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Large-scale wind power in European electricity markets : time for revisiting support schemes and market designs ?

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Summary : This paper questions whether current renewable support schemes and electricity market designs are well-suited to host a significant amount of wind energy. Our analysis aims at finding the right equilibrium between market signals received by wind generators and their intrinsic risks. More market signals are needed to give the right incentives for reducing wind integration costs but should not undermine the effectiveness of support schemes. Although several alternatives combining support schemes and market signals could improve the current situation in terms of market signals and risks, feed-in premium support scheme seems actually to be the more balanced option. Furthermore, an adequate sharing of wind generation technical responsibility between the System Operator and wind power producers can help to control wind integration costs even in the absence of accurate market signals.

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1. Introduction

Wind power technologies in Europe have benefited from renewable promotion policies for more than ten years. Renewable policies have been implemented through different support schemes such as feed-in tariff, feed-in premium or green certificates. Successful support schemes have been acknowledged by their ability to boost the initial deployment of desirable renewable technologies (Butler and Neuhoff 2008; Del Rio et al, 2007; Ragwitz et al, 2007; Mitchell et al 2006). Nevertheless these support schemes kept wind power technologies aside from day-to-day operation of electricity markets and henceforth act as an isolating device to complete and transparent market signals. This has been judged as acceptable stage to the initial development. Indeed when wind power capacity in the system is relatively low, the wind integration costs due to the characteristics of this technology (variability and low predictability) are also low and can be absorbed by the rest of market participants.

Following the EU Renewables Directive and the 3x20 target, wind power capacity in Europe has entered in a new large-scale development phase. Among European countries Spain, Germany and Denmark stand out by their impressive growth over the last decade. In these countries wind power capacity represents between 18% to 24% of the total installed capacity. Resch et al (2008) consider that Germany would have about 34 GW, France about 24 GW and Spain around 28 GW in 2020. With the increasing share of wind energy in the energy mix, wind integration costs inevitably rise and their impacts on both the power system and the electricity markets are becoming of an utmost importance. In this second stage of large-scale wind power development, support schemes and electricity market designs need to be assessed and adjusted in order to give the right incentives to all generators (renewable and conventional) while maintaining fair benefits for any other renewable technology but also in reducing the social costs paid by end-users. The following question then arises: how to identify what constitutes the right equilibrium between right market signals in one hand and the associated increased risks generated by these signals in the other hand ? More market signals are needed to give right incentives for reducing wind integration costs but should not undermine the effectiveness of support scheme (encouraging investment and limiting capital costs).

Recent studies have investigated the participation of renewable technologies on electricity markets and the impact of market designs on power systems with large scale of renewables. Klessmann, et al (2008) analyzes pros and cons of exposing renewables to electricity market signals and make a comparison between support schemes through the analysis of three countries: Germany, Spain and the UK. They conclude that exposing renewables to market signals, particularly non-intermittent technologies (e.g. biomass), would be beneficial for the total social cost on the condition that this does not dramatically increase the renewable producers' risk and therefore the support payment. However, they do not find considerable benefits to expose wind power technology to market signals (or risks) because of the lack of short-run responsiveness of this technology. A limit of this work stands in the lack of consideration of electricity market design as a possible variable to better adjust market signals and to promote efficient large scale wind power integration. Barth et al (2008) and Green (2008) consider how electricity markets should be designed to improve the incentives given to market participants in order to maximize their efficiency by reducing wind integration costs. These last two papers, however, do not consider the interaction between support schemes and electricity markets.

The contributions of this paper are three fold. First this paper studies electricity market designs in the light of the potential and necessary improvements required for the large scale integration of wind power. Second it adds a new layer to the actual research on the interaction of support schemes and electricity markets through a deeper study of market signal impacts on wind generators' behavior. Finally this paper uses this new framework to determine what could be a good balance between market signals and risks and to discuss how the current support schemes and market designs can be adapted.

The paper is organized as follows. Section 2 briefly presents the support schemes used for wind power in Europe. Then the integration costs related to large-scale development of wind power are identified and the impacts of the electricity market design on these costs are discussed. Incentives and market signals provided by short-term forward markets (day ahead, intraday), balancing markets, congestion (and losses) pricing and connection and network tariff are analyzed. Section 3 focuses on the design of different support schemes to assess their adequacy with market participation and market rules. We first analyze to what extent wind power producers should participate in electricity markets. Then we analyze market participation for three support schemes: fixed feed-in tariff, feed-in premium and green certificates. Section 4 concludes with some policy recommendations concerning the trade-off between support mechanisms and market responsibility to ensure well functioning electricity markets and system.

2. Large-scale development of wind energy

2.1. Wind power support schemes in Europe

Renewable support schemes drive the actual and future deployment of wind energy technology. After ten years of renewable support policy experience, three main support mechanisms can be distinguished: the fixed feed-in tariffs, the feed-in premium and the green certificates[1]. Table n°1 shows support schemes used in some countries in Europe. Feed-in tariff is the most used support mechanism in Europe (European Commission, 2006). Feed-in tariff scheme guarantees a fixed price for the total wind energy amount fed into the grid. This price is usually higher than the electricity market price and the difference represents a premium for the positive environmental externalities generated by windmills.

Table 1. Support schemes in selected countries

Countries	Support schemes
Denmark	Feed-in premium added to the market price
Spain	Either a feed-in tariff indexed on the regulated price for 20 years or a feed-in premium + market price for 20 years
Germany	Fixed feed-in tariff for 5 years then 15 years with decreasing tariff
France	Fixed feed-in tariff for 10 years then 5 years with decreasing tariff
Netherlands	Feed-in premium to add to the market price or reference price (SDE) since 2008
UK	Renewable obligation certificate (ROC) price to be added to the market price

[1] Other types of support schemes as tendering procedures or investment subsidies are not considered here since they are not often used in Europe.

A variant of feed-in tariffs is the feed-in premium scheme. Under this scheme, wind power producers receive the electricity market price and a fixed regulated premium for producing renewable energy. This feed-in premium scheme may include a cap-and-floor limit that guarantees minimum and maximum tariffs independent of the electricity market price thus reducing the overall risk. For instance, fixed feed-in tariffs and feed-in premiums are possible options in Spain but more than 97% of wind power producers have chosen the last option. Feed-in premium has been preferred because the total income from market price and premium is usually higher than the fixed feed-in tariff.

Green certificate scheme is based on the level of renewable generation obligations generally imposed on suppliers. To fulfill these obligations, suppliers can either produce (internally or externally) “green electricity” or buy the equivalent in green certificates. Green certificates are produced each time an accredited renewable energy source generates. For instance, in UK, each MWh produced by wind power plants generates one ROC (Renewable Obligation Certificate). Wind generators then sell their production on electricity markets and green certificates on a specific certificates market. If suppliers do not fulfill their renewable obligations, they must pay a penalty: the buy-out price. The level of this buy-out price is of importance for the effectiveness of the support scheme since the incentives to achieve renewable targets can be distorted[1] (Mitchell et al, 2006).

Implementation of support schemes facilitates a high penetration of wind power in several European countries. A higher level of wind power capacity brings many benefits in terms of reduction of GHG emissions, increasing diversification and security of supply, developing new sustainable technologies for the future, developing new industries, etc (Lamy, 2004). These benefits are notably higher than the costs of support schemes[2] and other negative externalities (use of the land, landscape, etc). As wind power technology has specific generation characteristics (variability, low predictability, wind resources far from consumption sites, etc.), other costs are added into the power system; costs that have to be taken into account in order to adjust adequately support schemes and electricity market designs : the integration costs.

2.2. Integration costs of wind power

Integration costs represent additional system-induced costs due to the integration of large-scale wind energy. These integration costs can be separated into i) balancing costs, ii) reliability costs iii) congestions (and losses) costs and iv) network connection and reinforcement costs (Gross et al 2006). Additional balancing costs come from wind power intermittency and will affect both the unit commitment of the conventional power plants and the increasing need for balancing the system.

[1] If the level of the buy-out price is too low, suppliers could find cheaper not to respect renewable obligation rather than buy ROCs on markets. In theory, the buy-out price should set the cap of ROCs market. However, in practice, the ROC price is higher than buy-out price because the amount of money paid by suppliers not respecting obligations is recycled to suppliers respecting obligations. ROC prices are therefore quite difficult to predict, they can create distortions and are sensible to opportunistic behavior.

[2] The cost of support schemes corresponds to the difference between the renewable and conventional technology generation costs. In the long run, this difference should decrease since the learning curve evolution of renewable technologies becomes more competitive. In terms of generation costs, wind power generation cost is around 56€/MWh whereas the CCGT cost is around 45€/MWh (UKERC, 2007)

Balancing costs increase because the system needs more reserves and balancing services, all of which will be used more frequently. Using additional quick start capacity and conventional power plants running part-load are the main reasons of cost increase[1].

Additional reliability costs are associated to the weak contribution of wind power to peak situations and to the corresponding variability of wind power generation during these periods. When intermittent wind generation replaces conventional generation, an additional installed generation capacity is needed to get the same level of reliability (e.g. a given value Loss of Load Probability). Additional congestion (and losses) costs are due to higher and different use of the network mostly when wind power generators are located in remote areas that are usually far from the load. Moving cheap electricity over large distance can generate potentially more losses and more frequent occurrences of bottlenecks, which increase losses and congestion costs. The latter increase because both the lead time of construction of wind plants is much lower than the time required to increase the network capacity.

The integration of wind power into the power system implies also connection costs and network (transmission and distribution) reinforcement costs. Connection costs are due to the additional installations (underground cable, etc.) required to connect the wind power plants to the existing transmission and distribution network. In addition, the connection of new wind farms can need upgrades and reinforcements on the bulk network. Reinforcements on the network to accommodate wind energy flows reduce additional congestions and losses costs; minimizing the net sum of both integration costs is necessary to improve the efficiency of the system.

2.3. Electricity market architecture as the key for the distribution of integration costs

As the amount of intermittent generation increases on the system, taking additional integration costs into consideration become more and more relevant as the incentives to reduce them have to be incorporated to the analysis of efficient support schemes. The analysis of electricity market architectures helps to clearly identify how integration costs can be controlled and how they are distributed using different market design options to give signals to market participants.

The electricity market architecture. Electricity is a complex good, largely constrained by physical and technical laws for its production and transmission on the grid (Stoft, 2002). The introduction of competition needs the design of specific market architecture(s) or market design(s) (Wilson, 2002). Given system operation constraints, a “standard” market, where supply matches directly demand, cannot manage the complexity of a power system in real time. A centralized authority, called the “System Operator” (SO), is responsible for real-time management. Therefore, “standard” markets, where generators, intermediaries (traders, brokers) and large consumers trade electricity each other are normally “forward” markets[2] i.e. they take place before the moment of delivery.

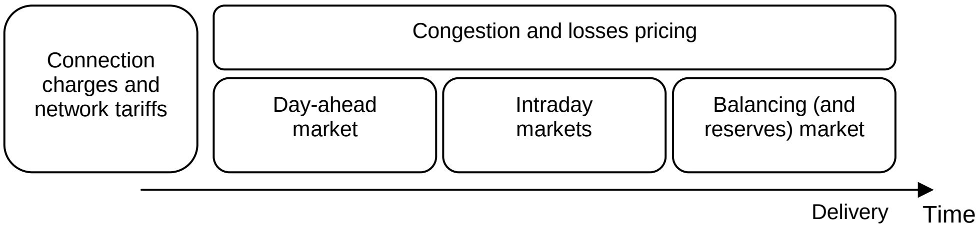
[1] Several studies have demonstrated that increasing share of wind energy in system load results in higher balancing costs (Holttinen et al, 2007; Gross et al, 2006; DENA 2005). For wind energy penetration from 5% to 20% of gross energy demand, system operating costs increase due to wind variability and uncertainty amount for about 1-4€/MWh depending on the observed system (Holttinen et al, 2007).
[2] Forward markets are financial markets that trade electricity ahead of its delivery.

In the short run, forward energy can be traded in the day-ahead market (functioning 24 hours before delivery)[1], in intraday markets (functioning within the day) or even in real-time in the balancing market.

Other services may be defined in the market architecture in order to better represent the operation of the power system[2]. An efficient use of transmission networks requires the implementation of market mechanisms to reduce congestions and losses. These mechanisms and related costs send economic signals valuing the use of scarce network capacity resources and other externalities (Ehrenmann and Smeers, 2005). Transmission and distribution activities present features of natural monopolies mainly due to network costs mostly composed by fixed costs. Hence, scarcity (marginal) pricing framework does not enable the full network costs recovery.

Therefore regulated connection charges and network tariffs are applied to network users in order to ensure the viability of the network services. Figure 1 sums up typical electricity markets that, in a general meaning, have been organized as follows: short-term forward energy markets (day-ahead and intraday), congestion (& losses) pricing, balancing market and connection and network tariffs.

Figure 1. Electricity market Architecture



Each of these markets or mechanisms could be defined by different rules and designs. Not all designs have the same economic properties concerning incentives and efficiency (Wilson 2002). The market design will determine the "quality" or "accuracy" of market signals. Furthermore, depending on the market architecture and SO arrangements, the responsibilities of system operation can be shared between the market signals or SO authority.

[1] Forward markets have maturities that go from 3 years to a few hours before delivery. We focus on Day-ahead market because day-ahead prices are a major benchmark for all forward trades.

[2] Reserves and long term capacity mechanisms are not considered explicitly in this paper.
-Some (fast) generation capacities have to be prepared as "reserves" before real-time in order to prevent blackouts. The reserve mechanisms represent tools that the SO runs in short term to manage the security of the network. In electricity markets, reserves are market driven through the balancing market. As reserves and balancing are the two faces of the same coin, we consider both under the term balancing market.
-Long term capacity mechanisms (e.g. capacity markets, capacity payments) are sometimes added to the market architecture in order to ensure an adequate level of generation capacity (Joskow, 2006). As these mechanisms are not broadly used in Europe, they are not considered in this paper.

Day-ahead and intraday markets. The most liquid market in electricity is the day-ahead market. As the traded electricity products correspond to 1 hour or ½ hour periods, market signals given through this market allow to value electricity differently according to the delivery times during the day[1]. Intraday markets allow trading electricity from day-ahead market closure to few hours before delivery.

The degree of centralization of day-ahead and intraday markets is the key element to distinguish different market designs (Wilson, 2002). These markets can be organized from a centralized auction (e.g. Spain) to a completely decentralized bilateral market (e.g. UK). More centralized markets concentrate trades and increase market liquidity. They can also optimize generation power scheduling by incorporating uncertainties and intertemporal and network constraints[2]. Therefore, more centralized designs can help improve coordination and dispatch efficiency, and reduce wind power integration costs (Green, 2008). Most of European markets are based on bilateral transactions and on a power exchange accounting for less than 10% of the power consumption. They are not well equipped to minimize wind integration costs since decentralized coordination does not allow for an optimized generation scheduling.

The temporal position of the “Gate Closure” is another important design parameter, mainly in more decentralized markets. The Gate Closure determines the closure of the forward (intraday) markets and the opening of the balancing market. A Gate Closure that closes intraday markets near real-time help to decrease individual imbalances and wind integration balancing costs. When market participants are able to trade electricity near real-time, it implies that better information concerning the actual wind power generation is available to all the market participants (Barth et al, 2008). Müsgens and Neuhoff (2006) show that a gate closure near real time would reduce the balancing costs, since fewer thermal power stations would be started up, only to be ready to replace previously unexpected wind power outputs.

Balancing market. The balancing market is managed by the SO. On the one hand, the SO balances the system using balancing offers/bids and reserves. On the other hand, the SO computes imbalances (measuring the actual injections/withdrawals of energy in real-time and comparing it with forward contract positions) and settles them using imbalance prices. Balancing market signals indicate the real-time (spot) value of electricity for each settlement period at the time of delivery. Forward signals are only based on expectations while real-time signals integrate both new information coming after forward markets and the value of flexibility (Barth et al, 2008). Balancing signals should be cost-reflective in order to induce efficient behavior. Balancing signals indicating the marginal cost of balancing the system and enable individual market participants to compare their own cost to reduce imbalance against the cost of buying balancing services from the system. This helps market participants to take efficient decisions. If this is not the case, two different inefficient situations can appear.

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[1] For instance electricity produced during off-peak hours (during the night) is cheaper than electricity produced during peak hours. Other products including aggregated hours are also commercialized in forward markets (e.g. base or peak blocks).

[2] Centralized day-ahead market in US use optimization tools to clear the market respecting very detailed power plants constraints (e.g. start up costs, ramping constraints, etc.) implying a better use of generation resources.

Either inappropriate high imbalances charges will lead market participants to use individual balancing options (e.g. own back up thermal plant) increasing the total balancing cost, or excessively cheap balancing charges will give incentives to market participants to over-use balancing services and this will undermine efficiency.

One of the most important design parameter of balancing markets is the definition of imbalance prices. This will determine how the total balancing costs are distributed and how incentives are given to market participants. There are basically two types of design : a dual-price design and a single price design[1]. The dual price imbalance design is reputed to be less cost-reflective than the single price design[2] (Newbery, 2005). As a matter of fact dual imbalances prices are usually computed using average prices and artificial penalties added to imbalance costs. As the system balancing cost does not depend on individual imbalances but on the total net imbalance, positive or negative individual imbalances need to have the same price. On the other hand, single price design is reputed to give more volatile signals since imbalance price is computed using the proposed price of marginal offer or bid and this can change for each settlement period. Dual-price settlement system is used in several European countries and some of them are renowned not to be cost-reflective (ILEX, 2002; Littlechild, 2007). However many countries are improving market design in order to get balancing signal right (Vandezande et al, 2008).

Short term and long term locational signals. The goal of congestion (and losses) short-term pricing and connection and network tariffs is to give locational signals indicating the costs/benefits for the whole system of the production/consumption of energy in each node of the network. Short-term congestion (and losses) pricing is often integrated with the energy markets[3]. There are different possible designs of pricing depending on the aggregation of signals: i) nodal pricing, ii) zonal pricing and iii) redispatching. Nodal pricing establishes one energy price for each node in the network while redispatching gives the same price of energy no matter where it is injected or withdrawn. In the latter case, the system operator takes action to solve congestions (and minimize losses) and the costs of this action are socialized among network users. Most of European countries use a redispatching design that gives no short-term locational signal[4]. The choice of the degree of differentiation depends on two issues. On the one hand, more differentiated pricing gives more locational signals indicating where and when to produce or consume. On the other hand, less differentiated pricing reduces the transaction costs and the induced risks on the revenue of market participants (Ehrenmann and Smeers, 2005). Furthermore, this trade-off concerns the degree of delegation of power to the transmission system operator (TSO) and the extent of system operation authority. The lesser short term locational market signal are given to the market participants, the more the TSO has to intervene ("out of the market") to solve congestions problems.

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[1] The dual-price balancing mechanism design uses two different prices for negative and positive imbalances. These prices are often computed using average prices of accepted bids/offers. The single-price real-time market design uses only one price for all types of imbalances and this price correspond to the price of the marginal accepted offer/bid.
[2] It is important to note that defining optimal balancing rules is not straightforward given costs allocation problems (e.g. no proper imbalance measure, non-convexities, inter-period costs and fixed costs allocation). However, good practice guidelines exist in literature and have to be applied in order to give proper incentives (see for instance Littlechild, 2007; Vandezande et al, 2008).
[3] This is called "implicit auctions" and consists in computing energy electricity prices taking into account transmission constraints and transmission losses.
[4] Italy and Scandinavian countries are two exceptions using zonal pricing.

Network connection charges and network tariffs are complementary payment mechanisms used to cover the total cost of transmission and distribution infrastructure and, potentially to give long-term locational signals to generators. Several designs are possible for network connection charges going from “shallow cost” design (where the new connected installation only pays the cost of the own connection to the system) to “deep cost” design (where the new connected installation pays all the extra network cost due to its connection)[1]. Network connection charges designs can be combined with different designs for transmission (distribution) network tariffs which can include long-term locational signals for generators. Using different combinations of network tariffs and connection charges designs, the locational signals, the burden allocated to generators and the associate risk can be balanced.

At one extreme, “shallow cost” and weak (or no) network tariffs do not provide any locational signals but minimize the risks and the extra costs for generators. At the other extreme, “deep cost” design gives locational signal to generators but, as proper and transparent deep cost signals are very difficult to estimate, this might make generators to over react choosing not efficient locations or increasing the risk.[2] Zonal network tariff design gives good locational signals and involves less risk than “deep cost” solution (Rious et al, 2008).

Charging congestion (and losses) and reinforcement costs to the responsible parties incite market participants, both wind power and conventional, to reduce as such the integration cost of wind power. Wind power characteristics imply that the patterns and the frequency of congestions changes constantly and hence the role of short-term signals becomes very important for the efficiency of the system. The absence of locational signals in the presence of high amounts of wind power can considerably increase congestion (and losses) costs.

In fact, without locational signal, conventional generators continue to schedule production and to plan their location without taking into account transmission network impacts and the System Operator has to make a greater effort to control congestion (and losses) implying a higher integration cost. Introducing nodal/zonal pricing could help to reduce these integration costs (Weigt et al, 2008; Leuthold et al, 2008). However, as more accurate market signals as nodal/zonal pricing are more volatile, this can increase the risks born by market actors. Table 2 summarizes the main options of market design and the accuracy of market signals and related risks.

Different designs send different signals to market participants. Thus, distribution and control of wind power integration costs depend on different market designs. Efficient designs need accurate market signals to give the right incentives. In Europe there is considerable room to improve market design and accuracy of market signals. However, accurate signals imply more volatile revenues and therefore an increase of risks. If the risks are too high, this creates a negative investment effect mostly on technologies with high capital cost.

[1] For a more detailed assessment of connection cost policy: Barth, et al, 2008; Rious et al, 2008; Swider et al, 2006).

[2] Deep connection cost design involves more risk than other design options. At the beginning of an investment project, the producer has high uncertainties concerning connection charges. These charges could be high and depend generally on unclear TSO/DSO rules. Investments can be deterred if the financial cost provoked by this risk is too high.

Table 2. Market design, market signals related risks

	Potential market signals	Potential integration costs reductions	Market design options		Accuracy of market signals*	Risk induced by market signals*
Day-ahead and intraday markets	Temporal differentiation of electricity	Balancing and reliability costs	Degree of centralization	Decentralized	0	0
				Centralized	+	-
			Gate closure	Far real-time	0	0
				Close real-time	+	-
Balancing market	Value of electricity at delivery/ Value of flexibility	Balancing and reliability costs	Imbalance price	Dual price	0	0
				single price	+	+
Congestions (and losses) pricing	Locational/ temporal differentiation	Congestion and reinforcement costs	Zonal aggregation	Redispatching	0	0
				Zonal	+	+
				Nodal	++	++
Connection and network tariffs	Locational/ temporal differentiation and cost recovery	Congestion and reinforcement costs	Connection and network tariff	Shallow	0	0
				Deep	+	++
				Zonal tariff	++	+

Note: * 0 indicates the reference case and corresponds to more typical market design in Europe. +/- indicate more or less market signal accuracy or risks with respect to the reference case.

The adequate trade-off has to be done to find a good balance between increased market responsibility and risks. This is true for all types of markets participants (conventional generators, renewable and demand) but particularly for wind power technology given the most important differences with conventional technology which is their ability to manage risks. In the case of wind energy, investors are quite sensitive to risks which could prevent such investment.

3. Market signals under different support schemes

The choice and implementation details of support scheme have implications on the way that wind power producers participate into markets and are exposed to market signals. We first analyzed why wind power producers should be exposed to more market signals and then how each type of support scheme efficiently transfers (or not) these signals.

3.1. Do wind power producers have to be exposed to market signals ?

Enforcing wind power producers to participate in electricity markets or exposing them to market signals entails several positive effects which are balanced by few negative effects. It has been argued that, as wind power technology has no means to react to market signals, it is not useful to expose them to it (Makarov et al, 2005, Klessmann et al, 2008). This is partly true in the short-run because wind power production has a high incentive to produce whenever wind is blowing and without regarding to the electricity price given its null (or very weak) marginal cost.

However, there is still a set of long term positive effects that can be found if one analyzes market signals and their effects more deeply. With the objective of a significant increase of wind energy in Europe by 2020, longer term effects cannot be ignored. Positive effects of exposing wind power producers to markets signals can be summarized as follows:

- **Optimal selection of wind sites related to temporal generation pattern.** Forward prices and balancing signals differentiate time-delivery periods i.e. time periods when energy is highly valued (peak periods) have higher prices. As wind sites have different wind generation patterns, adequate selections of wind sites should take into account the different temporal value of energy expressed in forward and balancing market signals.

- **Optimal selection of wind sites related to congestion costs and losses.** Wind power producers subject to locational signals should choose the wind sites that are more advantageous not only in terms of wind resource but also of capability of the network (Forsund et al, 2007, Barth et al, 2008, Di Castelnouvo et al, 2008). Installing wind power plants in highly windy areas may not bring high benefits if there is not enough transmission capacity to transport all the produced energy or if the extra losses induced by wind power production reduce considerably the useful energy. For instance, short-term congestion (and losses) pricing should give an indication of the zones where new power production can be accepted and therefore incite investors/producers to make an arbitrage between more congestions (and losses) costs and lower wind resource sites.[1] This is particularly important for wind power given the leadtime gap between the build of wind mills and reinforcing transmission networks and congestions can remain for long periods. Short term locational signals can be replaced or completed by reinforcement network investments. Locational network tariffs or cost-reflective connection costs may act in the same direction than short-term locational signals; although network tariffs loose some of the (temporal) accuracy of short-tem signals, they reduce considerably the congestion (and losses) cost risk.

- **Improvement of maintenance planning**. Market participation of wind energy on forward and balancing markets implies higher responsiveness to price levels when implementing maintenance planning[2]. If wind power producers do not receive the right signals for planning maintenance, they might operate the maintenance when there is a lot of wind or when the wind energy is more valuable for the system.

- **Improvement of technology combinations and portfolio effects.** Time differentiated electricity prices give signals for the optimal combination of geographically distributed wind power installations and the optimal combination of wind power production and other production technologies (intermittent such as solar or geothermal or storable such as hydro power plants).

[1] In some cases wind power projects can also help to reduce congestion, losses or to postpone network investments but as they are not remunerated for this side-benefit, they prefer to choose another wind site.

[2] Suppose that a wind power producer has to select one moment of the day to stop its wind turbine and undertake the maintenance tasks and suppose also that forecasted wind production is constant over the day. Under a feed-in tariff scheme, the wind power producer has no preference in selecting maintenance hours during the day.

These signals also allow to assess the short-term flexibility and storage options of the different technologies. Technology combination and innovation can result from an improvement of coordination between different technologies (wind/storage, wind/hydro, etc.) or from a new “firm organization” structure (size of the firm, portfolio type, etc.). Indeed, exposing all market participants to equal market signals for all technologies allows market actors to create efficient portfolios combining different kinds of technologies.

- **To control (reduce) production for extreme case of imbalance and network constraints.** With high amounts of wind power in a system, it could be possible to have negative prices (Weigt, 2006); i.e. power producers are paid to reduce their production. This can happen during extreme congestion periods (under nodal pricing) or when the system has too much energy and there is not enough flexibility to reduce production of conventional units (for instance at night, coal plants produce at minimal capacity because they do not want to stop and start). In these cases, if wind power producers are exposed to adequate market signals (balancing or nodal pricing), they will reduce their production in their own interest and will contribute to the operation of the system. Note that even with the absence of market signals, other centralized and mandatory command-control alternatives can be implemented to improve wind power response (e.g. mandatory obligation of connecting wind farms to local dispatch controls).

- **Improving controllability by innovation.** Participation of wind power energy in markets can provide good incentives for more controllability and innovation. By controllability & innovation we mean all the actions that can be implemented to make wind power technology more similar to a conventional technology (e.g. new control system, IT installation, more centralized dispatch, etc) (Verhaegen et al, 2006). Innovations may appear also in windmill design by favorising more constant and controllable generation against only a maximal output objective**.**

- **Improving individual forecasting & system balancing efficiency.** One of the reasons given to encourage the market participation of wind energy and to support equal balancing rules for all market participants is that this encourages the wind power producers to provide accurate predictions for system operation (Mitchell et al, 2006). If wind power producers have to pay for their imbalances, they will invest in forecast tools in order to reduce their balancing costs and therefore to maximize their profit. Wind farm owners can provide more accurate forecasts of their own production since they know the machines’ availability and could run downscaling programs with detailed information from the field the terrain in order to increase the predictions’ accuracy. A detailed prediction of each farm is particularly important in some special cases, for instance, when considering grid constraints violation. Although wind power centralized forecasting is needed[1], improvements on individual forecasting can be translated into system balancing efficiency. Two conditions are needed for that: i) wind power producers give good forecasting information to the System operator and ii) the System Operator uses all the scheduling information to reduce the cost of system balancing.

[1] This is because balancing cost depends on total forecasting error (demand, conventional generation and wind power) and the accuracy of an overall forecast is much higher than those of an individual wind farm due to “the large numbers” effect. The large numbers effect is very important in wind forecasting. The error reduction induces the wind farms to concentrate themselves on an only bid or schedule, or on a few ones.

- **Transparency of the support schemes.** If wind power producers participate in electricity markets as other conventional technologies, they have to support (a part of) the integration costs from their intermittent production (balancing, congestions, etc.). These extra costs have to be included in some way in the support scheme in order to avoid creating a barrier for wind power. Including integration costs in the support scheme clearly identify the real costs of the subsidy for each of the proposed new technologies and avoid cross-technology subsidies and consequent distortions. Excluding wind power producers of system-induced charges may imply extra costs for the transmission and distribution system operators and finally for the network users since these costs are socialized. This could lead to an under-evaluation of the necessary subsidy for the development of wind power energy and a problem of acceptability.

Negative effects of exposing wind power producers to market signals are :

- **Increase of risks of wind power producers.** The revenue of wind power producers that need participating in forward and balancing markets is more risky than the revenue ensured by the feed-in tariff. As for other market participants, wind power producers will face market risks since they face volume and price risks for their output. Wind technology costs are mainly composed by fixed costs, and particularly by capital costs. Such market risks incur a huge investment risk that could deter investment in wind farms.

- **Transaction costs increase.** Participation in markets implies more transactions costs than those incurred in the feed-in system. First, the producers have to understand the complex electricity market architecture and have to be able to understand and react to different signals sent by markets. The incurred transaction costs are of importance for small players. This is particularly the case for wind farms since they are usually small size plants (up to 50 MW for onshore wind farms)[1]. Nevertheless learning-by-using should lower theses transaction costs since complex operations can become routines.

Considerable potential gains exist from exposing wind power producers to market signals. However it can increase risks and transactions costs for this particular segment of generators and to the system and society in the end. These two opposite factors have to be balance in order to integrate large amount of wind power in a socially efficient way. There exist several intermediate solutions for exposing wind power producer to market signals, depending on the support scheme implemented and if there is specific market rules applied for wind power producers.

[1] Note that the transaction cost increase depends mainly on the industrial organization of wind power producers. If wind power plants belong to incumbents or big electricity companies, the transaction costs increase should be low since these companies hold all skills to participate on markets and they will just add wind energy to their generation portfolio. Conversely, if wind power plants belong to independent power producers, the transaction costs should be higher since producers should learn how to participate on markets and how to react to market signals.

3.2. The adequacy between support schemes and electricity markets

In order to figure out the interactions of wind power producers with electricity markets and market design we build up our analysis following Klessmann et al (2008). They study how wind power producers are exposed to market signals (or risks) under three different support schemes: i) fixed feed-in tariff, ii) feed-in premium and iii) green certificate. For each support schemes, we analyze how wind power producer are exposed to "market" signals respectively in forward markets (day-ahead and intraday), balancing markets, congestion (and losses) pricing and connection and network tariffs.

Feed-in tariffs scheme

- **Forward markets signals**. With feed-in tariff wind power producers do not realize electricity transactions as other conventional producers, i.e. wind power producers do not participate in day-ahead/intraday markets and are not exposed to short-term forward market signals. Wind power producers are set aside of markets; both the price and the sold volume are guaranteed for their output.

- **Balancing market signals.** Concerning the balancing market, we distinguish two types of feed-in tariff implementations: i) feed-in tariff without balancing responsibility and ii) feed-in tariff with balancing responsibility. In the first case, the wind power producer does not bear the balancing responsibility since the electricity production and injection on the grid is made without any special obligation automatically (e.g. France, Germany). Integration costs due to intermittency are generally born by the system operator then spread over network users. This reduces completely the risk of balancing costs of wind power producers while it does not give any balancing signals to them. In the second case, balancing responsibility for wind power producers is included as a feed-in tariff rule. Wind power producer has to provide a load-profile before the time of delivery and the imbalances are computed following this load-profile (e.g. Spain). A feed-in tariff with balancing responsibility scheme can be combined with specific rules for imbalance charges applied to wind power in order to arbitrate between the balancing signals and balancing cost risk.[1]

- **Short term and long term locational signals.** Feed-in tariff scheme isolates wind power producers of eventual short term locational market signals since they do not participate on electricity market. However, feed-in tariff scheme may be combined with different designs of connection and network tariff. "Shallow cost" design of connection policy minimizes the risk and the cost burden of wind power producers but does not give any long-term locational signal while a more "deep cost" approach gives long-term locational signal at the expense of higher risks and cost burden for wind power producers. The impact of different connection and network tariff designs depends on how these costs have been taken into account on the definition of the level of feed-in tariff or at the

[1] For instance, wind power producers under feed-in tariff scheme in Spain have particular balancing rules. They have a fixed (regulated) imbalance price (7.8 €/MWh) and this price applies to the deviation between scheduled and actual delivered volume beyond fixed tolerances. For wind and solar energy, the tolerance margin is 20% (Rivier, 2008).

regulatory level. In some cases renewable energy producers do not pay for connection charges since it has been decided at the legislative level.

Feed-in tariff scheme is well-known to reduce uncertainty in revenue of wind power participants (Dinica, 2006; Mitchell et al, 2006). However, as feed-in tariffs give the same price for the electricity produced in all hours, this scheme does not give any signals of temporal valuation of energy[1]. Suppose that two locations are candidate to install a wind farm. Both locations have the same average wind speed levels but a different temporal production pattern. One site would produce more energy during night and the other site would produce more energy during the day. Under a feed-in tariff scheme, the investor has no preference for any site because he will have the same remuneration in both sites. From a system point of view, the optimal choice is the wind site producing more energy during peak hours. Therefore wind sites contributing to reduce the reliability system cost could be not chosen at first. Moreover, this scheme does not give signals for an optimal maintenance organisation. Concerning balancing, some implementations of feed-in tariff can give some signals which will imply some improvements in individual generation forecasting, controllability and transparency of the support scheme costs.

As wind power producers do not participate on energy (locational) markets, they do not have to support any short term locational signal[2]. Hence wind sites originating congestions (and losses) may be selected indistinctly by wind power producers. This implies higher additional congestion (and losses) costs. However, a feed-in tariff policy scheme combined with connection and network tariff designs whose focus on providing adequate locational signal[3] could help to lead optimal location of large-scale wind power generation.

Feed-in tariff scheme alone gives weak incentives to control (reduce) generation under extreme congestion or imbalance situations. The opportunity cost for wind power producers to reduce production is the value of the feed-in tariff, which is based on the average total cost of wind not related to the expected conditions of the system. However specific rules concerning the right of disconnection/shortage can be implemented to deal with congestions or other stability problems in the short-term (e.g. Spain, Portugal[4], Germany[5]). This could happen in case of emergency and this decision could be taken exclusively by the SO in order to ensure the well-functioning of the system. This fact can illustrate the trade-offs between the authority of the SO and the market responsibility of participants.

[1] Recently, a few implementations of feed-in tariff have included different payment for different time of the day (Klein et al, 2008). This introduces some differentiation in the value of energy at different hours. If this differentiation is related to the real effects of injections into the system at different hours, this can give some signals to wind power producers.

[2] Note that although some feed-in tariff implementations give different prices for different regions, it does not correspond to locational signals indicating where is better for the system to install wind power farms but to reduce windfall profits of zones with very good wind resources.

[3] "Over-sized" locational signals can avoid the development of wind projects. This is the case for instance with the "deep cost" connection rule where the wind power developer has to pay the cost of all reinforcements made in the network after the new installation.

[4] In the case of technical problems, the system operator is allowed to interrupt wind farms production during valley hours (50h/year) (Peças Lopes, 2008).

[5] In Germany, the congestion management implies a curtailment rule: the network operator is allowed to curtail the output of renewable energy if the network is already congested. This rule has huge implications for the producer's income. In 2005, this curtailment rules would decrease the wind power producer revenue by 5% (Klessmann et al, 2008).

Feed-in premium support scheme

- **Forward markets signals**. Under feed-in premium support scheme, wind power producers have to participate in forward markets as other market participants. The energy produced at each hour is valued differently and proportionally to the hourly electricity market price. Furthermore, wind power producers receive a regulated premium for each kWh sold (and produced) that represents the value of the positive externality of the renewable use.

- **Balancing market signals.** Participation in the balancing market is also required since wind producers follow the same rules than the other market participants and therefore, they receive balancing market signals. They have to pay balancing charges if their production in real time differs from their contractual position in the forward markets. It is possible however to apply specific balancing rules for wind power (Rivier, 2008). These rules may consist in setting up tolerance values of balancing volume under which there is no cost of imbalance or in applying a fixed (regulated) imbalance price to reduce the uncertainty related to market based imbalance prices[1].

- **Short term and long term locational signals.** Wind power producers may have the same obligations and signals than other participants or particular rules. Feed-in premium scheme may also be combined with different designs of connection and network tariffs.

The total revenue under this scheme is relatively more volatile than the fixed feed-in tariff. Nevertheless, the income risk can be limited in using a cap-and-floor mechanism. This mechanism implies that the market price plus the premium has to be set between a lower and an upper limit[2]. This cap-and-floor mechanism brings a revenue warranty and limits seriously the price risk. Floor limits are particularly appropriate for investors who can continue to invest since they are able to determine a minimum return on their investments[3].

Under feed-in premium, wind power producers are exposed to the market signals so that they can adopt more efficient behavior. On forward markets, they have the possibility to value wind power depending on the particular time they are producing. Thus an investor will choose wind sites with more potential production during peak hours in order to increase his revenue. This contributes to reducing the extra reliability system cost induced by wind power[4]. Wind power producers should plan efficiently the maintenance of wind farms since their revenues depend on the moment when they are disconnected. Concerning balancing signals wind generators have incentives to improve forecasts of wind energy and to improve controllability of wind farms as they will have to support balancing costs. Furthermore, as the

[1] For instance, in Spain, the wind power producers under the premium scheme do not have to pay any charge for secondary reserve.
[2] For instance, in Spain, the market price plus the premium must be contained between at least 71.27€/MWh (lower limit) and 84.94€/MWh (upper limit).
[3] Note that this income warranty is only a price guarantee given that there is not a volume guarantee since wind power producers have to find a counterparty on markets.
[4] This is strongly related to the so called “capacity credits” of wind generation. Selecting wind power sites with high production in peak hours corresponds to maximize the capacity credits of the wind generation and to minimize the over-cost of adequacy (see for instance Gross et al, 2006).

opportunity cost of not producing is mostly based on the "environmental premium" and on the expected condition of the system, wind power producers are more likely to reduce production when the system operator needs it. Finally, wind power producers can be exposed to the same short term locational signals than other market participants and this can contribute in the efficient selection of wind sites. It will be consistent with existing long term locational signal whatever the design.

Green certificates support scheme

- **Forward markets signals**. Under green certificates, wind power producers have to participate in forward markets as other market participants. The energy produced at each hour is valued differently and proportionally to the hourly market price. Furthermore, wind power producers receive a market-based premium for each kWh sold (and produced) that represents the value of the positive externality of the renewable use. This market-based premium is the green certificate price which is de facto more volatile than the administered one. This introduces in the one hand a more accurate signal of the scarcity of green production but in the other hand news risks and transaction costs.

- **Balancing market signals.** Participation in the balancing market is also required since wind producers follow the same rules than the other market participants and therefore, they receive balancing market signals. They have to pay balancing charges if their production in real time differs from their contractual position in the forward markets. It is possible however to apply specific balancing rules for wind power as in the premium feed-in price (Sioshansi et al, 2008, Makarov et al, 2005). These rules may consist in setting up tolerance values of balancing volume under which there is no cost of imbalance or in applying a fixed (regulated) imbalance price to reduce the uncertainty related to market based imbalance prices[1].

- **Short term and long term locational signals.** Wind power producers may have the same obligations and signals than other participants or particular rules. Green certificates scheme may also be combined with different designs of connection and network tariff.

The total revenue of wind power producers under green certificates support scheme is considerably more volatile with respect to feed in tariff and premium. Indeed the revenue depends on the green certificates prices which can vary considerably during the lifetime of a wind power plant (about 20 years). Furthermore, the existence of a buy-out price (the penalty that has to be paid by suppliers not fulfilling their green quantity obligations) complicates the estimation of the certificates price and increases again the risk. On the top of these support scheme risks, wind power producers have to bear the risk of participating in the electricity market. Even if wind power producers are exposed to electricity market signals which improve the incentives, the relative very high risk can increase considerably the cost of capital of wind power investments. Therefore only projects backed by long term contracts or

[1] For instance, the case of California is one example of specific balancing rules for wind power producers. Wind power producers included in the PIRP (Participating Intermittent Resources Program) have to schedule their energy in the forward market without incurring hourly or daily imbalance charges when the delivered energy differs from the scheduled amount. They are instead subject to imbalances charges accounted for monthly imbalances (Makarov, et al 2005). In Belgium, where a green certificates scheme is applied, balancing responsibility for wind is also limited as there is a tolerance margin of 30%.

under vertical arrangements will be undertaken which may limit considerably the wind power development (Finon and Perez, 2007).

Table 4 summarizes the main points of the interaction between support schemes and electricity markets. There are many possibilities of support schemes and market designs and combinations to expose wind power producers to market signals with different sharing of integration costs. Table 4 presents a subset showing the accuracy of market signals, risks induced by market signals and main revenue risk for a combination of support scheme and a benchmark of market design. This benchmark is characterized by a more centralized market, a gate closure near real time, one single imbalance price, zonal pricing and zonal network tariffs which correspond to a realistic efficient market design for Europe.

Table 4. Support schemes, market signals and risks

		Feed-in Tariff		Feed-in Premium		Green Certificates	
	Market design options	**Accuracy of market signals**	**Risk induced by of market signals**	**Accuracy of market signals**	**Risk induced by of market signals**	**Accuracy of market signals**	**Risk induced by of market signals**
Day-ahead and intraday markets	Centralized	0	0	+	-	+	-
	Gate Closure Close real-time	0	0	+	-	+	-
Balancing market	single imbalance price	0/+*	0/+*	+°	+°	+°	+°
Congestions (and losses) pricing	Zonal pricing	0	0	+	+	+	+
Connection and network tariffs	Zonal network tariff	++	+	++	+	++	+
Main Revenue Risks		Low		Medium		High	

°possible specific rules for wind power. * feed-in tariff with balancing responsibility

Table 4 shows also that from the policy maker's perspective, there is a trade-off between exposing the markets participants to a more accurate signals approach and a "low risks/transaction costs" approach. When renewables face high market risks and transactions costs, a higher level of financial support is required to stimulate renewable development than in a low risk and transaction cost environment. But the exposure to market signals may also give an incentive to make efficient use and development existing infrastructures and recent innovations, thus limiting the indirect costs to society.

Furthermore, support schemes have to take into account these extra costs resulting from combinations that expose wind power producers to market signals. The support schemes have to include some "normal/efficient" subsidy for integration costs (e.g. efficient wind balancing costs). Wind power producers will participate in the market and face with a part of their integration costs but without stopping development. Theoretically, green certificate scheme includes naturally this extra subsidy because the price of certificates adjusts itself in order to give enough revenues to wind power producers on condition that capacity investment is in line with the target capacity (this is not true if the penalty or the buy-out price is fixed too low). Conversely, feed-in tariff and feed-in premium schemes need to consider in their tariff definition a normal/efficient target of integration cost. In this case, participants with improved behavior earn extra profit and participants having worse results than normal/efficient have a loss.

4. Policy recommendations and conclusions

Policy recommendations to promote an efficient integration of large amounts of wind power into the system can be summarized in three points:

1. Readjust support schemes in order to increase the participation of wind power producers in markets and their exposition to market signals;
2. Improve market designs and market signals to avoid distortions;
3. Counter-balance recommendation 1) and 2) with the potential increase of transaction costs and generated risks for market investors.

Support schemes should be designed to give more market signals to wind power producers. Market signals to wind power producers can be beneficial to improve the selection of wind sites (considering temporal patterns, congestions and losses), to improve maintenance planning, to improve the combination with other technologies, to incorporate portfolio effects and to add transparency concerning the total cost of promotion policy, etc. The feed-in premium seems to be the best trade-off solution because this option allows enjoying the benefits of exposing wind power producers to market signals without creating considerable new risks and transaction costs.

While European Directives set ambitious targets concerning the penetration level of renewable energies, promotion policies have to be adapted in order to make it possible for renewable energy producers to be more sensitive on market signals. With high penetration levels, wind power cannot be set anymore aside of market signals and market participation. Nevertheless, market participation does not have to create entry barriers for such investments. A trade-off between support schemes and market participation has to be done at the regulatory level. Nowadays, two main issues have to be addressed. The first one concerns the “adaptability” way to smooth the passage between a low risk approach (the common feed-in tariff without balancing responsibility) to a more risky support scheme where producers can participate to markets and react on market signals. Several intermediate steps can be possible. One way to ensure investment while encouraging producers to act on markets is to let the choice to wind power producers to benefit from either a fixed feed-in tariff with balancing responsibility or a feed-in premium scheme while indirectly encouraging the latter.

Softer “specific rules” for wind power producers (e.g. setting up of tolerance margins for balancing settlement) can be used to limit the risk of being exposed to market signals. The second issue is to find the accurate equilibrium between what has to be managed by the SO and what can be managed through wind power producers’ market responsibilities. Transferring specific wind generation responsibility to the SO (by means of dispatch centers) can contribute to more wind energy deployment in the absence of accurate market signals. What happened in Spain represents one of the best compromises between market signals, low risk and adequate sharing of wind generation responsibility between market wind power producers and the SO.

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