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Large amounts of wind power in Europe: time for revisiting support schemes and electricity market designs?

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Abstract

This paper questions whether current support schemes and electricity market designs are well suited to host a significant amount of wind energy within a power system. Our analysis is structured in two main questions: i) do wind power producers have to participate in electricity markets and do they have to be exposed to market signals? and ii) are current market designs adapted to accommodate large amounts of wind power? The conclusions of the paper include two majors policy recommendation. Firstly, there is a need for support schemes with improved market signals for wind power producers. Secondly, there is a need for better designed markets. The paper elaborates on what that means. The paper is timely as Europe is facing large scale deployment of wind on top of the already large investments that we have seen the last years.

Keywords: Electricity Markets, Market Design, Renewable Support Schemes, Wind Power.

JEL Codes: L94, D43, Q42, Q48

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1. Introduction

Wind power technology is playing an increasingly important role in the power system and cannot be considered anymore as marginal. All European countries set ambitious levels of renewable energy in their generation mix and in their energy consumption (European Commission, 2006).

Wind power technology has benefited from renewable promotion policies implemented by several support schemes (feed-in tariff, green certificates, etc.). The development of wind power technology has been undertaken in parallel with electricity industry liberalization and the development of electricity markets. Electricity is a complex good and markets to commercialize it have to be properly designed. Electricity market architecture (or market design) is the key element in the functioning of electricity industry and theoretically, its main goal is to give right incentives to market participants to act and coordinate as a benevolent social planner would do (Stoft, 2002; Wilson, 2002).

These two parallel processes - wind development and electricity liberalization - have not been perfectly blended. Initially, the main issue of renewable policies concerned the way to promote the development of desirable forms of generation. Thus effective and low risk support schemes (such as appropriate feed-in tariffs) are well-suited to start the development of renewable technology (Butler and Neuhoff 2008; Del Rio, et al, 2007; Ragwitz, et al 2007; Mitchell et al 2006). However, these support schemes kept away wind power technology from the electricity markets and wind power producers do not receive any market signal or incentives (Klessmann, et al, 2008). Moreover, electricity market designs have not been considerably adjusted in order to accommodate this new technology. This may be acceptable for the initial step of development and when the amount of wind power capacity in the system is not important. In that case the impact of intermittent technology on the markets and the induced system costs coming from the specific characteristics of this intermittent technology (variability and low predictability) are low and can be absorbed by the rest of market participants.

Nowadays, wind power technology knows a dramatic take-off and a large amount of capacity has been installed in Europe. The impact of this intermittent technology on the system cannot be neglected anymore and incentives given to market participants to control these costs have to be revisited. In this second step of renewable development with large-scale wind power, support schemes and market designs should be adjusted in order to give incentives to all market participants (renewable and conventional) while maintaining fair benefits for any renewable technology but also reducing the social costs paid by end-users. To that purpose, two main concerns have to be analyzed. Firstly, actual support schemes do not allow wind power producers to see market signals (Klessmann, et al 2008). Secondly, the observed electricity market designs often deviate considerably from the theoretically optimal design and can give wrong signals leading to an inefficient functioning of the electricity system (Ehrenmann and Smeers 2005; Newbery 2005). When integrating large-scale wind power, these inefficient behaviors could be reinforced and higher distortions might arise (Woyte 2008, Barth et al 2008).

This paper revisits wind power support schemes and market rules under the presence of large-scale wind energy. We address the incentives and market signals that could be provided to wind power producers for their participation on short-term forward markets (day ahead, intraday), balancing markets and for congestion (and losses) pricing under different support schemes. The analysis is structured under two main questions: i) do wind power producers have to participate in electricity markets and do they have to be exposed to market signals? and ii) are current market designs adapted to accommodate large amounts of wind power? We argue that 1° support schemes have to be properly set in accordance with the incentives provided by the electricity markets and that 2° market designs have to be adapted as well, particularly when targeting high amounts of wind energy in the near future.

The paper is organized as follows. In section 2, after a brief presentation of the current situation of the integration of wind power in Europe, we analyze the interaction between support schemes and electricity markets. Sections 3 and 4 focus respectively on the first and second question. Section 5 concludes by some recommendations for policy-makers concerning support schemes and market design.

2. Wind power in electricity markets: the European case

1.1 Overview of wind power situation in Europe

The development of wind energy in Europe strongly depends on the support schemes and economic instruments that have been applied. Among European countries, three of them stand out by their impressive growth: Spain, Germany and Denmark. The development in the other countries seems to be slower and in general, wind energy does not exceed more than 3% of the total served demand in spite of good wind resources. The following table shows the penetration level of wind energy in several European countries: Denmark, Spain and Germany represent the three leaders of wind energy development; France has one of the best wind resource; Netherlands and UK have implemented green certificates whereas the four others have chosen feed-in tariff policies.

Table 1. Penetration of wind energy in different countries.

	Denmark (2006)	Spain (2007)	Germany (2007)	France (2007)	Netherlands (2007)	UK (2007)
Total installed power (MW)	12,699	85,959	114,153	115,900	21,000	84,000
Wind power (MW)	3,125	15,145	22,247	2,454	1,746	2,389
% total installed capacity	24.6	17.6	19.5	2.1	8.3	2.8
% yearly consumption	21.2	11.8	7.0	1.2	3.4	1.8

After ten years of renewable support policy experience, two main support mechanisms can be distinguished: the feed-in tariffs and its hybrid forms the feed-in premium and the green certificates[1]. **Feed-in tariffs** guarantee a fixed price for all the electricity 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. The feed-in tariff is the most used support mechanism in Europe (European Commission, 2006). A variant of feed-in tariffs is the **feed-in premium** scheme. Under this scheme, wind power producers receive the electricity market price in the one hand and in the other hand they receive a fixed premium for producing renewable energy[2]. **Green**

1 We set aside the tendering procedure that is no more applied for the moment in Europe.

2 Feed-in premium scheme is often implemented in combination with maximum and minimum total prices. If the electricity market price is higher than the fixed maximal price, wind power producers do not receive the premium. If the

certificates distinguish the selling of electricity and the environmental externalities. On the one hand, the wind power producer sell electricity produced on electricity markets. On the other hand, the wind power producers sell green certificates on a specific market. The electricity suppliers are obliged either to buy directly "green electricity" or to buy the equivalent in green certificates. The green certificates are produced each time the renewable energy source producers generate.

The following table summarizes the support schemes that have been implemented in our selected European countries.

Table 2. Support schemes in selected countries

Countries	Support schemes
Denmark	Feed-in premium + 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	Feed-in tariff for 5 years at fixed price then 15 years with decreasing tariff
France	Feed-in tariff for 10 years at fixed price then for 5 years the price depends on the load factor
Netherlands	Feed-in premium to add to the market price or reference price (SDE) since 2008 (including the market price)
UK	Renewable obligation certificate (ROC)[3] to be added to the market price

A large amount of research studies has focused on the assessment of the support schemes for the first step of renewable development. These studies frequently compare different support schemes under different criteria as effectiveness, efficiency and risk minimization (Butler and Neuhoff 2008, Del Rio, et al, 2007; Ragwitz, et al 2007; Mitchell, et al 2006). Risk minimization for investors turn out to be the most relevant criterion to assess both the effectiveness which represents the ability to reach targets and the efficiency which considers the cost of support scheme by unit of produced energy. Thus, these studies conclude that typical "low investor risk" support schemes (e.g. feed-in tariffs) are preferred than "high investor risk" support schemes (e.g. green certificates). These results can be confirmed with reality just comparing installed capacities increase and applied support schemes. The most remarkable example is Germany which applied ten years ago a feed-in tariff and which is now the leader in terms of installed capacity. Nevertheless, the "low investor risk" perspective often does not consider deeply the effects of suppressing most of the risks from the investor (Klessmann et al, 2008). This could be justified by the fact that these effects can be neglected with small quantities of wind power over the system. However, these effects cannot be neglected for large amounts of wind power.

1.2 Large-scale development of wind energy in liberalized energy markets

Wind power capacity has now entered in this new large-scale development phase and it cannot be considered as marginal. Therefore, analyses on support schemes has to be adapted and completed in order to take into account all the consequences of massive development and large amount of installed

electricity market price is below the fixed minimum price, the premium corresponds to the difference between the market price and the minimum price.

[3] Other saying, green certificates.

capacity. In that case, two phenomena - liberalization of electricity markets and integration of large-scale wind energy – imply new economic issues about adequacy between support schemes and market signals. High wind power penetrations bring to society 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[4] and other externalities costs (use of the land, landscape, etc). Nevertheless, as the wind power technology has specific generation characteristics (variability and low predictability), there are other costs induced in the power system that have to be taken into account in order to adjust adequately support schemes and electricity market designs: **the integration costs.**

1.2.1 *Integration costs of wind power and the need to include them in the analysis of efficient support schemes*

Integration costs can be separated into i) balancing costs, ii) reliability costs and iii) congestions (and losses) costs (Gross et al 2006)[5].

Additional **balancing costs** are due to the impact of wind power intermittency both on the unit commitment of the conventional power plants and on the increasing need for balancing the system[6]. 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 cost increases due to wind variability and uncertainty amount for about 1-4€/MWh depending on the observed system (Holttinen et al, 2007).

Additional **reliability costs** are associated to the weak contribution of wind power to the peak situations and to the corresponding variability of wind power generation during these periods (Holttinen et al 2007; Gross et al, 2006). 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 use of the network mostly when wind power generators are located in remote areas that are usually far from the load centers (Dena, 2005). Moving cheap electricity over larger distances can generate potentially more losses and more frequent occurrence of bottlenecks which increase losses and congestion costs. The latter cost increases because both the time lead of construction of wind plants is much low than the time required to increase the network capacity.

As the amount of intermittent generation increases in the system, integration additional integration costs become relevant and the incentives to reduce them have to be incorporated to the analysis of

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[4] The cost of support schemes corresponds to the difference between the renewable and competitive 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)

[5] Gross et al, (2006) also includes additional network connection and reinforcement costs. Additional connection and network reinforcement costs are due to the connection of a wind farm to the existing transmission and distribution grids or to the necessary upgrading of the existing lines or reinforcement of the grid. The related costs can be born either by the responsible wind farm or by other network participants. The cost allocations depend on the connection cost policy. Since these costs are not directly dependant on the market rules applied in electricity systems but on regulatory policy framework, they are not studied in this article. For a more detailed assessment of connection cost policy: (Barth, et al, 2008; Swider, et al, 2006).

[6] The balancing cost increases because the system is balanced by using additional quick start capacity and conventional power plants running at part-load .

efficient support schemes. Some new research is starting to take into account this important issue. For instance, Klessmann et al (2008) point out that from the society perspective, support schemes has to be evaluated considering two opposed factors: i) efficiency gains due to lower risk and lower required support payments and ii) efficiency losses due to reduced market response and less system optimized behavior. They conclude that more exposition to market risks of renewable would be beneficial for the total society cost if that does not dramatically increase the global risk and the support payment. Barth et al (2008) focused on the distribution of costs induced by the integration of electricity generation from renewable energy sources. This distribution depends on the support schemes, the electricity market design and the specific connection and network pricing rules applied in each country. They conclude that support schemes and market rules that give "cost-reflective" signals should contribute to an efficient integration of renewable. Based in this new research, in this article, we revisit support schemes focusing only on the assessment criterion related to the adequacy between support schemes, market design signals and incentives to control integration costs.[7]

The behaviour of individual actors and their contribution to different additional integration costs (or benefits) depend on the electricity market designs and incentives given to the market participants. For the 10 last years of electricity industry reforms, competition has been introduced in the generation part of the industrial chain[8]. Power generators compete with each other to sell electricity to consumers. In the meanwhile, support schemes have been settled to develop renewable technologies that are not yet fully competitive. Both phenomena develop concomitantly without considering consequences they can generate on each others. We firstly consider here the electricity market design and point out interactions between the chosen support scheme and incentives sent through market design.

1.2.2 *Electricity Market architecture as the key for the distribution of integration costs*

Electricity is a complex good, largely constrained by physical and technical laws for its production and transmission on the grid (Stoft, 2002). Among other, electricity cannot be economically stored and has to be produced at the same time of consumption. Thus, the introduction of competition needs the design of specific market architecture or market design (Wilson, 2002). Given the 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 the operation in real-time. Therefore, "standard" markets, where generators, intermediaries and consumers trade electricity each other are normally "forward" markets[9] i.e. they take place before the moment of delivery (Wilson, 2002). On forward markets, electricity is traded on a basis of specific sub-periods of time which could be exchanged at different horizon time. In the short run, forward energy can be traded in the day-ahead market (functioning 24 hours before delivery)[10], in intraday markets (functioning within the day) or even in real-time in the balancing market. These three sub-markets compose the sequence where economic agents can exchange electricity energy.[11].

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[7] We do not compare different support schemes under all the criteria. Therefore other issues as efficiency, effectiveness, specific design of support schemes, risk and enforcement are not studied here.

[8] Competition is also present in *retailing* activities while *transmission* and *distribution* activities are regulated given the natural monopoly characteristics (Stoft, 2002).

[9] Forward markets are financial markets that trade electricity ahead of its deliver.

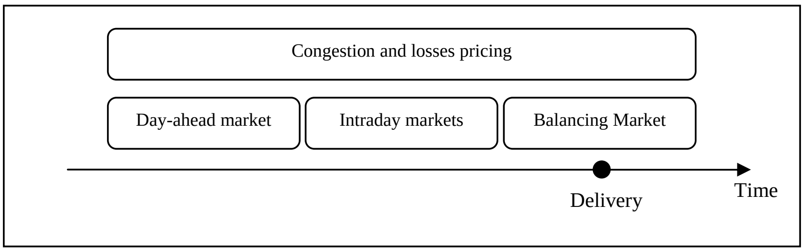
[10] Forward markets have maturities that go from 3 years to a few hours before delivery. We focus on Day-ahead market because day-ahead prices are a major benchmark for all forward trades. We do not consider futures that represent more financial and hedge products.

[11] Other services as 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). We do not focus on these services.

Other services may be defined in the market architecture in order to better represent the operation of the power system. Firstly, the use of transmission network, that is physically constrained, implies to implement market mechanisms to allocate the limited transmission capacity, to avoid congestions and to reduce losses. These mechanisms and related costs send economic signals valuing the use of this scarce resource (Ehrenmann and Smeers, 2005). Secondly, 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.

Figure 1 sums up typical electricity markets that, in a general meaning, have been organized as follows: short-term forward (day-ahead and intraday) energy markets, congestion (& losses) pricing and balancing market.

Figure 1. Electricity market Architecture.



Each of these markets or mechanism could be defined following different rules and designs and not all designs have the same economic properties concerning incentives and efficiency (Wilson 2002). This is the market design and it will determine the "quality" or "accuracy" of market signals. Table 3 summarizes the main options of market design and the implication in terms of market signals.

Table 1. Market design and market signals

	Day-ahead and intraday markets	**Balancing market**	**Congestions (and losses) pricing**
Potential market signals	Temporal differentiation of electricity	Value/cost of electricity at delivery Value of flexibility	Geographical and temporal differentiation
Market design options	-Centralization -Gate closure	-Imbalance price definition	-Nodal/zonal aggregation

The most liquid market in electricity is the day-ahead market functioning in average 24 hours before delivery. As the electricity products commercialized 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[12]. Intraday markets allow to exchange electricity from day-ahead market closure to few hours before delivery. On these markets, the degree of centralization 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

[12] 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).

centralization allows to optimize better power production given intertemporal constraints, to concentrate trades and to increase liquidity reducing transactions costs and risks (Stoft, 2002). Centralized markets have often price restrictions (e.g. price cap) limiting the electricity price to a maximum value. Another important parameter is the temporal position of the "gate closure" as it determines the closure of the forward (intraday) markets and the opening of the balancing market.

The balancing market is managed by the SO who measures the actual injections and withdrawals of energy in real-time and compares it with forward contract positions. 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). One of the most important design parameters 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 designs: a dual-price (balancing mechanism) design and a single price (real-time market) design.[13]

The goal of congestion (and losses) short-term pricing 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. Congestion (and losses) pricing is often integrated with the energy markets.[14] There are different possible designs of congestion (and losses) pricing depending on the aggregation of signals: i) nodal pricing, ii) zonal pricing and iii) redispatching.[15]

Different market designs will send different signals to the market participants and distribute the integration costs in different manners. If the market participants that can control integration costs are not exposed to proper market signals, the efficient integration of large amount of wind power can be undermined.

1.3 Adequacy between support scheme and market design

If wind power was not subsidized through support schemes, producers would have to behave on markets as producers of conventional units of production. The choice and implementation details of support mechanism have implications on the way that wind power producers participate into markets and are exposed to market signals.

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[13] The dual-price balancing mechanism design shows two different prices for negative and positive imbalances. The single-price real-time market design shows only one price for all types of imbalances. The first design is reputed to be less cost-reflective than the latter because the balancing cost of the system depends on the total net imbalance and not on individual imbalances. Hence, from this perspective individual imbalances (positive or negative) need to have the same price. Furthermore, some dual-price balancing mechanism designs add some arbitrary penalties on top of the balancing costs to compute imbalance prices, increasing in this way the difference between positive and negative imbalances prices (Vandezande et al 2008).

[14] This is called "implicit auctions" and consists in computing energy electricity prices taking into account transmission constraints and transmission losses.

[15] In one extreme, nodal pricing establishes one energy price for each node in the network. In the other extreme, redispatching gives the same price of energy no matter where this is injected in or withdrawn from the network. In the latter case, the system operator takes action to solve congestions (and minimize losses) and the costs of this action are socialized among the network users. The majority of European countries uses this last design that gives no short-term locational signal (Italy and Scandinavian countries are two exceptions using zonal pricing). 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).

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. We consider that feed-in premium and green certificates are based on the same logic of valuing the positive externality of using renewable source. For both support schemes, we analyze how wind power producer are exposed to “market” signals in the following “submarket” parts: a) forward markets (day-ahead and intraday), b) balancing markets and c) congestion (and losses) pricing.

Under feed-in tariffs scheme

- **Forward markets signals**. With the feed-in tariff, the wind power producer does not realize exchange 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 the markets; both the price and the sold volume are guaranteed for their output. This scheme reduces considerably the risk of revenue of wind power participants.
- **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 automatically (e.g. France, Germany). System-induced costs due to intermittency are generally born by the system operator then spread over network users. This reduces considerably 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.[16]
- **Congestion (and losses) pricing.** Feed-in tariff scheme isolates wind power producers of eventual locational market signals since they do not act on market to the electricity. In some implementations, 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. Portugal[17]).

Under feed-in premium and green certificates schemes

- **Forward markets signals**. Under feed-in premium or 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 premium for each kWh sold (and produced)

[16] 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).

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

that represents the value of the positive externality of the renewable use. This premium could be either a feed-in premium which means that the wind power producers receive a regulated premium or a green certificate price which is de facto more volatile. 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. [18]

- **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 (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[19].
- **Congestion (and losses) signals.** Wind power producers may have the same obligations and signals than other participants or particular rules.

Table 4. Support schemes and market signals

	Forward (day-ahead and intraday) markets	Balancing market	Short-term congestion (and losses) pricing
Feed-in tariff	No	Yes/No (possible specifics rules for wind)	No
Feed-in Premium and Green Certificates	Yes	Yes (possible specifics rules for wind)	Yes (possible specifics rules for wind)

Table 4 summarizes the main points of the interaction between support schemes and electricity markets. This table shows that different possibilities exist so that wind power producers receive market signals in the same manner than conventional power producers.

We have previously analyzed electricity market designs, support schemes and their interactions. Support schemes and electricity market designs have to be revisited and redesigned in order to promote a socially efficient integration of large amounts of wind power into the power system. On the

[18] Note that in this article, we do not focus on efficiency of different mechanisms and we do not compare them under all the criteria. The assessment criterion applied here relies solely on adequacy between support schemes and market design signals. Therefore other issues as efficiency, effectiveness, specific design of support schemes, risk and enforcement are not studied.

[19] 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%.

one hand, support schemes have to take into account system-induced costs by wind power in order to give the right level of incentives for its efficient development. This raises a first question concerning support schemes design: do wind power producers have to participate in electricity markets and do they have to be exposed to market signals? On the other hand, electricity market designs may not be adapted to accommodate large amounts of wind power and create distortions/barriers either for the wind power producer (if they are receiving market signals) or for conventional producers (if large amounts of wind power in the system increase the distortions created for non-adapted market design). This raises a second question concerning electricity market designs: are current market designs adapted to accommodate large amounts of wind power?

The paper continues as follows. Section 3 develops on the first question and section 4 develops on the second question. Our analysis is based on (Klessmann, et al 2008). They analyze pros and cons of exposing renewables to electricity market risks and make a comparison between the experiences and support frameworks of three countries: Germany, Spain and the UK. They conclude that exposing renewables more to market risks, particularly non-intermittent technologies (e.g. biomass), would be beneficial for the total society cost on condition that this does not dramatically increase the global risk and 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 responsiveness of this technology. Moreover, they do not consider explicitly electricity market design as a possible variable to better adjust market signals and to promote efficient wind power integration. We argue that this analysis has to be completed with firstly, a deeper study on the impact of market signals on intermittent technologies and secondly, a specific study of market rules and their potential distortions when badly designed.

3. Revisiting support schemes: do wind power producers have to participate in electricity markets and do they 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 and 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 are still several positive effects that can be found if one analyzes market signals and their effects more deeply.

Positive effects of exposing wind power producers to markets signals can be summarized as follows:

- **Giving signals for the selection of wind sites (based on wind 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 market signals. Note that 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.[20] Under feed-in premium or green certificates schemes, the investor will choose the 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 (Gross, et al 2006).[21]

- **Giving signals to improve maintenance planning**. Market participation of wind energy on forward and balancing markets implies higher responsiveness to price levels when implementing maintenance planning (Klessmann, et al 2008).[22] Under a feed-in tariff scheme wind power producers have the same price for the electricity produced in all hours. This scheme does not give any signals to organize optimally the maintenance. Under premium or green certificates schemes, wind power producers will select the hours when the price is low (off-peak hours) and this may contribute to the whole system efficiency.

- **Giving signals to improve 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). 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.

- **Controllability and 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 the wind mill design privileging in some way more constant and controllable generation against only a maximal output objective.

- **Transparency of the support schemes.** If wind power producers participate in electricity markets as other conventional technologies, they have to bear (a part of) the system-induced 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 system-induced costs in the support scheme allows to

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[20] 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.

[21] 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).

[22] 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.

clearly identify real costs of the subsidy for each of the proposed new technologies and to avoid cross-technology subsidies and consequent distortions. Excluding wind power producers of system-induced charges may imply excessive costs for the other market participants because extra costs are socialized (Barth, et al 2008). This could lead to an under-evaluation of the necessary subsidy for the development of wind power energy and a problem of acceptability.

- **Giving signals for the selection of wind sites (based on congestions and losses).** Wind power producers subject to locational signals should choose the wind sites that are more advantageous in terms of wind resource and in terms 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 zones may not bring high benefits if there is not enough transmission capacity to evacuate 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 incentivize investors/producers to make an arbitrage between having more congestions (and losses) costs and choosing lower wind resource sites (Barth, et al 2008).[23] This is particularly important for wind power given the strong gap between the construction lead time of wind mills and the reinforcement of transmission networks. Therefore congestions can remain for long periods.

- **Giving right signals 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, Rious, 2007) i.e. power producers are paid to reduce their production. This can happen because there is an extreme congestion (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 the wind power producers are exposed to market signals (balancing or nodal pricing), they will reduce their production in own interest and will contribute to the operation of the system. Note that under a feed-in tariff scheme, the opportunity cost for wind power producers to reduce the production is the value of the feed-in tariff (Rious, 2007) which is based on the average total cost of wind which is not related to the expected condition of the system. Under premium or green certificates schemes, the opportunity cost is mostly based on the "environmental premium" and on the expected condition of the system.

- **Improving individual forecasting.** 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). Indeed if wind power producers have to pay for imbalances, they will invest in forecast tools in order to reduce its balancing costs. Wind farm owners have the means of providing more accurate forecasts of their own production, since they know the machines' availability and could run downscaling programs with detailed information of the terrain in order to increase the

[23] Short-term locational signals have to be coordinated with long term locational signals. Locational network tariffs or cost-reflective connection costs may act in the same manner than short-term locational signals loosing accuracy but reducing the congestion (and losses) cost risk.

predictionsS' accuracy. Two conditions are needed for that these improvements on individual forecasting are translated into system balancing efficiency: that the wind power producers give good forecasting information to the System operator and that the System Operator uses all the scheduling information to reduce the cost of system balancing.

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

- **Risks of wind power producers increase.** The revenue of wind power producers that have to participate into 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 prevent the implementation of wind farms.

- **Transaction costs increase.** Participation in markets implies much 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 through the markets. The incurred transaction costs are of importance for small players. This is particularly the case for wind farms since it are usually small size plants (up to 100 MW for onshore wind farms). Nevertheless, a learning-by-doing process should lower theses transaction costs since complex operations can become kind of routines.

- **Improving aggregated forecasting.** Exposing wind power producers to balancing market signals does not necessarily reduce the overall cost of balancing in terms of better aggregated forecasting. Even if wind power producers are incentivized to improve individual forecasting, these improvements have a cost and it does not imply a more efficient outcome. Firstly, total balancing cost does not depend on individual imbalances but on total forecasting error concerning demand, conventional generation and wind power. Therefore, what a SO really needs for the balancing is the global wind prediction in its system. A detailed prediction of each farm is only really important in some special cases, for instance, when considering grid constraints violation. Secondly, the accuracy of an overall forecast is much higher than those of an individual wind farm (due to "the large numbers" effect)[24], and the improvements of each of the individual wind farms would be only marginal. In addition, actually SOs are not often using wind power scheduling information to improve operation or forecasting ability. Furthermore, the information provided by wind farms may be biased because of the economic incentives to do so. Indeed if the wind farm tries to maximize its profit, the uncertainty of the predictions should be considered, as well as an estimation of future prices and imbalance costs. Under these conditions, the most profitable "schedule" for the future settlement period, under the usual rules, is not the most accurate, but, normally, an underestimation of the production (Maupas, 2008).

[24] The large numbers effect is very important in wind forecasting. The error reduction due to the "large number effect" induces the wind farms to concentrate themselves on an only bid or schedule, or on a few ones.

From this analysis it can be seen that there exist considerable potential gains for exposing wind power producers to market signals. However increasing the exposition of wind power producers to market signals can increase the risks and transactions costs. 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, going from extreme cases of pure green certificates with any specific rules for wind power to feed-in tariffs.

4. Revisiting market designs: are current market designs adapted to accommodate large amounts of wind power?

In the last section we pointed out that wind power market participation is important to give right incentives in many aspects. A complementary issue is that current market designs are not always well-designed and market signals can be distorted. With large amounts of intermittent wind energy, distortions of signals can increase the system cost of society in two ways: i) if wind power producers are exposed to wrong signals, their reaction to signals would be inefficient and ii) if the conventional market participants are exposed to wrong signals, their reaction to signals would be inefficient as well.

4.1 Distortions on day-ahead and intraday markets

Distortions on day-ahead and intraday markets can arise mainly because of three factors: lack of coordination, price limitations (Price Cap)[25] and a gate closure too far from the real time. Firstly, the lack of coordination on day-ahead and intraday markets is related to the lack of centralization. Centralized markets concentrate trades and increase as such the coordination and liquidity of the market. Centralized markets allow the optimize generation power scheduling in longer time horizons incorporating intertemporal and network constraints.[26] It has been said that with large amounts of wind power the coordination problem of the electrical power system becomes much more complicated and more centralized designs can help to improve the coordination and the dispatch efficiency (Newbery, 2008).

Secondly, Price Caps that limit the value of electricity on critical hours create distortions for peak plants as they only recover fixed costs during a few hours during a year and need very high prices (Joskow, 2006). This distortion can increase when large amounts of wind power are present in the system. Wind power generation can be seen as a negative demand as it has near zero marginal cost. Thus its presence modifies the load-duration curve of the system which is an important element in the evaluation of the necessary peak capacity. Given wind power intermittency, the load-duration curve shape becomes sharper for peak hours, signaling the system need for more peak power plants (Allas, 2007). Price caps damp these signals for peak power plants and this can lead to the necessity of a high cost instrument to deal with high load periods (e.g. controlled rolling blackouts, etc.).

Thirdly, an issue related to the intraday market is the position of the Gate Closure. A Gate Closure that closes intraday markets far from real-time may increase the individual imbalances and the imbalance costs. The possibility of updating schedules after the day-ahead market is favorable for

[25] Note that it can exist also price cap in the balancing market and as this is the last place where market participants can sell or buy electricity, this price cap is automatically fixing the maximal prices for all the market functioning before balancing (see Stoft, 2002).

[26] 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.

wind farms, and “the shorter, the better”. Allowing market participants (especially wind power producers) to trade electricity near real-time implies that better information concerning the real amount of wind power that will be produced arrives to all the market participants (Woyte 2008; Barth, et al 2008). But the existence of intra-day market may also be redundant with the balancing markets and so lead to inefficient transactions (Maupas, 2008).

4.2 Distortions on balancing markets

Balancing signals are strongly affected by the imbalance settlement rules. Having a look of European countries, some balancing mechanisms are renowned not to be cost-reflective, meaning that imbalance prices do not reflect real balancing costs (Milborrow, 2001; ILEX, 2002; Menanteau et al 2003; Littlechild, 2007). Mostly, balancing mechanisms in different countries use a dual-price settlement system that is known not to be cost-reflective. A clear example of the lack of cost-reflective signals can be found in countries where imbalance prices are computed using artificial penalties added to imbalance costs[27].

Non-cost reflective rules distort incentives and behavior of market participants. On the one hand, very high penalties applied to imbalances may indicate to market participants that individual balancing (e.g. own back up thermal plant) is the more economic solution. On the other hand, very cheap balancing charges (lower than real balancing cost), give incentives to market participants to over-use the balancing services and this does not promote efficiency.

System balancing is highly impacted by large amounts of wind power and thus, distorted incentives can create much bigger problems than with low amounts of wind power. Although defining optimal balancing rules is not an easy task given costs allocation problems (e.g. no proper imbalance measure, non-convexities, inter-period costs and fixed costs allocation), good practice recommendations exist in literature and have to be applied in order to give proper incentives (see for instance Littlechild, 2007; Vandezande, et al. 2008).

Besides balancing market design problems, there are two other concerns with balancing that can distort balancing market signals: sensibility to market power and the lack of international integration. Balancing markets are normally very concentrated. This is mainly due to the fact that only a part of (flexible) generation capacity can participate. High concentrated markets are very sensible to market power i.e. market participants can individually increase or decrease their bid and offer in order to increase their profits. This implies higher balancing prices and distortions. One way to reduce market power in the balancing market is increasing the number of competitors. This can be done by integrating national balancing markets. Integration of balancing markets can bring several other benefits as reducing the balancing costs, improving the use of interconnections, etc.

[27] For instance, in the French market, a penalty is added to the imbalance price of those who deviate from their schedule, on condition that it is in the same way than the overall system imbalance.

4.3 Distortions on the congestion (and losses) pricing

Two main concerns of market design can create distortions in the European market: i) the lack of short term congestion (losses) signals within the countries and ii) the lack of good integrated market designs to deal with international congestions.

Most European countries do not give any short-term congestion (and losses) locational signals to the market participants (exc. Italy). Indeed, congestion and losses costs are socialized i.e. they are not charged to the responsible party but are distributed between all network users. This creates distortions in the incentives given to market participants, both wind power and conventional, increasing as such the induced-cost of wind power. First, the absence of any locational signal indicating where it is better to install wind farms and where not induces more costs to the system. This absence of signals should be compensated by supplementary investment in the network or by short-term action (redispatching) with considerable costs.[28] Second, the absence of short-term locational signals in the presence of high amounts of wind power can considerably increase the congestion (and losses) costs in general. In fact, without locational signal, conventional generators continue to schedule production without taking into account transmission network constraints (and network losses) and the System Operator has to make much more effort to control congestion (and losses) implying a higher congestion (and losses) cost. Introducing nodal/zonal pricing within countries could help to reduce these induced costs (Weigt, et al 2008; Leuthold et al, 2008). 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.

Concerning international congestion management design, European countries mainly base their international exchanges on market mechanisms based on the idea of Available Transfer Capacities (ATC). This type of mechanism is not well suited for meshed networks and to be applicable considerable security margins have to be used. This reduces the available interconnection capacities between countries and creates inefficiencies (Enhrenman and Smeers 2005). High amounts of wind power introduce more uncertainties in the power flow patterns and therefore ATC should be even more reduced in order to ensure the applicability of this method (Rious, et al 2008). Thus, badly designed international congestion management schemes imply more distortions and inefficiencies under the presence of high amounts of wind power.

Table 5 summarizes the market design concerns, distortions and consequences. It can be seen that there is considerable room to improve market design and market signals. As many of the distortions will increase with higher penetration of wind power, proper market designs are key elements in the efficient integration of large amount of wind power.

[28] "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. In other 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.

Supprimé :

Table 5. Support schemes and market signals

	Market design creating distortions	Consequences
Day-ahead and intraday markets	-Lack of centralization (coordination) -Price cap too low (and no other mechanism to compensate) -Gate closure far from real time	- Increase in the unit commitment costs -Increase in the reliability cost and in problem of adequacy -Penalizing intermittent technologies
Balancing markets	-Non-cost reflective imbalance price rules -Lack of integration	-Promote expensive solution to balance (own back up reserves) -Increase in the balancing problem and sensibility to market power
Short-term congestion (losses) pricing	-Lack of short-term location signals -Lack of good market design for international congestion management	-Increase in congestion (and losses) costs -Reduction of interconnection capacity and increase in international congestion costs

5. 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.

It is clear 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. The weight of each of these effects has still to be evaluated quantitatively in order to derive detailed policies recommendations. But at this moment one can know the direction of the policy adjustments.

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. There exist several options concerning support schemes to expose more wind power producers to market signals. These options yield between two extremes: green certificates and the feed-in tariff. Feed-in premiums and tariffs with balancing responsibility can have better results than simple feed-in tariffs. A premium seems to be a good 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.

Support schemes have to take into account “extra” costs coming from the participation in markets. Market design rules are common and apply to all producers whatever their production technology. But some of these technologies such as wind power may bear extra costs due to their intermittency. In that case the support scheme may recover these costs. The support schemes have to include some “normal/efficient” subsidy for system-induced costs (balancing, congestions, etc.). This allows wind power producers to participate in the market, to face with system-induced costs (that they are causing) but without stopping development. Including system-induced costs in support schemes allows to clearly identify real costs of the subsidy for each of the proposed new technologies and to avoid cross-technology subsidies coming from distorting asymmetrical market rules. Moreover, including system-induced costs in support schemes allow also market participants to prepare themselves to participate into the electricity market considering that in the future the subsidize mechanism will probably disappear. 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 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 system-induced cost. In this case, participants with better than normal/efficient behavior earn extra profit and participants having worse results than normal/efficient have a loss.

Market rules have to be settled properly in order to be cost-reflective and to give right incentives to all market participants. As market rules will define the revenue that a wind power producer earns, bad market rules can create distortions in incentives and these can increase in the presence of large-scale wind energy. Good rules are not only important for wind power but also to not distort the behavior of conventional generation under the presence of huge quantities of wind power. It can be the case that bad rules that does not have high consequences on conventional generation before the development of large amounts of intermittent renewables, start to be quite relevant with much afterwards and distort the system. This could be the case for balancing costs and redispatching (or congestion) costs.

The increase in market risks due to exposing wind power producers to market signals can imply a more costly implementation and some loss in effectiveness. Specific rules for wind power can “mild” the impact of market signals on the increase of risks and can be used to make the fine tuning of the promotion policies. Tolerances in imbalance and fixed maximal prices are an example of this.

Finally, a regulatory framework has to be settled to give incentives to the System Operator in order to improve “centralized activities”, i.e. wind power forecasting, balancing the system and congestion management. For instance, as balancing charges do not give enough incentives to promote a system efficient forecasting, the SO is responsible of centralized forecasting and has to be incentivized to realize this task efficiently.

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