, typically fossil fuel generators and TSOs whose profit margins might be threatened by the massive inclusion of WPG, use the occurrence of "zero wind" periods to argue that each MW of wind power needs one MW of back-up (switchable thermal power); this would obviously make WPG extremely costly. Supporters of renewables respond with numerous empirical studies that the geographical dispersion of wind turbines across the land smooth out the temporal distribution of WPG with two valuable consequences: the probability of a "zero wind" period is almost nil and prediction models become more accurate which enables greater market participation for WPG operators and easier scheduling for TSOs.[6]

There is a grain of truth in both views which calls for a synthetic index in order to weight them. The impact of wind intermittence on a system has been traditionally assessed with the *capacity credit*, a percentile measure of the conventional thermal power that the addition of wind power might enable to retire while maintaining both system reliability and (yearly) electric output. It should be noted that in this definition, the emphasis is on reliability, not adequacy, probably because the concept was created by TSOs whose immediate responsibility is reliability.

The opposing views alluded to before translate into the use of capacity credit calculations. The pro-wind lobby contents itself with claiming that wind has a positive capacity credit, implicitly treating a small value below 10% as equally attractive as a large value, say 40% (e.g., offshore wind farm). For instance, Giebel (2005)'s abstract states "*capacity credit ... drops to a value near the minimum wind power generation for larger penetrations*" but this author refuses to acknowledge that the value he is implicitly referring to is actually zero. On the other side of the fence, Eirgrid (2004) (Irish TSO) reports the same finding more bluntly: *When increasing amounts of wind are added to the system, reliability improves. As a result, amounts of conventional thermal plant may be removed to restore the reliability to the criterion level. This quantity of conventional plant is termed the "capacity credit" that is attributable to wind. However, it is an unfortunate fact that the contribution to reliability of additional amounts of wind decreases progressively and tends towards zero. Consequently, the incremental capacity credit of increasing WPG tends to zero.*

More to the point, the capacity credit of WPG is computed as a function of WPG penetration in percentage of the installed power which is empirically decreasing. This knowledge is useful for adequacy management in the old regulatory compact where a central authority (e.g., energy agency) decides on the rate of decommissioning and construction of new power stations to control the so-called capacity margin, the wedge between installed capacity and foreseeable yearly peak (of load). This way

Fewer authors have gone further in trying to estimate the adequacy cost of wind power. Dale et al. (2004) claim that to compute the cost of intermittence of WPG, all that is required is the determination of the least cost, baseload, *energy equivalent comparator*, i.e. the thermal plant that would supply the same energy in the absence of intermittent generation. The choice of baseload for this comparator is motivated by the fact that if WPG participated in power markets on equal foot with thermal technologies, it would be baseload since its marginal cost is zero. The proposed social cost of WPG would thus be the product of the capacity credit of WPG by the cost of the energy equivalent comparator.

This is an incorrect approach for it assumes that every MWh of wind power generation substitutes a MWh from a cheap baseload plant which is not the case at all. We thus have to consider the system's cost curve which is the lower envelope of the different cost functions corresponding to the available technologies. We are then able to compute total and average cost of serving yearly load and residual load. We then compute the cost for the current park of thermal stations to increase

[6] This smoothing also contributes to reduce very short term variability (below one minute) and to improve reliability. recall indeed that the output of a single turbine displays several harmonics i.e., varies within seconds, minutes, hours and days.

generation to serve D instead of Z. By construction of Z, the total energy so generated is exactly the yearly output of wind turbines present in the system. Due to the intermittence of wind, the residual load curve Z is not a downward translation of D (that would be the case of biomass which can be operated as baseload), Z tends to be a vertically stretched i.e., shows relatively less baseload and more peaks. Hence, Z has a greater average cost than D. Total cost TC_Z is obviously lesser than TC_D since less energy is served. Our estimate of system value is thus $\frac{TC_D - TC_Z}{G_W}$. The so-called technology cost is introduced to provide a link with the intermittence cost that previous studies have computed; it is the difference between true cost and the mean market price of electricity $\frac{TC_Z}{G_Z}$.

However, the main problem with the capacity credit is not so much with its computation but with its use. A pure economist would object to this very concept that the quantity we are looking for is irrelevant because the market will price it anyway. Whatever the amount of backup power needed, market forces will guarantee that in the mid term the right amount of controllable generation is active. If, for sometime after the introduction of massive amounts of WPG, prices swing greatly because peakers are missing when WPG output is low, then entry of peakers will occur. If, on the contrary, price peaks tend to disappear because WPG is highly correlated with demand peaks then peakers will not earn their cost of capital and will exit (or obsolete plants won't be replaced). Thus, WPG would displace generation that is more expansive on a yearly basis.

This argument is correct for a fully liberalized generation market. Actual markets however differ from this ideal in two dimensions. Firstly, spot markets use mandatory price ceilings that limit the rents for peakers and have depressed entry. Secondly, wind power is and will remain subsidized. Our analysis must then be framed within this particular context where central authorities decide on the system margin and take direct steps to implement it. In that light, our result inform regulators about the cost of introducing massive amounts of WPG.

3 Cost of Electric Generation

We start with a detail account of WPG before giving the theoretical treatment covering both thermal and renewables technologies.

3.1 Wind Power

We substantiate here the claims made in the introduction regarding WPG economics. Forty years ago, tidal and solar energy were claimed to be as promising as WPG but have utterly failed to make a significant contribution. There is no doubt that the massive subsidies to WPG from Denmark, California and Germany in the 80s (and Spain in the 90s) have turned it into a full-fledged industry.[7]

Economies of scale Taller wind turbines not only are more powerful but also capture speedier winds so that their output increases more than linearly with respect to size; connections costs are

[7] IEA's Global Renewable Energy Policies and Measures Database shows that Denmark started funding research on renewables in the 1970s. During the 1980s, Denmark and Germany introduced regulations and support schemes for WPG. Most remaining EU members followed during the 1990s.

also smaller for a group of few large turbines as compared to a group made of many small units. However, Kaltschmitt et al. (2007) (cf. Table 7.3 p369), looking at the levelized energy cost, report a mild 10% saving from using 5MW turbines instead of 1MW (both current state of the art).

Economies of experience Wiser and Bolinger (2007) study US data over the 1982-2006 period which indicate a decrease from 4M$/MW down to a minimum of 1.3M$/MW in 2004 ($\approx -2.4\%$/year) and since then a slight increase up to 1.5M$/MW in 2006 (cf. fig. 18). According to English study SDC (2005), the price of wind turbines fell from 1.4M€/MW down to .8M€/MW ($\approx -3.7\%$/year) over the 1990-2004 period. German data indicate a fall from 1.5M€/MW down to 1.05M€/MW ($\approx -2.3\%$/year). Notice finally that turbines account for 3/4 of the price of a wind farm.

Decreasing Returns to Geographical Scale The best sites are found on the coastal areas of Europe. Even though these are sparsely populated in Northern Europe, saturation might become a problem in the future. The issue is more serious in the Mediterranean as it is densely populated and/or devoted to tourism so that local business or even resident are opposed to wind turbine sitting. Commenting on the development of wind farms in France during 2005 and 2006, RTE (2007) reports that local opposition has proved a particular obstacle to projects in the Mediterranean and coastal areas, leading to more inland installations in northern and eastern France where wind conditions are relatively worse. There is here an avenue for future research but detailed project data is needed to find out if this potential problem already bites. According to Wiser and Bolinger (2007), capacity factor in the US has increased over the last decade thanks to taller turbines, improved siting and technological advancements. Thus the exhaustion of quality sites does not seem to be a problem in that very large country.

Current Cost SDC (2005) aggregating data from Denmark and IEA, reports an average capital cost of 1M€/MW (resp. 1.6M€/MW) and O&M cost of 2.5% (resp. 3.5%) for onshore (resp. offshore) WPG (conversion rate 0.7£/€). Kaltschmitt et al. (2007) indicate 1 M€/MW (resp. 2M€/MW) for German onshore (resp. offshore) and considerable O&M in the range 5–8% of the investment for onshore (even higher share for offshore). More recently, Ernst and Young (2007) find 1.6M€/MW for current development in the UK, rising w.r.t. previous years due to a capital cost increase and delays from manufacturers since world demand for wind turbines is exploding. We settle for an average value of 1.1M€/MW regarding capital cost which is found in Eirgrid (2004) or reported by the portuguese TSO for project benefitting from public subsidies. Regarding O&M, we disregarding the finding by Wiser and Bolinger (2007) according to which O&M costs quadruple over the lifetime of a turbine and adopt a value of 1.5% of the capital cost.

Current Subsidies The current subsidy schemes in place in Europe either use price or quantity support. The UK and Italy require distributors to either include a minimum share of renewables in their electricity purchases or to buy-out their obligation. The tightness of current quotas is sufficient to induce high prices and this should attract more investment; yet most firms buy-out their obligation instead of reducing their emissions (by either filtering smokes or adding wind power to their generation park). This unexpected outcome is probably the consequence of a perceived high market risk associated with entering the renewables electricity market. The other support mode pioneered by Denmark, Germany and Spain has proved much more effective and is currently more popular. The scheme uses an initial feed-in tariff around 80€/MWh together with a phasing down towards 65€/MWh after five years. Spain is even more attractive as it gives the option to earn 40€/MWh on top of the Iberian pool price (currently above the 40€/MWh mark). At current feed-in tariffs, our findings show that the wind power market remains attractive for entry.

Future Developments WPG has proven to be the most economical technology to increase the share of renewables in the energy mix. The objective remains however distant because the increase of generation from renewables over the last decade has failed to cover the demand increase so that virtually no contaminating sources have been substituted.

Although it remains an expensive source of electricity, two recent developments are helping WPG to become fully competitive by making fossil fuels relatively more expensive, namely the surge in oil and gas prices and the establishment of the compulsory carbon emissions trading system (ETS) in Europe.[8]

3.2 Levelized Cost

In this section, we present the general methodology to assess the levelized cost of electric generation which enables comparison among technologies; we draw on a variety of studies to pick representative estimates.

Since we shall deal with fixed and variable cost, the duration of the period under study is an important ingredient. We use the year for expositional simplicity i.e., $T = 8760$ hours but any other choice would be acceptable (especially longer periods to smooth out yearly variations in wind speeds). Given the yearly interest rate r defined by the cost of capital and the amortization period τ (in years), the annuity factor is $\frac{r}{1-(1+r)^{-\tau}}$. Letting F be the capital cost of a plant with standard capacity q (in MW) and η the operation and maintenance (O&M) yearly fixed cost in percentage of the initial investment, the yearly fixed cost per MW is

$$g = \left(\frac{r}{1-(1+r)^{-\tau}} + \eta\right)\frac{F}{q} \tag{1}$$

At the outset, technology $i = 1,..,n$ is characterized by the pair (c_i, f_i) of energy and power cost where

- c_i is the marginal cost (€/MWh) summing energy cost to variable O&M costs
- $f_i \equiv \frac{g_i}{a_i}$ is the fixed cost (k€/MW) or cost of (guaranteed) *power* with
- g_i being the (name plate) fixed cost (k€/MW) computed in (1)

[8]This scheme aims at pricing the negative externality of fossil fuels, it includes oil, gas and coal but excludes uranium, the source of nuclear power.

- a_i being the availability factor: the probability that a plant using this technology is available for generation. It accounts for scheduled maintenance and unscheduled failures.[9]

Against usual convention, we relabel technologies so that $c_1 > c_2 > ... > c_n$ i.e., #1 is the peaker whereas $\#n$ is the baseload. We then introduce a virtual technology. Two choices are available. The first, used by pre-deregulation integrated utilities, is the curtailment with power cost $g_0 \equiv 0$ and energy cost $c_0 \simeq 5000$€/MWh, the value of loss load (VOLL) i.e., the average that consumers would agree to pay in order to maintain service (and avoid curtailment). Nowadays, with the development of demand side response (DSM), some clients agree to get curtailed on short notice for a brief period (a few hours) with a maximum nomber of yearly occurrences.[10] Their compensation is a fixed payment g_0 for agreeing to participate and a variable payment c_0€/MWh each time the mechanism is activated. It is probably feasible to negotiate $g_0 \simeq 5$ and $c_0 \simeq 2000$€/MWh.

Numerical Estimates For thermal technologies, we use the estimates reported by RAE (2004) and Ernst and Young (2007) and a 7.5% (real) interest rate except for nuclear where we add a 2.5% risk premium. Table 2 displays all the cost parameters and the resulting relevant fixed and marginal cost for thermal technologies.[11]

Technology	Thermal					Wind	
Item (unit)	nuke	coal	gas	oil	DSM	land	sea
Investment (k€/MW)	2000	1250	600	500	na	1100	1400
Int. rate (%)	10	7.5	7.5	7.5	na	7.5	7.5
Amortization (years)	40	30	25	20	na	20	20
Annuity (%)	10.2	8.5	9.0	9.8	na	9.8	9.8
K cost (k€/MW/year)	194	106	54	49	na	108	137
O&M (% invest.)	1.5	2	2	2	na	1.5	2
Availability (%)	90	90	90	95	100	95	95
F. cost (k€/MW/year)	249	145	73	62	5	131	174
Marg. cost (€/MWh)	7	20	35	45	2000	0	0

Table 2: Cost of technologies

[9] For WPG, Kaltschmitt et al. (2007) reports an average value of 98%. This study also notes that the shadowing phenomena reduces the effective output of a park at 92% (on average) of its nameplate capacity, which is the maximum achievable when the turbines are optimally spaced, thereby occupying more land than is economical. All in all, the guaranteed power of WPG is only 90% of the nameplate capacity but since the generation data does not distinguish between a failure, a maintenance, shadowing or the lack of wind, there is no loss of generality in adopting a 100% availability factor instead of scaling down installed capacity and scaling up the capital cost.

[10] In Spain, for instance, maximum curtailment durations of 12, 6, 3 hours and 45 minutes are to be notified 16, 6, 1 hour and 5 minutes ahead.

[11] Using a conversion rate of 1.4US$/€, Borenstein (2008)'s estimates, in k€/MW and €/MWh are $(150, 18)$ for coal (baseload), $(66, 36)$ for CCGT and $(51, 54)$ for combustion turbine (peaker) which are nearby our choices.

3.3 Thermal Optimum

We restrict our attention to switchable (controllable) technologies, including DSM, participating in the continuous market for power. We leave aside WPG as it works under a feed-in tariff with priority dispatching.

The total cost of running one MW of technology $\#i$ for t hours during a year is $TC_i(t) = f_i + c_i t$ whereas its average cost is $AC_i(t) = \frac{f_i}{t} + c_i$. We define the efficient technology curve as $TC(t) \equiv \min_{i\leq n}\{TC_i(t)\}$; it represent the least cost of generating during exactly t hours per year. The efficient average cost is $AC(t) = \frac{CT(t)}{t}$. Whenever the curve of a particular technology is entirely above TC, it means the corresponding technology should not enter the generation mix.[12] By relabeling the remaining ones, we can define for $i \leq n$, the technology characteristic as the ratio of incremental power cost over decremental energy cost $\rho_i \equiv \frac{f_i - f_{i-1}}{T(c_{i-1}-c_i)}$ and, by construction, it is true that $\rho_1 < \rho_2 < ... < \rho_n$. Using the estimates from Table 2, we compute levelized cost for a variety of duration; they are reported in Table 3 together with on-shore and off-shore WPG for their relevant range of duration.[13] Figure 1 displays the average cost curve (clipped at 200 on the vertical axis to avoid flattening) together with the cut-off values ρ_i.

Duration	10	100	500	1000	2000	3000	4000	5000	6000	7000	8000	8760
nuke	+10k	2499	505	256	132	90	69	57	49	43	38	35
coal	+10k	1474	311	165	93	68	56	49	44	41	38	37
gas	7349	766	181	108	72	59	53	50	47	45	44	43
oil	6260	667	169	107	76	66	61	57	55	54	53	52
DSM	2500	2050	2010	2005	2003	2002	2001	2001	2001	2001	2001	2001
marginal	DSM	oil	oil	oil	gas	gas	gas	coal	coal	coal	nuke	nuke
on shore				131	65	43.6						
off shore				174	87	58	44					
Cap. factor				11%	23%	34.2%	46%					

Table 3: Levelized Average Cost by Duration and Technology

3.4 Efficient Technology mix

Aggregate demand is random and drawn at each hour from the same distribution.[14] The probability that demand exceeds Q is denoted $H(Q)$, it is also the cumulative frequency of hours where this event takes place. The optimum mix of technologies to serve this demand is the one minimizing the cost of serving it. Let $(q_i)_{i\leq n}$ denote the park of generation and $Q_i \equiv \sum_{j=i}^{n} q_j$ the maximum output of the cheapest i technologies. By switching one firm MW from baseload to peaker i.e.,

[12] Some are known to be present because generation markets are not fully competitive and therefore remunerate generation above TC.

[13] The numerical estimates are tweaked so that the all thermal technologies are conditionally efficient for some duration.

[14] We treat it as being completely inelastic. Price elasticity will be introduced in a future version of this paper.

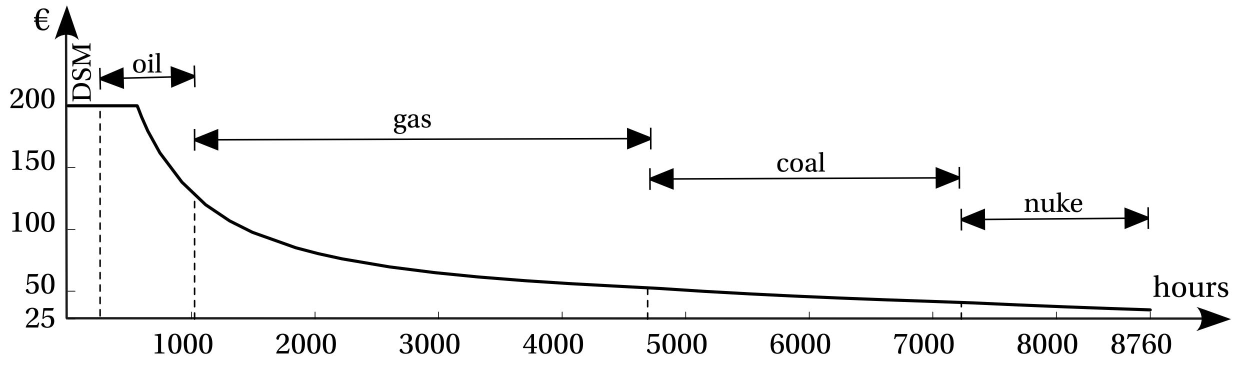

Figure 1: Efficient Average Cost Curve

from technology #i to #$i-1$, we save $f_i - f_{i-1}$ on capital cost but we spend an additional $c_{i-1} - c_i$ for every MWh that will be called for generation. The MW under consideration is called to produce each time the demand is greater than Q_i, thus the yearly number of hours of generation is $T \times H(Q_i)$. The installed baseload capacity q_i is optimal if there is no incentive to increase or decrease it i.e.,

$$f_i - f_{i-1} = (c_{i-1} - c_i) T \times H(Q_i) \Leftrightarrow \rho_i = H(Q_i)$$

Since $Q_n = q_n$, the baseload capacity ought to be $q_n = H^{-1}(\rho_n)$ i.e., the $\rho_n T$ largest hourly demand of the year. Recursively, $q_i = H^{-1}(\rho_i) - Q_{i+1}$ for all $i < n$. Notice that since $\rho_1 > 0$, Q_1 falls short of the maximum yearly demand meaning that curtailment or DSM (technology #0) is bound to occurs for $\rho_1 T$ hours each year. Increasing the VOLL to infinity amounts to nullify ρ_1 and eliminate curtailment. This corresponds basically to the obligation imposed until recently upon TSOs by governments. This is why the capacity margin, which the difference between installed capacity and foreseen peak load, is so large (often more than 20%).

4 Estimation

Given a a random variable, we denote $X = (X_t)_{t=1}^T$ the series of realizations at every hour during one year i.e., $T = 8760$ (8784 in a leap year). The mean is denoted $\mu_X \equiv \frac{1}{T}\sum_{t=1}^T X_t$ while the variance is $\sigma_X^2 = \frac{1}{T}\sum_{t=1}^T (X_t - \mu_X)^2$. In electricity, we use the decreasing ordered sample $\hat{X} \equiv \left(X_{(t)}\right)_{t=1}^T$ with minimum $X_{(T)}$ and maximum $X_{(1)}$.

The data to be analyzed covers a variety of system areas over recent years, it consists of the hourly demand (load) D and wind power output W out of which we construct the residual demand $Z \equiv D - W$. In the case of load, $D_{(T)}$ and $D_{(1)}$ are respectively called the base and the peak loads.

4.1 Temporal Variability

The volatility of a random variable $X \in \{D, W, Z\}$ is traditionally measured by the variance and made comparable among variables by using the coefficient of variation $\frac{\sigma_X}{\mu_X}$. This is a very poor statistic in our context since it completely ignores the time-series nature of the data at hand. Consider the example displayed on Figure 2. If, for instance, demand is constant at 10MW during the night and then jumps to 50MW during the day, then the daily mean is 30MW, the daily standard deviation is 20MW so that the daily coefficient of variation is 67%. However, demand has been pretty stable with just one (large) change during the period. The plain curve which describes a load alternating between 20 and 40MW every other hour has a lesser coefficient of variation but is intuitively more variable.

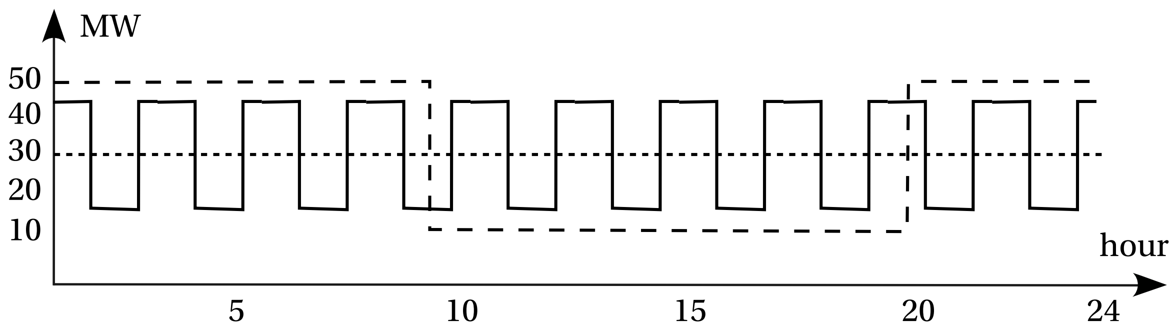

Figure 2: Examples of daily demand curve

A statistic that reflects the temporal stability in this example but also captures the many ups and downs of the variables under study is the "arc length" $\sum_{t=2}^{T}\sqrt{1+(X_t-X_{t-1})^2}$ of the polygonal path displayed by the values X.[15] To enable comparisons, we use instead the mean rate of hourly absolute percentage change[16]

$$\delta_X \equiv \frac{1}{T-1}\sum_{t=2}^{T}\left|\frac{X_t-X_{t-1}}{X_{t-1}}\right| \tag{2}$$

A related issue that has been given some importance in the literature is the "zero wind" event. A "zero wind" event is a period of several hours without wind over a given area. Although every location suffers chills every year, it is quite rare that such a contingency affects the entire system. To measure this phenomenon, we define a "zero wind" event as more than 4 consecutive hours where the wind output is less than one percent of the recorded yearly maximum (itself lesser than the installed capacity).

4.2 Temporal Wind Availability

The *capacity factor* (on an annual basis) is the ratio of the mean delivered power over the nameplate capacity (both in MW); alternatively, it is the ratio of actual yearly production over the theoretical maximum that would be achieved if perfect wind conditions lasted all year long (both in MWh). This indicator measures the average share of windy hours during a day or equivalently, the probability that wind is available at any moment.[17] A capacity factor can be computed for a variety of geographical areas from a single windmill to a complete system (and also for a variety of time

[15] Imagine yourself crossing the Pyrenees from the Atlantic till the Mediterranean walking over the mountain crest. The distance you'll walk is the arc length of the variable X = "altitude at the crest".

[16] It would be similar to study the difference variable $Y_t = X_t - X_{t-1}$ and compute its coefficient of variation.

[17] In fact and like any other technology, wind turbines can suffer faults (forced outage) or be halted for maintenance (planned outage). The most reliable technology is CCGT and has a capacity factor that can reach 95%.

spans). The yearly measure based on the capacity at year's end published by TSO's is inappropriately low because new capacity is being installed during the year in most countries. In the absence of data regarding the installed wind capacity K_t at each point in time, we use a constant, the mid-year average $E[K] = \frac{K_0+K_T}{2}$ where K_0 is the installed capacity at the end of the previous year and K_T is the installed capacity at the end of the current year. Our estimate of the capacity factor is thus

$$\rho \equiv \frac{1}{T}\sum_{t=1}^{T}\frac{W_t}{E[K]} \tag{3}$$

The product ρT is called the "equivalent annual hours" of duration.

4.3 Adequacy Index

The measure we introduced in the example, $\phi \equiv \frac{\hat{D}-\hat{Z}}{E[K]}$, to capture the idea of capacity credit involves the realization of several random variables, namely the maximum $X_{(1)}$ of a series of yearly realizations for $X = D, Z$. Extreme value theory, a branch of statistics, studies the distribution of $X_{(1)}$ under the assumption that the series $(X_t)_{t\le T}$ are drawn from independent and identically distributed (i.i.d.) random variables. It can be shown that the law of $X_{(1)}$ converges to $\bar{H}(x) = e^{-e^{\frac{\alpha-x}{\beta}}}$ whose mean is $\hat{\mu}_X \equiv \alpha + \gamma\beta$ where $\gamma \simeq .57$ is the Euler constant.

To estimate the parameters α and β (and the mean $\hat{\mu}_X$), we use the peak over-threshold heuristic method by selecting a small percentage ξ of the largest realizations of $X = D, Z$ and fit the empirical CDF to $\bar{H}$ using least squares. We thus compute the adequacy index as

$$\phi \equiv \frac{\hat{\mu}_D - \hat{\mu}_Z}{E[K]} \tag{4}$$

4.4 Capacity Credit

This index originally advocated by Milligan (1996) and Milligan (2000) has been adopted by many US utilities and TSOs for its ease of implementation. One selects a small percentage ξ of the ordered load sample $\hat{D} = \left(D_{(t)}\right)_{t=1}^{T}$ and computes the average wind capacity factor over these hours of peak demand. The capacity credit is thus

$$\lambda \equiv \frac{1}{E[K]}\sum_{t\le T} W_t \mathbb{1}_{D_{(t)}\ge D_{(\xi T)}} \tag{5}$$

By construction, this measure is invariant to the scale of the wind power series; thus, it does not inform us on whether a large addition of wind power is a stress or a relief for the system operator. The capacity credit is also mostly invariant to the shape of the load curve as it treats equally all selected hours of system stress i.e., fails to distinguish recurring stress (e.g., every week day at 20h) from exceptionally intense stress (e.g., cold spell on a winter week day).

An inspiration for the capacity credit index is Garver (1966) whose method is based on the development of an exponential risk approximation function. Risk at the peak hour being maximum, it is normalized at unity while risk for another moment is $e^{-\frac{\hat{D}-D_t}{m}}$ which rapidly decreases towards zero as demand moves away from the peak. One solves in the parameter m the following equation

$\sum_{t\leq T} e^{-\frac{\hat{D}-D_t}{m}} = M$ where M is the system risk that ought to be computed using a full fledged reliability model. The wind contribution is then computed as the average capacity factor weighted by the risk function i.e., $\lambda = \frac{1}{ME[K]} \sum_{t\leq T} W_t e^{-\frac{\hat{D}-D_t}{m}}$. If maximum wind output is strongly correlated with demand, then λ is close to unity. In the absence of reliability models for the system considered in this study, we use a numerical value between 2 and 10 to perform comparisons with Milligan's index; we find insignificant differences which are therefore not reported.

As will become clear, our approach bear similarity with Garver (1966)'s since we basically substitute his technologically based risk measure by the levelized cost. This is a natural procedure since his interest was in assessing reliability whereas ours is to assess adequacy.

4.5 Adequacy Cost

The load curve of a random variable X is the plot of the ordered sample $\hat{X} = \left(X_{(t)}\right)_{t\leq T}$. The upper panel of Figure 3 displays conjointly the load curves of D and Z; the middle panel displays the resulting difference curve $\tilde{W} \equiv \hat{D} - \hat{Z}$, we choose to name the *anachronous wind yield*. Indeed, $\tilde{W}_t$ is the difference between the t^{th} strongest load of the year and the t^{th} strongest residual load of the year which occurred at different moments of the year so that all time reference is lost when constructing $\tilde{W}$. Notice however that $\tilde{W}$ and $\hat{W}$ have the same mean. Indeed, by construction of Z, $\mu_Z = \mu_D - \mu_W$ and since a load curve is a reordering of original realizations, we also have $\mu_{\hat{D}} = \mu_D$, $\mu_{\hat{Z}} = \mu_Z$, hence $\mu_{\tilde{W}} = \mu_W$.

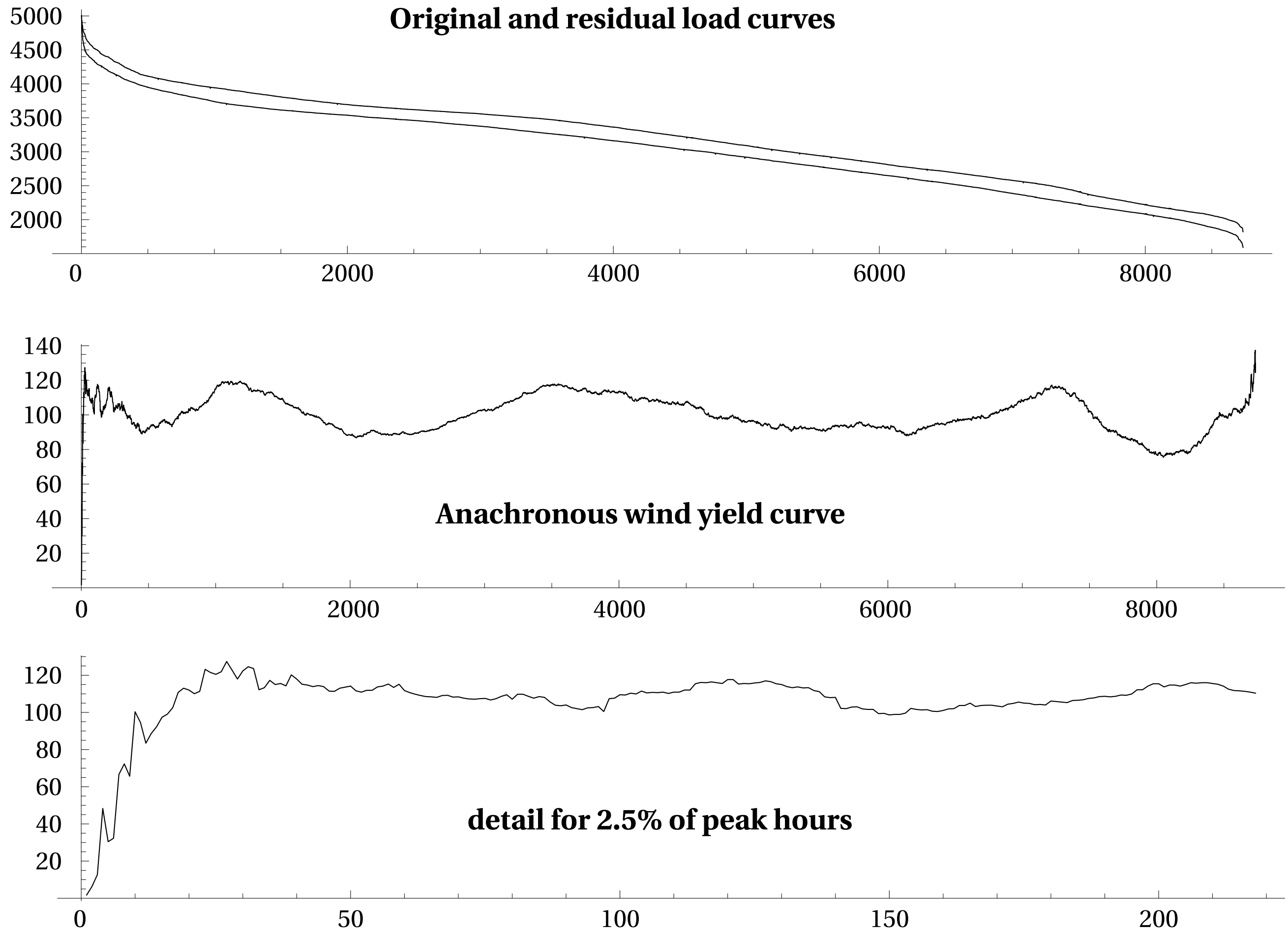

Figure 3: Wind contribution to adequacy: Ireland 2006

In practical terms, the range of $\tilde{W}$ is compressed with respect to the original wind power output $\hat{W}$. The data for the middle panel of Figure 3 is normalized so that the mean of $\tilde{W}$ is 100. Lastly, the bottom panel displays a detail of the previous curve for the 2.5% top hours of system stress (220 hours). Whereas Figure 3 displays results for Ireland, Figure 4 shows those for Denmark, both for the year 2006. The striking difference between the two systems is that Irish wind contributes much (index larger than the mean) when the system is under stress (hours of peak demand) which is when additional MW are most valuable. On the contrary, Danish wind makes a heavy contribution in slack hours i.e, in the middle of the night when demand is at the baseload and a very weak one at peak hours (index below half of its mean).

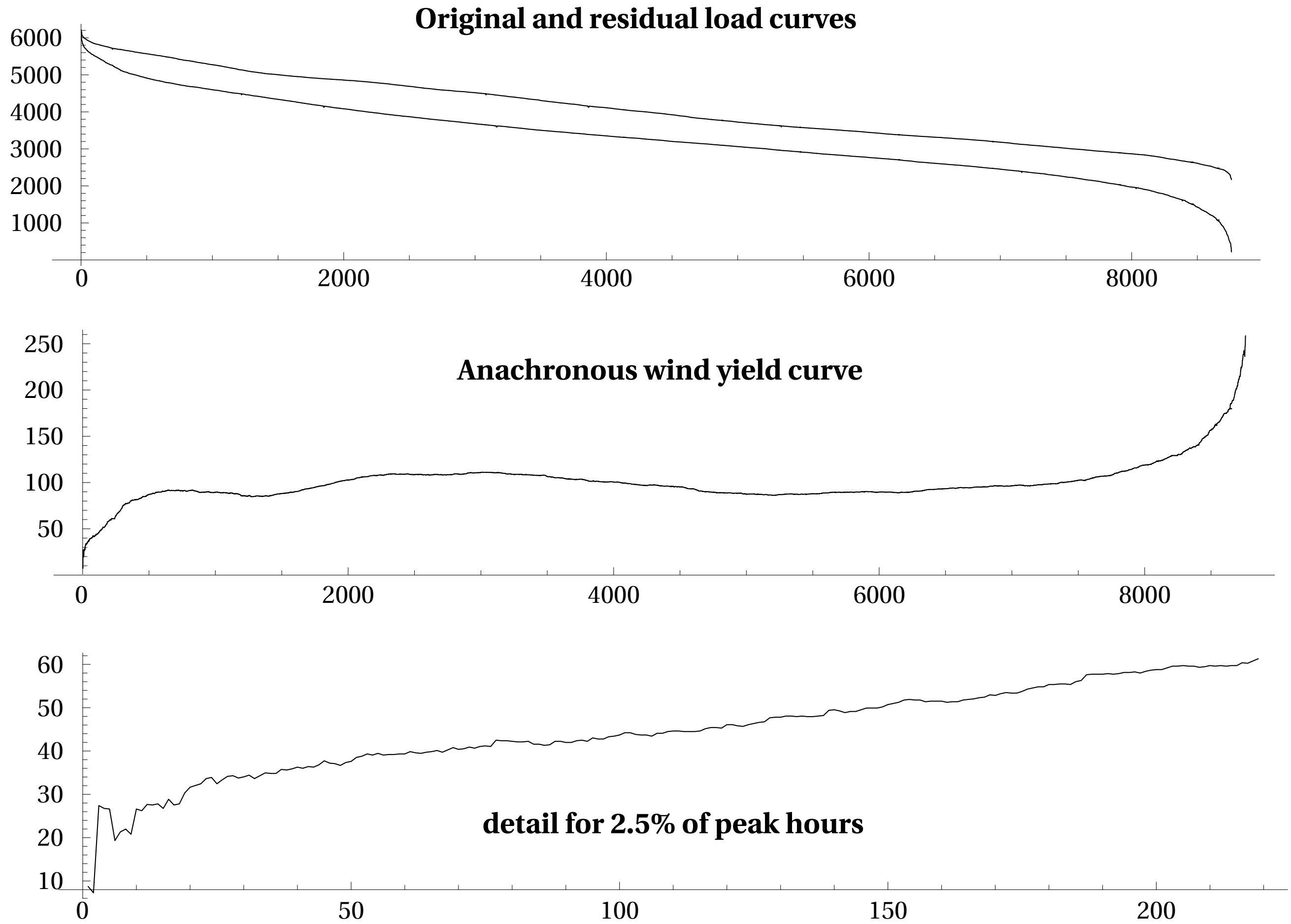

Figure 4: Wind contribution to adequacy: Denmark 2006

Given the efficient cost curve $C(t)$ and letting $X_{(T+1)} = 0$, the total cost of a load curve X is

$$C_X \equiv \sum_{t \leq T} (X_{(t)} - X_{(t+1)}) C(t) \tag{6}$$

while its total energy is $T\mu_X$. The cost of adequacy is defined in two steps; we first define the system value of wind energy[18] as $C_D - C_Z = C_{\tilde{W}}$, by construction of the anachronous wind yield curve. The idea here is to assume first that wind is present so that the demand for thermal stations is Z whose cost is thus C_Z. We then consider to a hypothetical world without wind power, the demand curve being D, its cost is thus C_D. We compute both costs, for an optimally sized park of thermal stations.[19] The difference $C_D - C_Z$ is thus the cost saving brought about by the wind load curve W taking into account how much is released hour by hour. Dividing by the wind energy output $T\mu_W$, we obtain a levelized MWh system value $\beta \equiv \frac{C_D - C_Z}{T\mu_W}$, a replacement value of WPG.

The private yearly cost of a 1MW wind turbine being denoted C_W for notational convenience, the levelized MWh wind cost is $c_W = \frac{C_W}{T\mu_W}$. Since the average cost of energy for thermal producers in the absence of wind is $\gamma \equiv \frac{C_Z}{T\mu_Z}$, we interpret the difference $\delta \equiv c_W - \gamma$ as a technology cost. The adequacy cost is then defined as $\alpha \equiv \gamma - \beta$, the excess of market value over the system value. We

[18] Notice the emphasis on energy instead of power.

[19] It is assumed that the capacity of each technology adapts when the load curve changes.

have

$$c_W = \frac{C_D - C_Z}{T\mu_W} + c_W - \frac{C_Z}{T\mu_Z} + \alpha$$

By construction, the system value of wind does not depend of the strength of wind speed but exclusively on the precise moment at which wind is strong in percentage of average yearly strength. Since the adequacy cost is a thermal cost minus the system value, it is also independent of the capacity factor of wind in the system area. These values also appear to be quite insensitive to the scale of demand.

5 Results

5.1 Capacity Factors Puzzle

Country	Year	DE	ESP	DK	IT	UK	PT	FR	NL	AT	GR	IR	SE	BE	PO	FI	EU-15
Power (GW)	2006	20.6	11.3	3.1	2.1	2	1.7	1.5	1.6	1	0.7	0.7	0.5	0.2	0.2	0.1	48.0
Energy (TWh)	2006	30.4	22.9	6.1	3.2	3.7	2.5	2.3	2.8	1.6	1.5	1.5	0.9	0.4	0.2	0.2	81.0
Cap. Factor	2006	17.8	24.7	22	19	26	21	23	23	21	27	29	19	25	20	21	21.0
Cap. Factor	2005	17.3	26.0	24	18	30	25	20	21	21	29	31	21	16	22	23	21.1
Cap. Factor	2004	18.3	24.9	24	19	29	22	22	21	21	28	28	23	18	25	20	20.7
Cap. Factor	2003	16.3	23.8	21	20	25	23	22	19	15	35	31	21	20	31	22	19.7

Table 4: Capacity Factors in Europe

Most WPG studies[20] borrow Dale et al. (2004)'s $\rho = 35\%$ capacity factor; this estimate is based on computer simulations using wind speed data at candidate locations, not actual power output. Table 4 summarizes data from EurObserv'ER's wind energy barometer with some corrections from more reliable sources whenever available.[21] We use formula (3) to mitigate the continuous development of WPG, it thus yield greater capacity factors than the mere ratio of output to capacity in a given year. The discrepancy with the theoretical estimate is appalling since real capacity factors oscillate in the 20–30% range for massive wind power (above one percent of system capacity). The higher end is found in Greece, Ireland and UK (mostly Scotland) which benefit from windy costal areas. Although the figures we report here have been made public every year over the last decade by TSOs, the author does not know of any study or any mention in the literature of this bewildering divergence between observed capacity factors and the aforementioned theoretical level.[22]

[20] For instance Box 3.1 in Gross et al. (2006) or section 3.1 in SDC (2005).

[21] While there are only minor adjustments for installed capacity from year to year, generation data show important discrepancies among statistical sources, both between year to year reports of the same source and between different sources. We have favored the most recent reports and TSOs over European think tanks.

[22] The pro-wind lobby overemphasizes capacity installation and almost never mention energy output, let alone observed capacity factors. When it does, abnormal wind conditions in recent years are finger-pointed as the single elucidation for the wedge.

A partial answer for this puzzle is *shadowing*, a physical phenomenon that originates in the fact that wind parks compromise optimal distance between turbines to save on land cost or to pack many turbines over an high quality area of limited extension. As reported by Kaltschmitt et al. (2007) (cf. footnote 9), the output of a wind park is on average 92% of its nameplate capacity i.e., although a single 2MW turbine can yield 2MW under a large span of good wind speeds, a park of 50 units will never yield the nameplate capacity of 100MW but 92MW at most. Taking into account shadowing raises the capacity factor by 10% i.e., at the European level, we would find 23% instead of 21%.

At the EU level, the fact that the capacity factor is 21% and not 35% means that the real levelized cost of WPG is greater than popular estimates by two thirds since in the case of WPG, $AC_W = \frac{f_W}{\rho T}$ (cf. section 3.2) and the ratio of predicted to real capacity factor ρ is $\frac{35}{21} \simeq 1.66$.

5.2 Germany

There are four German Transmission System Operators whose control areas more or less coincide with federal states as shown on Figure 5.

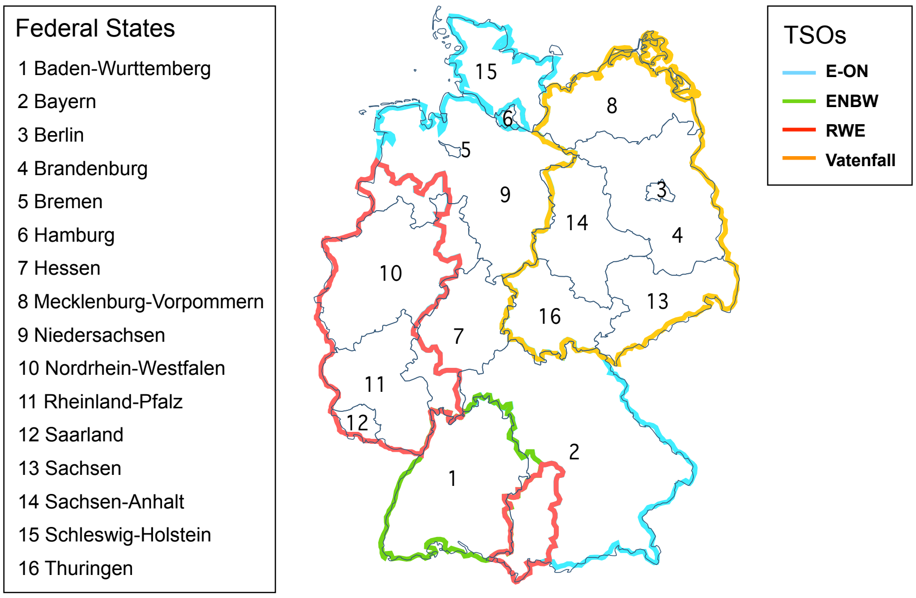

Figure 5: German TSOs and Federal States

Each TSO publishes the "wind energy" fed into its transmission grid and the load of their transmission grid (so called Vertikale Netzlast) which does not include any measure from the distribution grid and thus ignore distributed generation. To scale these data to country level, we use a rough mapping of landers to the four system areas shown on Figure 5, generation data from VDN, the association of German TSOs, and capacity data from EWEA (European Wind Energy Association) to build Table 5.

Although wind power contributes more than a sixth of installed capacity in Germany, its generation share is only 7% due to extremely low capacity factors across the years as reported in Table 6, using the mid-year capacity in the calculation as explained in formula (3). ENBW's dramatic 10% figure is due to the continental climate affecting its zone which happens to be the least developed

	Power	Energy	Cap. Factor	Load	Share
TSO	GW	TWh	%	TWh	%
EON	8.6	13.2	17.6	204	38
VAT	8.3	12.3	16.9	84	16
RWE	3.4	4.8	11.6	171	32
ENBW	.3	.3	10.3	80	15
Germany	20.6	30.6	16.9	540	100

Table 5: German Aggregate Data for 2006

in Germany (and ought to remain so). As a consequence of the low quality of the German wind resource, the levelized cost is currently twice the standard estimate (whatever that may be).

Year	2006	2005	2004	2003	2002	2001	2000
Capacity GW	20.6	18.4	16.6	14.6	12.0	8.7	6.1
Cap. Factor %	17.8	17.3	18.3	16.3	19.0	16.1	16.3

Table 6: German Capacity Factor of Wind

According to VDN, the price paid to wind power through the support mechanism has grown from 85€/MWh in 2000 to 96€/MWh in 2006. Since developers are still keen to add capacity, it must be the case that the levelized cost of wind power remains below this threshold.[23]

The analysis of time series reveals a system value of 28 and an adequacy cost of 13, stable over the two years of available data. The high technology cost value is a direct reflection of the country's low capacity factor.

[23]Alternatively, hidden subsidies may be present e.g., a loan from a local financial institution at below market rates

Year	2006	2007
vol. W (%)	10.2	9.3
vol. D (%)	4.3	4.5
vol. Z (%)	4.8	5.2
# <1% max W	6	0
mean duration	6.5	na
day of longest	24/04	na
starting at	7	na
duration	8	na
# >90% max W	4	7
mean duration	8.5	7.9
day of longest	01/11	18/03
starting at	4	4
duration	11	12

Year	2006	2007
Max D (MW)	87305	86492
Mean D (MW)	61644	59481
Peakness (%)	142	145
Capa W (MW)	19518	21434
max W (%)	77	87
G share (%)	5.7	7.6
K factor (%)	18	21
K credit(%)	7	9
K adequacy (%)	6	7
private cost	83.6	71.
sys. value	27.5	27.2
tech. cost	42.8	29.7
adequacy cost	13.3	14.1
therm cost	40.1	40.2
real cost	43.2	43.5

Table 7: German Results

5.3 Denmark

General Characteristics

Electricity demand in Denmark, both at the energy and power levels, seem to have stabilized as can be noted from Table 8; this is an indication that advances in efficient use of energy compensate for the natural growth associated with GDP growth. As can be checked from Table 9, this country holds the world's largest share of electricity generation from wind power. Since 2000, capacity has increased slowly indicating a possible saturation of available locations.[24] The current trend is the re-powering of old sites to save on land and connection cost. The fact that the capacity factor and also the maximum country output increased during the period 2000-05 might well reflect the switch to more advanced wind turbines able to run under a larger span of wind speeds. The volatility of wind is more than twice that of demand and impinges on the residual demand volatility since WPG serves a large share of load. Low wind events are scattered all along the year, their duration is stable across the years but their frequency seem to decrease which may be a by-product of using newer technology that generate energy under a greater span of wind speeds.

Looking at the Eastern and Western Denmark region separately, WPG volatility nearly double as well as the number of low wind events in the Western region holding one third of the country Wind Power capacity. The Eastern region is more windy and displays parameters value in line with the entire country.

[24] Capacity and yearly generation data from the Danish Energy Authority's wind register.

Year	2000	2001	2002	2003	2004	2005	2006	2007
vol. W (%)	14.9	14.3	13.5	14.	12.5	12.1	13.1	12.5
vol. D (%)	5.3	5.1	5.1	5.	5.	5.1	4.9	4.9
vol. Z (%)	6.2	6.	6.3	6.6	6.9	6.9	6.5	6.9
# <1% max W	32	33	24	31	16	20	19	17
mean duration	10.8	10.6	9.3	10.3	8.5	8.	11.9	15.4
day of longest	17/12	15/01	01/10	13/02	22/07	04/09	14/10	17/12
starting at	6	9	11	9	4	3	23	21
duration	28	35	33	25	21	19	33	35
# >90% max W	3	10	11	4	7	8	6	13
mean duration	11.3	8.4	10.3	8.2	9.6	13.2	11.7	8.
day of longest	14/12	15/11	06/03	27/12	19/03	06/01	13/12	19/04
starting at	10	10	2	15	19	21	23	11
duration	13	10	24	9	16	39	23	14

Table 8: Danish Results

Wind Economics

Table 9 displays the economically relevant results. The capacity credit is not constant in Denmark, looking at the top 3% hours of peak load, it varies from 16% to 33%. The adequacy index (computed with the same 3% threshold) is lower and more stable around 10% (range is 8–12). The adequacy cost has risen in recent years from a quarter to a third of the total cost of wind power thanks to a reduction of the technology cost.

Year	2000	2001	2002	2003	2004	2005	2006	2007
Max D (MW)	6284	6229	6257	6403	6227	6253	6423	6372
Mean D (MW)	3964	4016	3980	3975	3997	4048	4107	4121
Peakness (%)	159	155	157	161	156	154	156	155
Capa W (MW)	2072	2444	2694	3003	3120	3125	3131	3134
max W (%)	87	89	91	90	89	92	91	92
G share (%)	12.2	12.3	14.	16.	18.8	18.7	17.	19.8
K factor (%)	24	20	21	21	24	24	22	26
K credit(%)	35	24	20	21	29	31	36	29
K adequacy (%)	16	10	11	7	12	12	14	10
private cost	63.8	74.1	72.2	70.7	62.	61.9	67.2	57.4
sys. value	31.9	29.8	29.9	27.5	29.3	29.5	30.7	28.2
tech. cost	21.2	31.3	29.	26.8	18.2	18.1	23.9	13.2
adequacy cost	10.7	13.	13.3	16.4	14.6	14.2	12.6	16.
therm cost	41.3	41.3	41.4	41.3	41.1	41.1	41.1	41.
real cost	45.2	46.7	47.3	48.2	47.3	47.2	47.3	46.8

Table 9: Danish Results

5.4 Spain

Spain hosts Europe's second largest wind power capacity with over 13GW at the end of 2007. Table 10 presents the regions where wind power is most developed together with the average capacity factor over the 2003-2006 period (data source: REE annual reports). The Castille region altough very much used does not host strong wind in comparison with Navarra, Galicia or Aragon. The large geographical extension of this country implies that low wind events are rare but so are maximum ones.

Region	WPG share	Cap. Fac.
Galicia	22%	28%
Castilla la Mancha	20%	22%
Castilla y Leon	18%	23%
Aragon	13%	26%
Navarra	9%	28%
Andalucia	5%	25%
Rioja	4%	19%
Valencia	3%	21%
Catalonia	2%	23%
Spain	100%	25%

Table 10: Spanish Regions

Year	2004	2005	2006	2007
vol. W (%)	6.	6.1	6.8	6.6
vol. D (%)	4.3	4.7	4.1	4.2
vol. Z (%)	4.7	5.2	4.7	4.8
# <1% max W	0	1	0	1
mean duration	na	5.	na	9.
day of longest	na	28/02	na	04/02
starting at	na	7	na	15
duration	na	5	na	9
# >90% max W	2	6	1	2
mean duration	8.5	7.7	6.	8.5
day of longest	28/10	27/10	08/12	19/03
starting at	13	14	13	12
duration	10	12	6	11

Year	2004	2005	2006	2007
Max D (MW)	38000	43000	42000	45000
Mean D (MW)	26869	28176	28958	29780
Peakness (%)	141	153	145	151
Capa W (MW)	7232	9075	10514	12304
max W (%)	66	61	74	70
G share (%)	7.2	8.5	9.	10.
K factor (%)	27	26	25	24
K credit(%)	26	35	19	27
K adequacy (%)	20	27	15	19
private cost	55.5	56.7	60.5	61.7
sys. value	32.1	35.5	31.6	33.
tech. cost	15.3	15.8	19.6	20.7
adequacy cost	8.2	5.4	9.3	7.9
therm cost	39.6	40.5	40.1	40.1
real cost	41.3	42.3	42.7	43.

Table 11: Spanish Results

5.5 Portugal

Portugal displays results quite similar to its neighbor Spain, in particular the contiguous Galicia region. The development of WPG is recent but strong and already account for 8% of the electrical energy consumption. We also have the unique opportunity to look at photovoltaic data for 2005-2007 where power rose from 3MW to 14MW. We extrapolated these small figure by a 100 factor to simulate.

Year	2005	2006	2007
vol. W (%)	14.3	15.1	14.9
vol. D (%)	4.9	4.8	4.7
vol. Z (%)	5.2	5.2	5.4
# <1% max W	10	5	9
mean duration	7.	6.4	10.9
day of longest	22/01	10/02	04/02
starting at	7	17	3
duration	12	10	41
# >90% max W	4	4	4
mean duration	6.	5.8	9.5
day of longest	01/12	23/11	19/12
starting at	24	22	13
duration	7	8	12

Year	2005	2006	2007
Max D (MW)	8513	8779	9090
Mean D (MW)	5473	5609	5706
Peakness (%)	156	157	159
Capa W (MW)	792	1364	1894
max W (%)	74	75	81
G share (%)	3.6	5.9	7.9
K factor (%)	25	24	24
K credit(%)	29	21	31
K adequacy (%)	25	18	21
private cost	59.9	61.7	62.6
sys. value	35.4	32.1	33.2
tech. cost	18.7	20.1	21.
adequacy cost	5.8	9.4	8.4
therm cost	41.	41.	40.9
real cost	41.9	42.7	43.3

Table 12: Portuguese Results

The portuguese TSO also records photovoltaic electricity production, that although fairly small, is large enough to support a statistical study. The absence of sun during 12 hours every day reduces the solar load curve by half. To enable comparison with wind and demand, we delete the night hours of the solar load curve and present the three curves over common time axis. Likewise, we normalize each maximum to unity to obtain a common vertical axis. As can be seen on Figure 6, the solar load curve is much more sustained than the wind one and even more than the demand one. This means that solar energy, once present is durable (e.g., many hours a day) and repetitive (e.g., many sunny days). Using the current installed 15MW, we compute a 32€/MWh system value that decreases by 2€ only, if we artificially inflate the capacity a hundred fold, at which point solar power reaches a 4% share of electrical energy consumption.

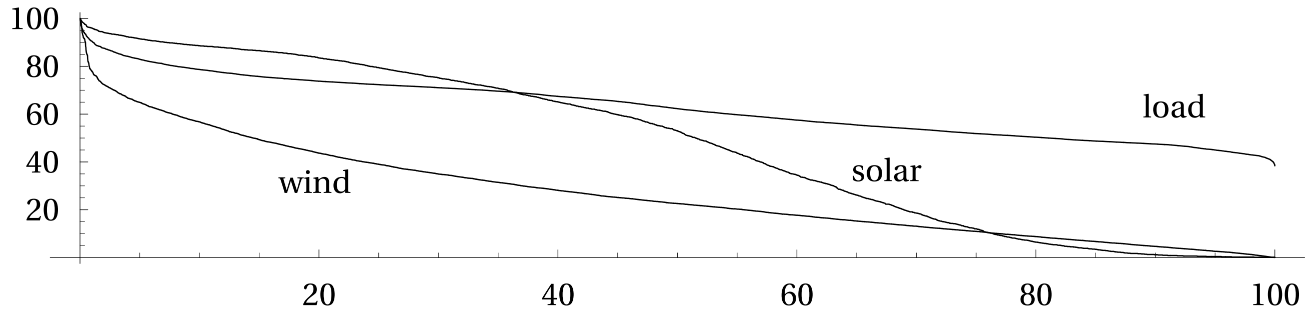

Figure 6: Comparative load curves

5.6 Eire (rep. of Ireland)

Over the period 2002-2007, electricity demand in Ireland, both at the energy and power levels, grew at 3% per year, faster than population growth (1%) but less than the GDP growth (6%). This indicates a moderate use of comfort equipment such as electric heater or air conditioning in the household segment and a reliance on services rather than industry in the business segment.

Our results are reported in table 14. Installed wind power capacity grew at the sustained rate of 30% per year and now accounts for 5.5% of total electricity generation. The capacity factor was initially very large and has been varying (2004 was a low wind year) but remains around 30%, by far the largest value in our sample of countries. The capacity credit is larger than the capacity factor indicating a high correlation between wind and demand. The adequacy index, which is more severe by nature, is still extremely large, indicating that wind is quite reliable in Ireland. There is no doubt that this is one of the better places on earth to develop further wind power.

The levelized cost of wind power is around 40€/MWh and the adequacy cost is below 5€/MWh, even slightly negative one year. The system value of wind power is the largest among the sample, confirming in monetary terms, the value of the Irish wind resource. For Ireland, there were more than 30 "wind chill" events in 2002-04 but only 7 in 2005-06 which confirms the view that an extensive scattering of turbines across the land is guarantee to always have power.

Year	2002	2003	2004	2005	2006	2007
vol. W (%)	21.4	28.4	24.7	16.1	14.2	13.2
vol. D (%)	5.	5.	4.9	4.9	4.9	5.
vol. Z (%)	5.1	5.	5.	5.1	5.2	5.4
# <1% max W	23	29	30	6	8	8
mean duration	21.7	12.3	15.1	9.	7.1	8.5
day of longest	01/01	01/09	11/05	15/02	07/06	06/09
starting at	1	18	2	4	4	2
duration	231	51	54	17	12	17
# >90% max W	13	9	5	3	6	7
mean duration	9.9	9.	11.	5.3	8.3	8.6
day of longest	10/03	24/12	29/12	29/12	13/12	18/05
starting at	14	9	21	6	14	10
duration	34	18	15	6	12	17

Table 13: Irish Results

Year	2002	2003	2004	2005	2006	2007
Max D (MW)	4317	4326	4464	4768	4979	5032
Mean D (MW)	2781	2859	2923	3054	3197	3244
Peakness (%)	155	151	153	156	156	155
Capa W (MW)	130	168	264	411	620	798
max W (%)	92	65	85	92	88	89
G share (%)	1.7	1.6	2.	3.9	5.6	6.6
K factor (%)	36	27	21	29	29	27
K credit(%)	43	36	33	38	36	39
K adequacy (%)	40	34	31	33	31	32
private cost	42.2	55.8	68.9	52.3	52.1	55.5
sys. value	37.5	38.2	40.9	36.9	36.1	36.2
tech. cost	1.3	15.1	28.3	11.3	11.	14.3
adequacy cost	3.3	2.5	−0.3	4.1	4.9	5.
therm cost	40.8	40.7	40.6	40.9	40.8	40.9
real cost	40.8	41.	41.1	41.4	41.7	42.2

Table 14: Irish Results

5.7 Marginal value of WPG

To assess the impact of increasing WPG in a system, we rescale up and down our data points to generate larger samples. Letting (D, W) represent one year of hourly data for a given system, we compute the system value β_λ of WPG in the imaginary world $(D, \lambda W)$ for λ varying in $[\frac{1}{2}, 2]$ and we match it with $g_\lambda = \lambda \frac{\mu_W}{\mu_D}$, the share of electricity demand that WPG would cover. We proceed for all the available years in order to generate the largest possible number of data points that we fit with least squares to produce a country formula for the social value of WPG as an affine function of its contribution to electricity demand i.e., $\beta = \bar{p} - c \times g$. The intercept $\bar{p}$ is the country's idiosyncratic system value of WPG whereas the absolute slope c is the fatigue rate, the value lost with incremental presence of WPG. Our results are displayed in Table 15.

Area	DK	DE	ESP	IRL
$\bar{p}$	34.2	28.7	35.7	39.7
c	0.25	0.20	0.27	0.56

Table 15: Idiosyncratic system value and fatigue rate

If demand and wind speed patterns were constant across the years, our estimate β_λ would match the observed values when the installed wind capacity increases. The fact that such an hypothesis must be rejected can be seen on Figure 7 where a single share g_λ is matched with several system values. This is mostly visible on the Danish graph because capacity there is quite stable over the last four years so that yearly variations of wind (demand seems much more stable) give rise to a large range of system values.

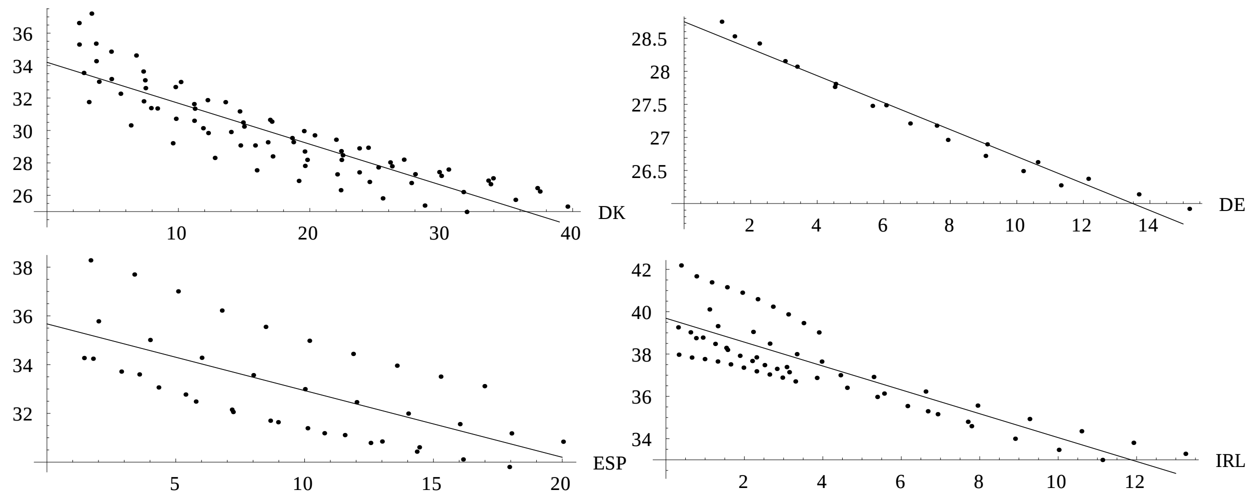

Figure 7: System Value of WPG

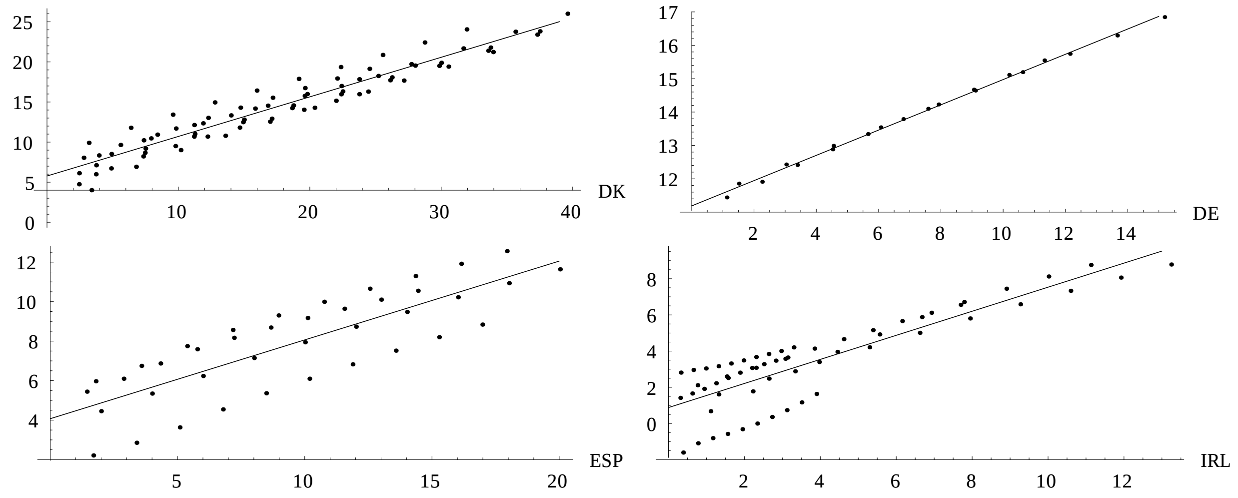

Figure 8: Adequacy Cost of WPG

5.8 Geographical Aggregation

Our last experiment is to consider Germany, Spain and Denmark as a single area, as if transport capacities were unbounded. In 2006, this wide system gathered 35GW of wind power out of 44GW installed in continental Europe (excluding UK, Ireland and Greece). The aggregation process smoothes out the peakedness of demand and cuts in half the volatility of wind output (high and low wind events are nearly non existent). Regarding cost, the system value averages at 31€ over the 2006/7 period whereas the adequacy cost is at 9.7€. If we further add France to our database, we come close to study the real western europe continental electricity system.[25] We find a greater system value at 32.3€ and a lower the adequacy cost is 8.2€. Comparing with the country findings reported on Figure 8, we see that geographical integration enables to bring down adequacy cost to a minimum of 8, twice less that the individual country value (at foreseeable levels of penetration).

These findings confirms the intuition according to which the contribution of wind power is larger, the larger the geographic area under consideration. For that reason, interconnection capacity should grow in parallel to wind capacity to allow sudden bursts of WPG to be transported far from their inception towards urban areas where demand is located.

6 Conclusion

Adding large amounts of wind power in an electrical system generates reliability and adequacy problems. There is now agreement that modern electronic control technologies are able to solve the first problem at a moderate cost. The interest in "credit capacity" arose from the second issue, adequacy. We have shown that both the traditional measure of "credit capacity" and its monetization were inadequate; we have offered two concepts of adequacy, an index expressed in percentage

[25] The French hourly load is made available by the TSO but the wind output is not yet published; we thus increase the joint capacity of the other countries by 5% to proxy French WPG output.

of the wind capacity and a cost expressed in €/MWh that can be applied to hourly data for estimation.

Overall, wind power generates a sizable social cost going up to two third of private cost but meanwhile the thermal generation industry is competitive, it will supply the residual load curve at minimum cost. That is to say, the generation mix will evolve optimally. It would nevertheless be advisable to sit wind turbine where they render the greatest service i.e., where their social cost is minimum which incidentally is also where their private cost is smallest. In the current landscape of national schemes, this translate into the recommendation that German wind power developers go abroad and sit turbines in Ireland or Scotland and then sell its green output into the German market using physical exchange contracts.

A Security of Supply

Adequacy vs. Reliability

According to North American Energy Reliability Council NERC (2007)'s glossary,

- *Adequacy* is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements".
- *Reliability* is "the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements".[26]

Adequacy is a planning or long term problem whereas reliability is an operational or short term problem. A rough estimate of adequacy is the "system margin" measuring the difference between currently available capacity and estimated demand peak. An ample adequacy eases the treatment of contingencies (sudden disturbances) and thus increases reliability but an extremely reliable system may still become inadequate to serve a demand that grows faster than new plant additions. From an economic point of view, Oren (2003) notices that reliability is a public good whereas adequacy is a private good.

The reliability service is "non-rival" because once the cost of upgrading an equipment is sunk, the entire system becomes more reliable, the benefit is not only for those directly connected to the equipment but to all having a connection to the system because security spreads according to the laws of physics not those of men. Likewise, the reliability service is "non-excludable" in the sense that there is no way to control or limit who benefits from greater system wide reliability.

The case for adequacy is radically different. Adding generation or transmission to the system increases adequacy, so that the ability to consume power is increased at some locations and reduced at none. There is "rivalry" here because whenever the extra power is used by a glass maker, it is not anymore available to a car maker. There is also "excludability"; this is quite obvious for generation

[26]Dictionaries define *adequate* as enough to meet a purpose whereas *reliability* is the quality of being dependable or trustworthy. We thus adhere to the above definitions and not the UK ones where reliability is called balancing and adequacy is misleadingly termed reliability.

because it is technically possible to match a financial transaction between the generator and her client with the physical transaction whereby power is injected into the system by the generator and taken away by the client even-though they are quite far away from each other. Even additional transmission is excludable; indeed, the owner can sell rights to use the link if the TSO cooperates to implement that scheme.

Prior to deregulation, the two tasks were performed by the same vertically integrated utility which lead to an identical "public good" perception. More to the point, adequacy was treated as a public service[27] i.e., a private good supplied by the community (through the utility) to the community because of its positive external effects. This meant that hidden cross-subsidization was taking place. Indeed, the adequacy cost of meeting ever growing demand at any time was socialized on a yearly basis (accounting for both energy and power) which never (statistically speaking) coincides with the willingness to pay of users for additional capacity.

Reliability levels

As noticed early on by engineers, the intermittence[28] of wind power precludes it from contributing much to the reliability of the entire system. As a consequence, some switchable generation sources are needed as "back-ups" to maintain reliability at the standard level. What is at stake here is the ability for the system operator to guarantee at every minute that any demand at any node within his control area will be met even if unexpected event takes place e.g., a failure at a generation plant, a human mistake in the control room, the breaking down of a transmission line, a software bug in the central computer system or a wind storm that forces all windmill to shut down to protect themselves.

In practical terms, reliability is measured by the loss of load probability (LOLP) or equivalently by the expected number of loss of load hours (LOLE) per given (lengthy) period of time. Standards are quite divergent around the world. The NERC standard is "one day in ten year" LOLP i.e., the probability of a failure to serve some (may be all) clients be less than $\frac{1}{3650}$. The Irish figure is "eight hours of loss per year" i.e., $\frac{1}{1095}$. The British standard before liberalization was to ensure blackouts on no more than nine winter peaks in a century; although this concept has never been elucidated in the literature, one could interpret it as a probability of $\frac{1}{9733}$ for a one hour event. The French criteria is "three hours per year" i.e., $\frac{1}{2920}$. The Dutch criteria is "one two hours LOLE every four years" i.e., $\frac{1}{17532}$ while the belgian one is "16 hours per year" i.e., $\frac{1}{547}$. In any case, the level of reliability commonly experienced in advanced economies is at the top end of the sample.[29]

[27] Health and education are private goods often mistaken for public goods because they are public services. They involve rivalry because the human labor involved (doctor, teacher) is directed solely on the client and the possibility to exclude entrance at school or hospital, although it may seem outrageous to most, is feasible at low cost.

[28] In this paper *intermittence* refers to the fact that the power output of a wind turbine can severely drop or jump within seconds or stand still for hours before turning back to full power.

[29] The small power outage we suffer from time to time are mostly due to failures in the distribution system i.e., outside the TSO's responsibility.

B Data Sources

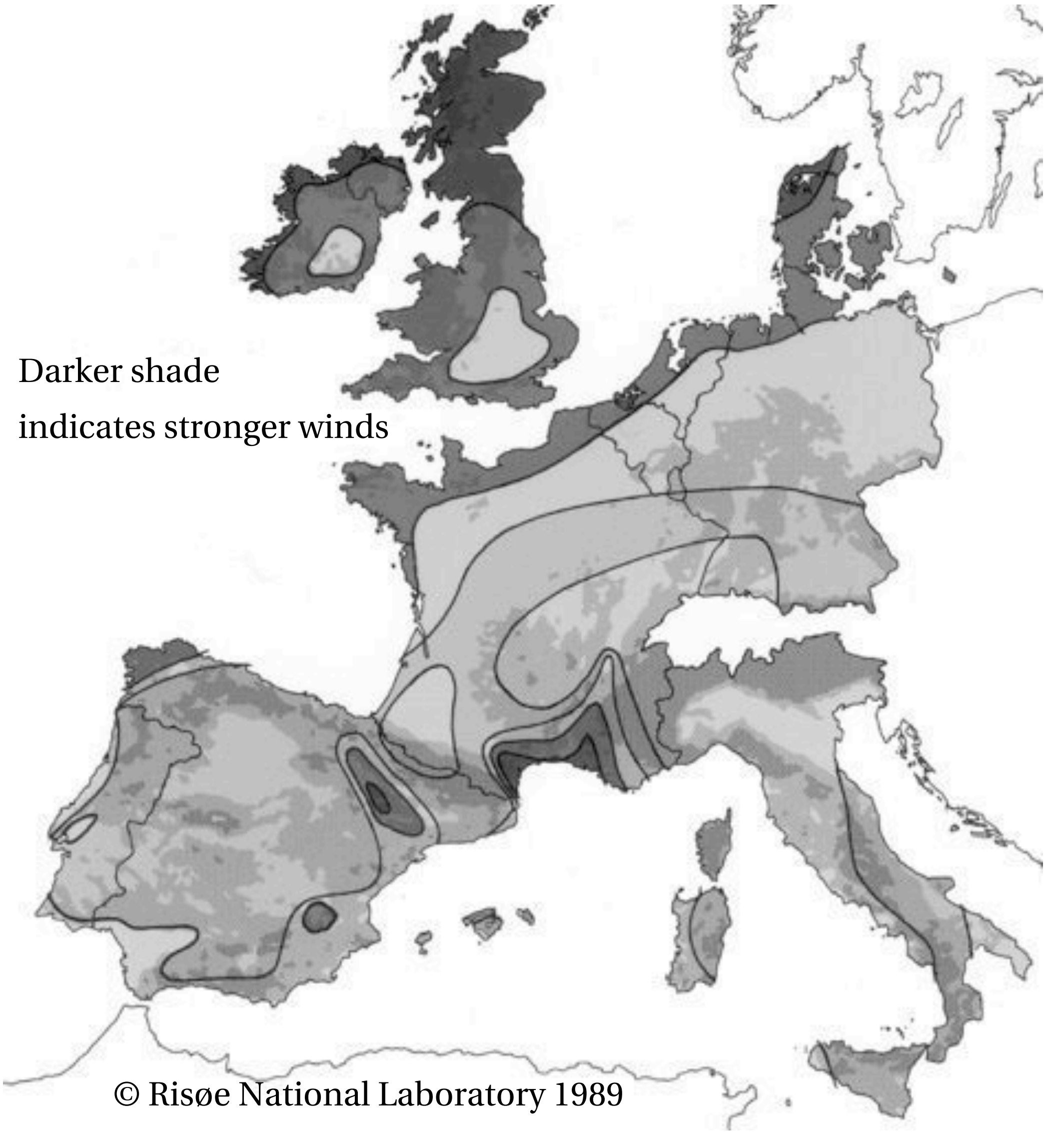

Figure 9: Western Europe Wind Map

Transmission System Operators

- Danish TSO energinet
- SouthWest German TSO ENBW in German: click on *Windenergieeinspeisung* for wind data and on *Vertikale Netzlast* for Load
- NorthWest German TSO RWE in German: bottom of the page, click on *Winddaten* for wind data and on *Vertikale Netzlast* for Load
- North German TSO EON : choose Excelsheet at the bottom of pages Load and Wind
- Eastern German TSO Vattenfall in German: choose *Vertikale Netzlast* for load data and *Windenergieeinspeisung* for wind data.
- Spanish TSO REE: no download area, only graphical display of daily outputs

- Irish TSO Eirgrid: choose *system demand* and *wind generation* in 3 months blocks
- Portuguese TSO REN: daily load curve and daily wind output curve (in Portuguese)

Market Operators

- Scandinavian NordPool
- German Energy Exchange EEX (futures on EU ETS)
- Spanish Pool Omel

Miscellaneous

EU-DEEP

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