Pros and cons of exposing renewables to electricity market risks—
A comparison of the market integration approaches in Germany, Spain,
and the UK

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A B S T R A C T
The article examines how renewable electricity (RES-E) producers are integrated into the electricity market under the support legislations and regulatory frameworks of Germany, Spain, and the UK. Focus is on wind power, which faces the highest market integration challenge of all RES-E. The analysis shows that the three countries follow contrasting approaches of exposing RES-E producers to the market risks of forward electricity markets, balancing markets and system planning requirements. Risk exposure is highest in the UK and lowest in Germany. From a policy maker’s perspective, there is a trade-off between a “high risk” and a “low risk” approach. When RES-E face high market risks, a higher level of financial support is required to stimulate RES-E development than in a low risk environment, but the exposure to market risks may also give an incentive to make efficient use of the respective market, thus limiting the indirect costs to society. The special characteristics of wind energy, however, put natural limits to the response of wind power plants to market prices and locational price signals and will increasingly influence electricity markets and grid infrastructure. These interdependencies should be recognised in the design of RES-E policies and market regulations.

1. Introduction

This article focuses on the interaction between support policies and electricity market designs. It examines how renewable electricity producers participate in the electricity markets of Germany, Spain, and the UK, and how these markets are influenced by renewable electricity (RES-E) integration, respectively. Based on this analysis, pros and cons of exposing renewable generators to market risks will be discussed.

Many policy analyses mainly compare RES-E support policies as such, especially focusing on the most common support instruments: feed-in tariffs and quota systems, to a lesser extent also tenders and financial incentives (e.g., Ragwitz et al., 2006, 2007; Mitchell et al., 2006; Morthorst et al., 2005). Ragwitz et al. (2007) have analysed the effectiveness and efficiency of support instruments for RES-E in different European countries. They come to the conclusion that the success of RES-E support policies is strongly influenced by electricity-grid- and electricity-market-related barriers. In other words, the success of renewable energy deployment does not only depend on the design of the support policies but also on the electricity market design and the interaction of both fields of regulation.

In the political discussion about RES-E support schemes in Europe, the market integration and participation of RES-E is a controversial issue. Advocates of liberal market concepts favour “market-based” support schemes (usually meaning quota systems) to provide competition and least-cost RES-E (e.g., Eur- Electric, 2003). Opponents argue that renewable energy support should not be market based as long as European electricity markets are not fully unbundled and competitive (e.g., EREC, 2005). It is important to recognise that the term “market” is used in an ambiguous way, sometimes referring to the support mechanism, sometimes referring to the electricity market participation. As a matter of fact RES-E always influence and in some way participate in electricity markets. We will discuss the way RES-E are involved in several types of electricity markets and identify the specific chances and challenges of market integration. This article will distinguish the participation in the following markets:

- **Forward electricity markets**: Trade of RES-E ahead of delivery, via bilateral contracts or on the power exchange. We will focus on the day-ahead market. Since day-ahead market prices are a
major benchmark for all forward trades, the day-ahead market is of special significance for electricity price assessments. 

- **Balancing markets**: Participation of RES-E in imbalance settlement and balancing services markets.
- **Support markets**: Trade of RES-E on special tradable green certificate (TGC) markets, most relevant under a RE quota obligation. The most prominent example of a TGC market is the British Renewable Obligation Certificate (ROC) market. TGC markets have been analysed extensively, e.g. by Bertoldi and Huld (2006) and Midttun et al. (2005), and will only be shortly touched upon here.

While green certificate markets only trade the green value of energy, the other mentioned markets are submarkets of the power market that overlap and interact. A precondition for power market participation is the physical integration of RES-E into the electricity network. For this reason, aspects of grid access and system planning will also be considered.

The article will examine how renewables are integrated into these electricity submarkets operationally and economically under different RES-E support legislations and discuss the pros and cons of assigning market responsibilities and risks to RES-E generators.

Section 2 introduces general electricity market architecture and principles of power system operation. Section 3 summarises basic influences of RES-E deployment on those markets, independent of specific country cases or support schemes. Section 4 will examine the electricity market integration of RES-E in three countries, representing the three most prominent RES-E support schemes in Europe:

- A *quota* scheme, represented by the UK “Renewables Obligation” (RO, 2002).

For those three case studies, five questions will be analysed that reflect on the economic and operational integration of RES-E into the electricity markets:

1. **Economic integration into forward markets**: How do forward electricity market prices affect the RES-E generator’s revenues under these support schemes?
2. **Operational integration into forward markets**: How is the renewable electricity integrated into the electricity market?
3. **Operational integration into balancing markets**: Who is responsible for the forecasting and balancing of the RES-E production?
4. **Grid integration**: What are the regulations for grid access and who pays for RES-E-related grid reinforcements?
5. **Effect of RES-E on electricity markets**: What is the effect of RES-E on electricity market prices and is this effect relevant for RES-E producers?

Section 5 will compare the market integration approaches of the three countries and discuss the pros and cons of exposing RES-E generators to specific market risks. This will be examined from two perspectives:

- the implication for the RES-E generator and
- the implication for overall societal costs.

Based on this discussion, conclusions and policy recommendation for the market integration of RES-E will be drawn (Section 6).

### 2. Introduction to power market architecture and basic principles of power system operation

This section gives a short overview of the basic power market architecture and operation.

#### 2.1. Power system operation as precondition of electricity trade and delivery

Electricity poses a special challenge to market design; it is a product that can only to a very limited extent be stored in a commercially viable way. The power system can only function in a stable manner if supply and demand are continuously balanced. Since the demand of electricity is highly inelastic, the balance has to be achieved mainly on the supply side (de Vries and Hakvoort, 2003). In every electricity market, a system operator ensures reliable system operation by purchasing and dispatching reserve power to provide the balancing services. Since the System Operator has a monopoly in this function, it is always regulated by the State. Through this regulation, governments have the possibility to significantly influence the electricity market.

#### 2.2. Forward markets

Forward markets are financial markets that trade electricity ahead of its delivery. Trading periods reach from years ahead until hours ahead. Most prominent when speaking about electricity markets are day-ahead markets. Intraday markets have been introduced only recently to some European countries and are closely linked to balancing markets. A customer who buys electricity in a forward market will receive either electricity delivered by the seller or financial compensation (Stoft, 2002).

Within forward markets, electricity can be traded via bilateral contracts (“over the counter contracts”, OTC), or as standardised products at a power exchange. Power exchanges usually offer platforms for long-term trade (futures market) and short-term trade (spot market).

Day-ahead spot market prices are a major benchmark for all forward trades.

For stochastic RES-E like wind energy, short-term markets (day-ahead and intraday) are of special relevance, because their output cannot be predicted far in advance.

#### 2.3. Balancing markets

The balancing market (also called real-time market) is a physical market, as all trades correspond to actual power flows. Any power that is sold in the day-ahead market but not delivered in real time is sold in the day-ahead market but not delivered in real time

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1. The term spot market implies that commodities are bought and sold for cash and delivered immediately. While Stoft (2002) uses the term only for the real-time market, it is frequently used to include the day-ahead and intraday markets. We will use the latter terminology, since the spot markets of most European power exchanges are day-ahead markets.
is deemed to be purchased in the balancing market from the system operator at the imbalance energy price (two-settlement system, see Stoft, 2002). The system operator buys the required balancing energy/capacity on special balancing service markets. The balancing procedure can be described from two perspectives:

- The use of balancing services for the imbalance settlement.
- The provision of balancing services on balancing service markets.

Fig. 1 depicts the basic transactions.

2.4. Use of balancing services (imbalance settlement)

Balancing responsible parties are generally all generators or traders of electricity. They are required to submit day-ahead schedules to the system operator that estimate their electricity feed-in or consumption. Schedules can be modified before gate closure, which is generally 1–3 h before real-time delivery. The obligation to deliver schedules is attached to the financial responsibility for any deviation from the schedule in actual delivery or consumption. The imbalance settlement rules define the way how deviations are priced, i.e. how prices of the balancing service markets are transformed to imbalance prices for the users of balancing services. According to these rules, balancing responsible parties receive payments or have to pay for the imbalance volume of energy. There are two principle pricing options:

- Single imbalance pricing where a single imbalance price is used independently whether the imbalance is positive or negative.
- Dual imbalance pricing where a different price is applied to positive imbalance volumes and negative imbalance volumes.

The settlement of the imbalance volume is done by the system operator subsequent to the actual delivery. Dual imbalance pricing gives a stronger incentive to deliver correct schedules than single imbalance pricing, since generators that do not deliver the scheduled energy face higher imbalance charges. Strategic gaming (e.g. scheduling less production than actual delivery), however, also occurs.

2.5. Balancing service markets

Balancing services are used by power system operators to match real-time electricity demand and supply and guarantee a constant network frequency. The balancing services (energy and/or reserve capacity) are sold daily on special balancing service markets by parties who are able to provide them. These are mostly generators, or to a lesser extent, large consumers. Different balancing service categories are distinguished according to the time horizon that needs to be balanced: primary reserve (seconds ahead), secondary reserve (minutes ahead), replacement reserve (hours ahead). The economic value of these services decreases in the same order. The balancing of wind power mainly requires relatively cheap replacement reserve.

A great variety of market designs exist with respect to pre-qualification requirements, bid evaluation and settlement rules of balancing service markets. The market’s competitiveness is crucial for the pricing of schedule deviations, since the pricing for imbalance energy is determined by market results of the balancing service market.

3. Principle influence of RES-E on the power market

3.1. Principle influence of RES-E on the dispatch of power plants and on spot market prices

Power plants are generally dispatched in such a way that the lowest possible costs of produced electricity are attained at each moment. Therefore power plants with the lowest variable production costs are put into operation first (Blok, 2006). There are practical deviations from this order, however, because fossil power plants (especially coal, lignite and nuclear) are limited in their operational flexibility. A certain share of the generation also

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2 In some market designs, e.g. Spain, there is a market operator that is in charge of imbalance settlement.
has to be provided by synchronous generators that establish the system frequency.

Most renewable energy technologies are characterised by high capital costs and low fuel and operational costs. This is especially true for intermittent renewables (wind, solar, hydro) that have zero fuel costs. For this reason they come first in the merit order of power plant dispatch.\textsuperscript{3} The deployment of RES-E thus changes the structure of power supply and decreases marginal prices, due to the increased supply at low variable costs (see Morthorst, 2007). For peak hours, the spot price difference between times of high wind feed-in (as a function of MW system load, see Morthorst, 2007) with practically no wind (blue line) and on days with medium or some countries, notably Denmark, Spain, and Germany. Fig. 3 shows the spot market price curves for Western Denmark on a winter day with practically no wind (blue line) and on days with medium or high wind feed-in (as a function of MW system load, see Morthorst, 2007). For peak hours, the spot price difference between times of high and low wind feed-in is in the order of 30\(\text{€}/\text{MWh}\) (and even higher for system loads >1000MW). Morthorst estimates that wind power feed-in decreased the average spot market price in 2005 by almost 14%. The magnitude of the effect can be explained with the high wind power penetration in Denmark. Wind power covers approximately 25% of total power consumption in Western Denmark. The installed wind power capacity (2400MW) is about one third of the total installed power plant capacity.

In the long term, there is another side effect of increased wind power feed-in that might influence market and consumer prices. Because renewables are employed first in the merit order of power dispatch, the commissioning and the market revenues of fossil fuel plants will decrease. On a long-term scale, decreased revenues may lead to lower new capacity investments or even de-investments (see Nabe, 2006; Wissen and Nicolosi, 2007). At times of low or no wind power availability, this reduced capacity could then facilitate increased spot prices for fossil fuel plants.

There are further direct and indirect effects of renewables deployment on electricity wholesale prices, e.g.

- Decrease of \(\text{CO}_2\) allowance prices (Rathmann, 2007).
- Hedging of fuel price risk (Awerbuch and Sauter, 2006; Wiser and Bolinger, 2004).

\textsuperscript{3} If a regulated priority for the feed-in of RES-E (e.g. like in Germany) exists, all renewables—including bioenergies, which have higher fuel costs—are dispatched before fossil power plants.

- Shift in the structure of the conventional power plant mix in the direction of more flexible power stations with lower capital costs and higher fuel costs (DENA, 2005).

A complex cost analysis would be required to estimate the net macroeconomic effect of these different influences on wholesale market and consumer prices. In the following sections we will concentrate on the decreasing effect on spot market prices described above. This short-term effect is highlighted as it directly affects the market revenues of wind power producers, if they are exposed to market prices: whenever their wind yields are high, their market revenues are lower than average market prices.

### 3.2. Principle influence of RES-E influence on balancing requirements and regulation costs

Non-intermittent RES-E only require the conventional balancing provisions. They are as predictable as any conventional power generator, if the employed technology is reliable.

Intermittent RES-E that are characterised by limited predictability (especially wind energy) influence the dispatch of conventional generators in the system. They usually increase the total dispatch cost of conventional generation, since they needed to be combined with flexible power plants that usually have higher variable costs than inflexible power plants. Through this combination, their stochastic load profile is integrated in the conventional plant dispatch to meet the demand load profile. Only part of this transformation is done with the service of balancing markets; most of it can already be settled day-ahead. The better the intermittency of RES-E can be integrated into generation dispatch, the lower the remaining balancing demand and costs. A way of achieving this is to reduce the forecast error for RES-E production. In this context, intraday markets can play an important role, since they open the opportunity to adjust schedules to improved forecasts on the day of delivery. Such adjustments are of special importance for wind energy. For example, if wind power plants are concentrated in one area (e.g. the North Sea coast in Germany), their prediction errors are correlated. Sudden drops in wind speed will increase the system imbalance in the same direction. At high wind capacity shares in total system load, this can lead to high overall imbalance volumes and costs.

Several studies have demonstrated that an increasing share of wind energy in system load results in higher balancing costs (IEA, 2007, 2005; DENA, 2005). According to the studies compared in Holttinen et al. (2007) and IEA (2007), at wind penetrations of up to 20% of gross energy demand, system operating cost increases arising from wind variability and uncertainty amount...
to about 1–4 €/MWh. The designation of these costs, however, depends on the characteristics of the given electricity system and market (Verhaegen et al., 2006). Due to this complexity, we will not analyse this aspect in the country case studies.

4. Electricity market integration of RES-E under different support schemes—the country cases Germany, Spain, and the UK

This section will examine how renewable electricity is economically and operationally integrated into the electricity markets of Germany, Spain, and the UK, focusing on the role of each country’s main RES-E support policy in the integration process. The examined support policies represent the three predominant support schemes in Europe:

- **Feed-in tariffs** (Germany) — RES-E generators sell their produced electricity at a legally regulated price per kWh to the electricity suppliers.
- **Feed-in premiums** (Spain) — RES-E generators sell their produced electricity on the electricity markets and receive a fixed bonus payment (premium) per kWh on top of the electricity price.
- **Quota obligation based on tradable green certificates** (UK) — RES-E generators sell their produced electricity on the electricity markets and the “green value” of their production on special green certificate markets. The demand for green certificates is created by quota obligations for electricity suppliers.

4.1. Market integration under the German feed-in tariff scheme

Germany has implemented a feed-in tariff scheme since 1991. The first scheme provided one single tariff for all RES-E technologies and led to considerable wind energy development. Rapid market growth also for other RES-E technologies occurred after the Renewables Energy Sources Act (“Erneuerbare Energien Gesetz”) was introduced in 2000. This legislation guarantees priority feed-in and fixed feed-in tariffs for each renewable energy technology. The first scheme provided one single tariff for all RES-E technologies. Successive amendments in 2004, 2008, and 2012 introduced further differentiation and degression rates.

### 4.1.1. How do electricity market prices influence the RES-E generators revenues?

Under a fixed feed-in tariff regime, RES-E generators do not financially participate in the electricity market. They sell their electricity at a guaranteed price; therefore electricity market prices are not relevant for them. Theoretically, RES-E generators are free to sell energy on the market, directly to end-users or via traders or the power exchange.

### 4.1.2. How is the renewable electricity integrated into the electricity market?

Even though RES-E generators are not confronted with the rules and risks of the electricity market, the electricity sold under the feed-in tariff regime is still integrated into the market. The main responsibility is taken by the TSO.

The Distribution Network Operators transfer the electricity for the fixed price to the respective TSO (Germany has four TSOs), which transforms the load fluctuating profiles to a standard load profile. The transformed standard load profiles are sold to all utilities that deliver electricity to final consumers. The utilities charge the average tariff to their customers.

The financial implications of the transformation process from the fluctuating load profile into a fixed profile are supervised by the regulator (“Bundesnetzagentur”). The transformation costs are passed on to the network customers and are included in the Use of System Charges (UoSCh).

The profile transformation mechanism is not fully transparent. The German TSOs are not only responsible for system operation but also assume trading functions by predicting RES-E production and trading electricity for the profile transformation (see BET, 2004). Since the costs of the profile transformation are passed on to the network customers, there is no systematic incentive to minimise these costs. The German TSOs claim to perform the transformation under market conditions. This practice has, however, been challenged by the German regulator, who indicated in summer 2006 that the transformation costs of several TSOs were too high. This finding was underpinned by a study by LBD (2007) that found that the average transformation costs for RES-E of 8.3 €/MWhRES-E declared by the TSOs for 2006 were considerably higher than the costs of 3.4–5.4 €/MWhRES-E that resulted from their own cost assessment. One option to increase transparency of transformation costs would be a public call for tenders to purchase these services or to increase regulatory oversight of this process.

It can be concluded that the transparent and not cost-optimised transformation mechanism is one major weakness of the German feed-in tariff system.

### 4.1.3. Who is responsible for the forecasting and balancing of the RES-E production?

All RES-E generators that sell their electricity under the feed-in tariff scheme are exempted from the balancing responsibility.

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Table 1

<table>
<thead>
<tr>
<th>Technology</th>
<th>Feed-in tariff 2007 (€/MWh)</th>
<th>Degression</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind onshore</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Initial tariff (year 1–T)</td>
<td>81.9</td>
<td>2%/a</td>
</tr>
<tr>
<td>Base tariff (year T=20)</td>
<td>51.7</td>
<td></td>
</tr>
</tbody>
</table>

* T depends on yield of wind power plant.
they neither have to deliver generation schedules nor carry balancing costs. Forecasting, scheduling and balancing are done by the TSO. In principle, because of the high number of wind power plants supervised by one TSO, this central approach allows high forecasting precision as opposed to decentralised forecasting. On the other hand, the TSOs are not forced to minimise the forecast error and thus the balancing cost for RES-E, since they can pass them via the UoSC to the customers.

A structural problem of the German balancing service market is its low liquidity and thus relatively high price level. If RES-E generators were balancing responsible, they would thus be confronted with relatively high balancing costs.

4.1.4. What are the regulations for grid access and who pays for RES-E-related grid reinforcements?

The Renewable Energy Sources Act guarantees grid access of renewable energy plants. The RES-E plant operator only pays for the connection to the nearest grid connection point (low or medium voltage level). If the distribution or transmission grid has not enough capacity to transport the generated electricity, the network operator is obliged to reinforce the grid. The costs can be charged to the consumers via the UoSC. In practice, the required transmission grid reinforcement advances very slowly. This is mainly due to the long permitting procedures for transmission grid construction.

As long as the network reinforcement has not been accomplished, RES-E plants in Germany can connect to the grid under the “congestion management” arrangement of the Renewable Energy Sources Act. According to this clause the network operator is allowed to curtail the output of RES-E plants if the network is already congested with electricity from other RES-E plants. Newly installed plants need to be equipped with technical provisions for such curtailment. This arrangement was introduced in 2004 to bridge the time gap until transmission and distribution networks are reinforced by the network operators. According to the law, the plants that have been connected to the network last will be cut off first, but for practical reasons, usually all plants that fall under the arrangement are curtailed to the same output rate. In regions with high RES-E penetration and weak grid infrastructure (especially northern Germany), such congestion management on distribution and transmission level poses an increasing risk to the RES-E generator. The curtailment results in a loss of feed-in tariff revenues to the RES-E project. In the most affected region in Northern Germany, the curtailment of wind power plants amounted to approximately 5% of their annual yield in 2005, with increasing tendency (Jarass and Obermair, 2005). The insecurity introduced by the fact that the rate of curtailment is difficult to predict for RES-E operators might be considered more significant than the actual losses of income. Hence, the revised feed-in-law foresees that generators will be compensated for their losses from 2009 onwards.

4.1.5. Is the effect of intermittent RES-E on electricity market prices relevant for RES-E producers?

Neubarth et al. (2006) show that spot market prices at the European Energy Exchange in Leipzig, Germany, were lower than average on days with high predicted wind power feed-in in the 12 months period between September 2004 and August 2005. They find a weak but robust correlation, and estimate an average spot market price reduction of 1.89 €/MWh for every 1000 MW forecasted wind power. The overall spot market price reduction in Germany is estimated at 2.7 €/MWh for the 12 month period. Diekmann et al. (2007) estimate the spot market price reduction of RES-E for the following years:

- 3–4 €/MWh in 2005 and
- 6–8 €/MWh in 2006.

For comparison: The RES-E share in total electricity consumption was 10.4% in 2005 and 12.0% in 2006 (BMU, 2007).

The price decreasing effect is not relevant for RES-E producers, since they are paid fixed feed-in rates. It is relevant for the TSO, however, that trades parts of this electricity day-ahead on the spot market or via OTC contracts and will be affected by the reduced market price. The price spread between days with high and low wind feed-in translates to additional costs for the profile transformation by the TSO and will be passed to its customers via the UoSC (Neubarth et al., 2006).

4.2. Market integration under the Spanish feed-in premium scheme

The Spanish feed-in premium scheme was introduced in 1998. It was amended by the Royal Decree 436/2004 in March 2004 and Royal Decree 6 61/2007 in May 2007. RES-E generators are granted priority grid access and priority feed-in. Financially, they can choose between two remuneration options:

a. a technology-specific fixed feed-in tariff and
b. a technology-specific feed-in premium on top of the electricity market price (“market option”): electricity market price+premium (+ “incentive”, only before 2007).

The first option is more or less analogous to the feed-in tariff scheme in Germany. In the second option, the RES-E generator sells the produced electricity on the electricity market via bilateral contracts or the power exchange. On top of the price achieved on the market, a technology-specific premium is guaranteed by law. Before 2007, this premium was paid independent of the market price. After electricity market prices increased significantly in 2004–2006 and resulted in high revenues for wind power projects, RD 661/2007 introduced upper and lower boundaries for the RES-E generator’s revenues (i.e. it grants a minimum tariff independent of the market price, and limits the maximum value of market price plus premium). The premium option is still the preferred scheme for wind power operators. About 97% of wind parks were using this remuneration option in 2007 (Ceña, 2007a). Table 2 gives an overview of the tariffs and premiums for wind onshore. Market prices, premiums, and actual market revenues in the first 9 months of 2007 are shown in Fig. 4.

RES-E generators can switch between the fixed tariff and the premium option every 12 month, as many times as they like. The costs of the premium and the additional costs of the fixed tariff are passed on to the electricity consumers via the electricity distributor and the regulator CNE.

The Spanish support scheme has been effective in promoting RES-E development, mainly in the wind energy sector. The installed wind power capacity increased from 839 MW in 1998 to 15,145 MW in 2007 (AEE, 2008).

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5 The network operators argue that the density of RES-E installations varies substantially across the country and so does the increase of charges in their area. In contrast to the feed-in tariff costs, no mutual compensation between network companies applies to grid reinforcement costs.

6 The price decreasing effect is not relevant for RES-E producers, since they are paid fixed feed-in rates. It is relevant for the TSO, however, that trades parts of this electricity day-ahead on the spot market or via OTC contracts and will be affected by the reduced market price. The price spread between days with high and low wind feed-in translates to additional costs for the profile transformation by the TSO and will be passed to its customers via the UoSC (Neubarth et al., 2006).

7 For a detailed assessment of the spot price effect, see also Sensfuss (2008).
Wind onshore tariff scheme. Transformation to base load profiles as under the German feed-in tariff regime, directly transformed to the demand load profile. There is no direct sale to its customers. Thus, the produced electricity is regulated by the utility, integrated into its portfolio, and sold for profit for their trading services. Such intermediaries can achieve better prices than RES-E operators would do on their own, but will keep part of the sales profit for their trading services. Smaller RES-E generators close power purchase agreements (PPAs) with intermediaries (utilities or independent traders) that trade the electricity on the market. Wind premiums and market revenues 2007 in €/MWh (Ceña, 2007b).

### 4.2.1. How do electricity market prices influence the RES-E generators’ revenues?

Under the premium regime, electricity market prices are an integral part of the RES-E generators’ revenues. They sell the renewable electricity on the electricity market and receive a premium payment on top of the achieved price, but market risk and profit margin have been limited by the upper and lower boundary tariffs introduced within the RD 661/2007.

Under the feed-in tariff regime, RES-E generators are not exposed to market prices.

### 4.2.2. How is the renewable electricity integrated into the electricity market?

No special regulation is needed to integrate renewable electricity under the premium option. RES-E generators can sell their electricity on the day-ahead market or via bilateral contracts like any other electricity producer. The Spanish wind power market is dominated by large utilities that also act as wind power operators (Iberdrola, Union Fenosa, etc.). These utilities can easily integrate the produced RES-E into their portfolio and sell it directly to their clients. Smaller RES-E generators close power purchase agreements (PPAs) with intermediaries (utilities or independent traders) that trade the electricity on the market. Such intermediaries can achieve better prices than RES-E operators would do on their own, but will keep part of the sales profit for their trading services.

Under the fixed feed-in tariff option, the RES-E is bought at the regulated price by the utility, integrated into its portfolio, and directly sold to its customers. Thus, the produced electricity is directly transformed to the demand load profile. There is no transformation to base load profiles as under the German feed-in tariff scheme.

### 4.2.3. Who is responsible for the forecasting and balancing of the RES-E production?

In Spain, the balancing responsibility of RES-E generators depends on the choice of the support option.

Under the fixed feed-in tariff option, RES-E generators are only partly responsible. Wind farms and other RES-E with a capacity > 10 MW must predict their daily schedule 30 h before the start of the day. Imbalance prices are fixed at 7.8 €/MWh. 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%, for other renewables 5% (i.e. if delivery deviates more than 20% from the scheduled volume, 7.8 €/MWh have to be paid for the deviation > 20%). According to Ceña (2007a), these balancing charges result in average costs of 1.5 €/MWh wind power production under the fixed feed-in tariff option. Since the RES-E production under this option is integrated into the large portfolio of the distributor, who can adjust the schedule during the day, the actual imbalance costs are assumed to be even lower.

Under the premium option, RES-E generators are fully responsible for balancing and have to deliver schedules like any other market participant. Independent wind power producers usually make arrangements with intermediaries that accumulate generators under their contract and schedule the electricity production. This increases prediction accuracy. Spain has a well-established and liquid intraday market with six intraday trading periods that can be used to minimise the costs of schedule deviations.

Imbalance prices that apply for schedule deviations are fluctuating with hourly market prices, but upper limits are set by the regulator (for all electricity producers, not just for wind: Ceña, 2007a). Imbalance prices are high for schedule deviations that enhance the total system imbalance and zero for those that reduce it (dual imbalance pricing). Average imbalance costs for wind power plants under the premium option are estimated at 2.6 €/MWh for 2006 and 1.4 €/MWh for 2007 (Ceña, 2007c).

### 4.2.4. What are the regulations for grid access and who pays for RES-E-related grid reinforcements?

Grid access for RES-E is guaranteed and regulated by several royal decrees. If the distribution or transmission grids need to be reinforced due to the connection of the RES-E plant, the plant operator has to carry the full costs on distribution level and a negotiable part of the reinforcement costs on transmission level. Negotiations about the costs to be carried by the project developer in case of reinforcement are a major obstacle in the grid connection process.

Costs for transmission grid reinforcement usually cannot be clearly attributed to the connection of RES-E since electricity demand increases and the necessity of network reinforcement exists also without RES-E integration. The network operator Red Eléctrica therefore carries the major share of the costs of transmission grid reinforcement. Nevertheless, a certain share of typically 20% is assigned to the involved RES-E plant operators. This share is established with the connection offer.
Grid congestion and curtailment are a serious problem in Spain, both on the 220 kV level and in some distribution networks. Electricity demand and generation capacity are growing rapidly, while network reinforcement advances slowly.

4.2.5. Is the effect of intermittent RES-E on electricity market prices relevant for RES-E producers?

In 2007, wind power had a decreasing effect on spot market prices in the order of 2–3 €/MWh for every 1000 MW of wind power in the system. This amounted to a price decrease of approximately 20 €/MWh in times of high wind feed-in (7000 MW system load),\(^8\) as depicted in Fig. 5 (Cen˜a, 2007c). The lower than average spot market prices directly affect the revenues of the wind power producers, but the price risk is limited by the minimum tariff for market price plus premium introduced under the RD 661/2007.

4.3. Market integration under the British quota obligation

The renewables obligation (RO) was introduced in England, Wales, and Scotland in April 2002, and in Northern Ireland in April 2005. The RO requires electricity suppliers to supply an increasing percentage of electricity from renewable energy sources. The 2006/2007 target was 6.7% (2.6% in Northern Ireland) rising to 15.4% by 2015/2016 and remaining at least at this level until 2027 (RO, 2002).

Suppliers meet their obligations by presenting ROCs (1 ROC = 1 MWh). ROCs are issued by the regulator Ofgem for all domestic RES-E generation. All renewables are treated the same (with the exemption of large hydro that is not eligible), thus favouring least-cost RES-E technologies. From 2009 it is intended to “band” the RO to award more or less than one ROC per MWh depending on the technology type (Energy Bill, 2008).

If suppliers do not have sufficient ROCs to cover their obligation, they must pay a penalty per MWh into a buy-out fund. The buy-out price is adjusted annually in line with retail price index. The buy-out fund is recycled annually to electricity suppliers in proportion to the number of ROCs they surrendered in the compliance period. Market players, which have met their obligation gain extra revenues, at the expense of those who did not meet their obligation. This buy-out recycling mechanism gives suppliers an extra incentive to hold ROCs and has kept the ROC market price above the buy-out price, because the ROC’s value for the electricity supplier equals the buy-out price plus the recycle payment. Table 3 provides an overview of RO targets, buy-out price, recycle, and market prices. The annual expenditure of the RO is paid by the electricity customers. It is kept constant through the definition of the buy-out price.

Independent RES-E producers can sell their ROCs directly to traders or suppliers via purchase agreements, or sell them at the quarterly auctions of the Non-Fossil Purchasing Agency (NFPA). Since the introduction of the Renewables Obligation in 2002, the ROC’s price at the quarterly auctions has fluctuated between £38 (lowest value in January 2006) and £52 (highest value in July 2004). In the January 2008 auction, just less than 65,000 ROCs were purchased at an average price of £49.95 (~72.43 €/MWh, see NFPA, 2008). Wholesale electricity prices were in the order of 40–50 €/MWh.

So far, the Renewables Obligation has not delivered the envisaged target share. The British RES-E share increased from 1.7% in 1997 to only 4.1% in 2005 (European Commission, 2006), compared to a target of 5.5% in 2005–2006. Total installed wind power capacity amounted to 2400 MW in 2007 (BWEA, 2008).

4.3.1. How do electricity market prices influence the RES-E generators’ revenues?

In terms of reflecting electricity market developments, a quota scheme has common properties with a feed-in premium scheme. The RES-E generators sell the generated electricity on the market, and the obtained price is an integral part of their revenues. The essential difference is that the revenues from the electricity market are not supplemented by a fixed premium, but by the ROCs revenues. Since the price on the ROCs market is fluctuating and not correlated to the electricity market price, the RES-E generator has to deal with the uncertainties of two independent markets, i.e. the forward electricity market and the TGC market.

4.3.2. How is the renewable electricity integrated into the electricity market?

No special mechanism is needed to integrate the renewable electricity into the electricity market. RES-E generators can sell their electricity on the electricity markets. Independent RES-E producers may close power purchase agreements with utilities or other intermediaries who integrate the electricity into their portfolio.

4.3.3. Who is responsible for the forecasting and balancing of the RES-E production?

In the UK, RES-E operators have full balancing responsibility. In most cases, electricity suppliers act as intermediary and balancing responsible parties. Settlement prices for deviations depend on the total imbalance of the transmission system as well as on the direction of the individual scheduling deviation (dual imbalance pricing):

- If the balancing responsible party increases the system imbalance, imbalance prices are derived from the balancing service market price. In this case, system-buy and system-sell prices are very volatile and sometimes take values tens of times larger than their average (Angarita-Márquez et al., 2007), e.g. up to 200 €/MWh on 18 December 2007 (Elexon, 2008). This price mechanism therefore means a high risk for wind energy projects, especially if the prediction was higher than the actual generation.
- If system imbalance and individual deviations have opposite directions (i.e. they neutralise each other), system-buy and system-sell prices are based on market prices from short-term energy trades. These prices are usually lower than the prices of the balancing service market.

Gate closure is 1 h before delivery, much later than in most other countries, and competitive intraday markets are available.

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\(^8\) This equaled about 55% of the total installed wind power capacity and 8% of the total installed power plant capacity (see Cen˜a, 2007c).
This allows RES-E producers to adjust their schedules to improved forecasts.

4.3.4. What are the regulations for grid access and who pays for RES-E-related grid reinforcements?

Grid access requirements for renewable generators are regulated under the UK Grid Code as for any other generators (NGET, 2007). Depending on the intended point of connection, the developer has to apply for a grid connection with National Grid or the respective distribution system operator. In the latter case, the impact on the transmission level has to be assessed for projects larger than 100 MW. Grid connection offers expire after 90 days, which is often too short for project developers to get all consents.

At distribution level, grid reinforcement costs are largely burdened on the RES-E project. Charging depends on the location of the connection point and the respective network topology. If infrastructure works are exclusively beneficial for the project, the respective "sole assets" are completely charged to the project in advance.

At transmission level the costs for the extension or reinforcement of networks are paid by the TSO and recovered from the network customers via the UoSC. Considerable financial investments are exclusively beneficial for the project, and the respective "sole assets" are completely charged to the project in advance.

4.3.5. Is the effect of intermittent RES-E on electricity market prices relevant for RES-E producers?

There are no figures available on the influence of RES-E on spot market prices in the UK. Presumably wind energy penetration in the UK is still too low to notice its effect on spot market prices. Assuming higher wind energy shares in the future, the resulting price decrease would directly affect the revenues of the RES-E producer.

5. Discussion: comparison of market integration approaches in the countries examined

Tables 4 and 5 summarise the research questions and results of the country case studies. It becomes clear that these countries follow contrasting approaches in allocating the responsibility for the power market integration of RES-E. The responsibilities are not only defined by the RES-E support scheme, but also by balancing regulations, grid code, and other market regulations.

This section will summarise the pros and cons of these market integration approaches and discuss under which conditions it seems justified to exempt RES-E generators from their market responsibility, or to assign full or partial market responsibility to them.

5.1. Pros and cons of market risk minimisation

RES-E support schemes are frequently compared under the aspect of risk minimisation for RES-E projects (e.g. Mitchell et al., 2006; Ragwitz et al., 2007). Mitchell et al. (2006) point out that risk reduction is an important way of increasing the effectiveness and efficiency of a support scheme, because lowering project risks reduces the costs of capital for the project developer and makes a larger number of projects attractive. They distinguish more precisely between price risk (RES-E electricity sales price), volume risk (limitation of sales volume), and balancing risk. Mitchell et al. (2006) conclude that risk minimisation is the major reason why the German support system has been more effective and efficient than the British so far.

This argument is supported by Ragwitz et al. (2007) that give quantitative evaluation of the efficiency of RES-E support in different European countries in 2004 and 2006 by comparing the effectiveness of the main support instrument (increase of electricity generation compared to the additional realisable midterm potential to 2020) with the expected profit of the RES-E generator. For onshore wind, the assessment by Ragwitz et al. (2007) clearly shows that the Spanish and German feed-in tariff schemes reach the highest effectiveness rates (in 2006 approximately 21% Spain, 16% Germany), despite relatively low expected producer profits (approximately 20 €/MWh in Spain, 7 €/MWh in Germany). This is explained by the low market risk. The Spanish feed-in premium option is found equally effective while providing higher profit margins (approximately 29 €/MWh in 2006), reflecting the higher market risks. In the same assessment, the UK quota system shows a low effectiveness rate for onshore wind (approximately 4%), despite high expected profits (approximately 11%)

One can argue, however, that in the end all these risk translate to price risks: electricity price, ROC price risk, imbalance price risk.

An update for 2006 was provided within the Commission Staff Working Document SEC(2008) 57; according to Ragwitz et al. (2007), the profit was calculated as specific discounted average return on every kWh produced, taking into account income and expenditure of the entire lifetime of a technology.
This is correlated directly to high risk premiums for financing wind projects in the UK.

The comparison of types of policy instruments provides, however, only part of the picture. As the country analysis has shown, the market risk for RES-E generators does not only depend on the predominant support instrument, but also on balancing and grid regulations. The coverage of grid reinforcement or imbalance costs can be considered as indirect public support that is not included in most quantitative comparisons of support schemes. Furthermore, administrative barriers and other non-financial issues are a high influence on the producer risk (see also Ragwitz et al., 2007).

### Table 4
Overview of the RES-E framework for Germany, Spain, and the UK

<table>
<thead>
<tr>
<th>RES-E share 2005 (%)</th>
<th>Germany</th>
<th>Spain</th>
<th>UK</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind power capacity 2007</td>
<td>10.4 22,250 MW</td>
<td>17.2 15,345 MW</td>
<td>4.1 2400 MW</td>
</tr>
<tr>
<td>Maturity of wind market</td>
<td>Mature</td>
<td>Mature</td>
<td>Not mature</td>
</tr>
<tr>
<td>Grid congestion barrier</td>
<td>High Feed-in tariffs</td>
<td>Medium Feed-in tariff option</td>
<td>Feed-in premium option 2004</td>
</tr>
<tr>
<td>RES-E support scheme</td>
<td>Average support payment for onshore wind 2007 (including electricity price)</td>
<td>51.7–81.9 €ct/kWh</td>
<td>73.2 €ct/kWh</td>
</tr>
<tr>
<td></td>
<td>Average support payment for onshore wind 2007 (excluding electricity price)</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

### Table 5
Summary of research questions and answers for Germany, Spain and the UK

<table>
<thead>
<tr>
<th>RES-E support scheme</th>
<th>Germany</th>
<th>Spain</th>
<th>UK</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed-in tariffs</td>
<td>None</td>
<td>None</td>
<td>Full</td>
</tr>
<tr>
<td>Feed-in tariff option</td>
<td>TSO</td>
<td>Utility</td>
<td>RES-E producer</td>
</tr>
<tr>
<td>Feed-in premium option 2004</td>
<td>TSO</td>
<td>RES-E producers &gt; 10 MW; forecasting; low imbalance charges for deviations &gt;20%; balancing; utility n.a. (1.5 €/MWh)</td>
<td>2.6 (1.4) €/MWh</td>
</tr>
<tr>
<td>Feed-in premium option 2007</td>
<td>Not available; profile transformation costs for all RES-E, paid by TSO: 3.4-5.4 €/MWh</td>
<td>2.6 (1.4) €/MWh</td>
<td>Not known</td>
</tr>
<tr>
<td>(4) Cost allocation for grid reinforcement</td>
<td>“Shallow”: no costs for RES-E producers</td>
<td>“Shallowish”: full distribution level costs, 20% transmission level costs for RES-E producers</td>
<td>“Shallowish”: full or partial distribution level costs, no transmission level costs (but liability) for RES-E producers</td>
</tr>
<tr>
<td>(5.1) Spot market price reduction per 1000 MW wind power in operation</td>
<td>1.89 €/MWh</td>
<td>2–3 €/MWh</td>
<td>So far not measurable</td>
</tr>
<tr>
<td>(5.2) Relevance of effect for RES-E producer</td>
<td>So far low; no relevance for RES-E producers</td>
<td>So far low; no relevance for RES-E producers</td>
<td>So far none; in principle full relevance for RES-E producers</td>
</tr>
</tbody>
</table>

* According to LBD(2007), higher figures are given by the TSO.
There is another important issue when comparing the efficiency of RES-E support policies. Exempting RES-E from market risk means that they will not respond to market price signals. They have no incentive for cost-optimised operation with regard to market and system demand. The same is true for the grid infrastructure. If there are no locational price signals, RES-E projects have no incentive for locational efficiency with regard to the electricity grid. From the macroeconomic perspective on societal costs there are thus two opposing effects of market risk minimisation:

- efficiency gains due to lower risk premiums and lower required support payments, and
- efficiency losses due to reduced market response and less system optimised behaviour.

When assessing the second effect, it is also important to consider to what extent wind energy and other RES-E are able to respond to the respective market signals. In the following sections, we will compare the exposure and response of wind power and biomass technologies to the three types of market risks that have been investigated in the country case studies:

- price risks from forward electricity markets;
- scheduling and imbalance price risks; and
- costs and risks associated with grid connection and grid reinforcement.

5.2. Exposure to price risks in forward electricity markets

5.2.1. Attribution of electricity market price risks

The interaction of the examined support schemes with electricity market prices is depicted by Fig. 6. The price risk allocation can be summarised as follows:

- Fixed feed-in tariffs like in Germany and the regulated tariff option in Spain isolate RES-E generators from market prices and risks. Since the supplementary payment varies with market prices, consumers carry the price risk.
- Feed-in premiums like in Spain 2004–2006 (RD 436/2004) let RES-E generators face the full market price risk and give them incentives to adjust their operation to market demand. They may also lead to high RES-E profits that can endanger political acceptance. Potentially they could also result in low profits that could endanger the project profitability, although in Spain this risk is limited through the fallback option of the fixed feed-in tariff.
- Bounded feed-in premiums like in Spain since 2007 (RD 661/2007) adjust the bonus during project lifetime according to market prices by giving a lower floor or an upper cap. They expose the RES-E generator to market price signals, but limit both price risks and profit margins.
- Quota schemes expose the RES-E generators to two independent market price risks, the electricity price risk and the certificate price risk. With regard to electricity market integration, they have the same characteristics as a feed-in premium scheme.

The exposure to market price risks favours large RES-E producers that can hedge these risks effectively. Independent producers need to close PPAs with utilities or other intermediaries. This will require higher revenues to make their projects profitable. If network operators are obliged to buy the produced RES-E at a fixed tariff, the direct support level will be structurally lower, since it does not need to cover a risk premium for the market price risk. On the other hand, the feed-in tariff scheme isolates RES-E producers from the electricity market.

5.2.2. Response of RES-E to electricity market price signals

As discussed earlier, wind power plants have zero fuel costs and very low operational cost, but cannot influence the availability of their fluctuating source. Whenever their source is available, they will be inclined to feed their full production into the grid. In fact, this behaviour is promoted by all the examined support schemes, since the support payment is paid per produced kWh, and thus the production revenues are above zero even if market prices are close to zero. Wind power operators will therefore hardly react to electricity price signals, except in the scheduling of their maintenance periods. This would change, if “negative” market prices (i.e. penalties for over-feeding the system) were applied, or if support payments were organised in a more flexible way.

On the other hand, biomass and other RES-E with certain fuel costs and/or storage capacity will adjust their operation to market price signals, at least to some extent, depending on their ability to adjust operation in a flexible way (storage of biogas or other primary energy).
5.2.3. Future challenges

At high RES-E penetration rates, the characteristics of wind energy may lead to new market price challenges. In power markets with high wind concentrations, market prices will erode whenever wind feed-in is high. Currently, this effect is of limited relevance in most countries (Denmark is a notable exception). In the future, it may threaten the profitability of wind power plants in case they are exposed to market prices and the support scheme does not recognise the level of their revenues. Even if they close a power purchase agreement with an intermediary, this effect may still become relevant, because the value of the PPA will be estimated on the basis of market prices, and the intermediaries will anticipate the price decrease. Under a fixed feed-in tariff regime, this price risk will be transferred to consumers. Under a quota scheme, structurally higher certificate prices can be expected. Under a premium scheme, the premium would have to be adapted to keep projects profitable.

On the other hand, the increased use of wind energy will also lead to a devaluation of existing conventional power plants due to decreasing full-load hours. A cost-efficient structure of conventional power plants will reflect the impacts of renewable energies in the system. If the increased shares of renewables and the adjustment of the structure of conventional power plants do not happen at the same pace, the market may react with extreme prices. Capacity payments may help the market to adjust the power system to provide appropriate amounts of flexible (backup) capacity.

Options to limit the spot price effect of wind energy could be a better interconnection of European power markets, which would decrease the effect by delivering electricity to other power markets with less low-cost electricity supply, or an effective demand side management that increases electricity demand in times of high wind power penetration, e.g. by utilising certain electric appliances mainly during these hours. The latter option is already used in Denmark.

Table 6 summarises the RES-E price risks and response in forward markets.

5.3. Exposure to generation scheduling and imbalance settlement risks

5.3.1. Attribution of forecasting and balancing risks

The forecasting and balancing risk does not only depend on the support scheme, but also on general market regulations.

- In Germany, the forecasting and balancing of RES-E production supported under the feed-in tariff scheme is done by the TSO, therefore RES-E producers carry no balancing risk. In principle, central forecasting has the potential for high precision, but only if the TSO has an incentive to minimise costs. It remains a regulatory challenge to ensure a cost-effective profile transformation.
- Under the Spanish feed-in tariff option, all RES-E generators are obliged to forecast their production, but scheduling is done by the utility. The RES-E generators pay only very limited penalties for schedule deviations. This limits their risk to a low level, but still gives some incentive for accurate forecasting. Individual forecasting for the stochastic production of wind power is, however, not very reliable. Central forecasting is still done by the utility and the transmission network operator.
- Under the Spanish feed-in premium option, RES-E generators are fully responsible for scheduling their production and paying imbalance charges, but imbalance prices—and thus price risks for RES-E generators—are limited. Except for utilities that produce both RES-E and conventional power, wind power generators will tend to use intermediaries that will pool larger number of generators and hedge the balancing risk.
- In the UK, RES-E generators are fully balancing responsible and have to pay full imbalance charges. They thus carry the full balancing risk. Again, independent wind power producers benefit from intermediaries that forecast their generation, schedule the production and sell the electricity.

An individual forecasting obligation thus favours large players and strengthens the role of intermediaries, because the forecasting quality improves with the number of forecasted generators. It also guarantees smooth system integration, because the wind power producers or their intermediaries will adjust their schedule during the day and delivery and thus minimise imbalance costs. Competitive intraday and balancing service markets are a precondition for the efficient integration.

5.3.2. Response of RES-E to imbalance price signals

The predictability of wind is limited. It becomes more accurate the shorter the time period to actual delivery. The availability of intraday markets and a late gate closure for schedule adjustments thus improve the market response of wind energy and lower the individual imbalance costs of the wind power operator.
Table 7: Summary: imbalance price risk and response of RES-E

<table>
<thead>
<tr>
<th>RES-E support scheme</th>
<th>Germany</th>
<th>Spain</th>
<th>Feed-in premium option</th>
<th>Feed-in premium option</th>
<th>UK</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Feed-in tariffs</td>
<td>Feed-in tariff option</td>
<td>2004</td>
<td>2007</td>
<td>Quota obligation based on tradable green certificates</td>
</tr>
<tr>
<td>Imbalance charges for RES-E generator</td>
<td>None</td>
<td>RES-E producers &lt;10 MW: none; RES-E producers &gt;10 MW: limited imbalance charges</td>
<td>Full imbalance charges, but price limitations</td>
<td>Full imbalance charges</td>
<td></td>
</tr>
<tr>
<td>Price risk from forecasting and balancing RES-E generators</td>
<td>None</td>
<td>RES-E producers &lt;10 MW: none; RES-E producers &gt;10 MW: limited imbalance charges</td>
<td>Medium risk (full risk, but limited for all market players)</td>
<td>High risk</td>
<td></td>
</tr>
<tr>
<td>Incentive for RES-E generators to adjust schedules to improved forecasts</td>
<td>(−)</td>
<td>(+)</td>
<td>(++)</td>
<td>(++)</td>
<td></td>
</tr>
<tr>
<td>Ability to respond to imbalance price signals: wind</td>
<td>(−)</td>
<td>(−)</td>
<td>(−)</td>
<td>(−)</td>
<td></td>
</tr>
<tr>
<td>Ability to respond to imbalance price signals: biomass</td>
<td>(+)</td>
<td>(+)</td>
<td>(+)</td>
<td>(+)</td>
<td></td>
</tr>
</tbody>
</table>

Nevertheless, the stochastic generation profile of wind power needs to be combined with other flexible power units.

Biomass technologies face no significant problems when scheduling their generation, and they also do not require other balancing requirements than conventional producers. Thus, balancing issues are of low relevance for biomass technologies. Table 7 summarises the RES-E price risks and response in forward markets.

5.3.3. Future challenges

New challenges arise at high concentrations of wind power plants, at least in regions with strongly fluctuating wind occurrence and steep wind gradients. Since almost all wind power plants will influence the system imbalance in the same direction (e.g. in the case of a sudden wind calm), system imbalance may increase to a high level in the case of unpredicted wind conditions, and possibly even create challenges for system stability. In such situations, the imbalance cost for wind energy projects may become very high, even under competitive conditions. Imbalance costs thus pose a high-end barrier to wind power development, if the wind power projects are fully exposed to this price risk. Across Europe there are intense regulatory and technical discussions on adequate answers to these problems (e.g. balancing across control zone, incentives for additional regulation reserve, advanced support schemes that promote system adequacy, etc.).

5.4. Exposure to grid connection and system planning risks

5.4.1. Attribution of grid connection and system planning risks

Lengthy and untransparent administrative procedures for grid connection are often the highest entrance barrier to RES-E development. Examples of such barriers are the intransparent grid connection negotiation process in Spain and the limited validity of grid connection offers in the UK. In Germany, the guaranteed grid access coupled with relatively smooth administrative procedures has been one major factor for rapid market growth.

Grid connection is also a financial issue for RES-E projects, especially if the integration of RES-E plants requires grid reinforcement. The allocation of grid connection charges influences project profitability as well as the spatial allocation of generators.

- Under “shallow” grid connection charges like in Germany, only the costs of the physical connection to the nearest grid connection point have to be carried by the RES-E project; upstream reinforcement costs are split among all network users. This approach minimises the costs for the project developer, but gives no incentive to consider grid requirements in the choice of plant location.
- Under “deep” connection charges, as formerly applied in the UK, upstream reinforcement costs are to be carried by the RES-E project. This gives an incentive to minimise grid reinforcement costs, but burdens high costs on the project developer.
- Under “shallowish” connection charges like in Spain and now in the UK, only a certain share of grid reinforcement costs has to be carried by the RES-E project. This approach is partly cost-reflective and limits development risk, if the share of the reinforcement costs to be borne by the project is fixed in time. If the process to determine these costs is intransparent like in Spain, or if financial liabilities considerably exceed the actual cost share like in the UK, the hindrance to the project development may be more significant than the overall cost benefit.

Cost-reflective behaviour of the project developer will limit the necessary grid reinforcement and minimise the additional costs for the electricity system. On the other hand, from a macro-economic perspective, grid reinforcement costs will be lower if assigned to the system operator, because the RES-E project developers will have to pay higher cost of capital than the TSO.

5.4.2. Response of RES-E to locational price signals regarding system planning

Most RES-E technologies are decentralised generation technologies that depend on the availability of their source at the site of RES-E production. The network integration of RES-E may require reinforcement of the electricity system that was designed for central fossil power plants and not for distributed generation.
In this respect, wind energy poses a special challenge, since sites with high wind yields are often located in weak grid environments. If RES-E projects have to pay part of the related grid reinforcement costs, this will give them an incentive to choose a plant location that requires minimum grid reinforcement. Depending on the respective grid infrastructure, however, this choice is often limited. The project developer needs to balance the reinforcement costs against the conditions of an alternative site with better grid conditions. A major criterion for the site selection is the availability of the wind source. If distribution grid reinforcements are concerned, there is some potential for locational optimisation. On the other hand, if transmission grid reinforcements are required, their costs may become a prohibitive barrier to RES-E development in a whole region.

Biomass technologies pose less of a challenge to grid integration, but they also exhibit limited flexibility in adjusting their location to grid requirements (e.g. agricultural biogas plants are bound to their farm environment; large plants with external feed are more flexible).

5.4.3. Future challenges

If the ambitious European RES-E deployment targets are to be met, adaptations of the network infrastructure are unavoidable to integrate large shares of wind power. It seems reasonable to minimise the related costs by locational price signals, but full cost coverage of necessary grid extensions by the RES-E projects could prevent substantial market growth. Alternatively, high costs for RES-E projects would need to be compensated by high support payments. Thus, the adaptation of grid infrastructure required to integrate large shares of wind power will, in any case, require a proportion of public financing.

The long lead times of transmission grid reinforcements remain a critical obstacle for RES-E generators, even if reinforcement costs are carried by consumers. The political challenge is to speed up the required infrastructure projects, and, in the meantime, to implement efficient mechanisms for congestion management that do not endanger the profitability of RES-E plants.

Table 8 summarises the locational price risk and response.

5.5. Which market integration approach seems suitable under which conditions?

There is no straightforward answer to what extent RES-E should be assigned market risks. There is a trade-off between higher risk premiums in the case of market risk exposures on the one side, and lower risk premiums but additional regulatory challenges on the other side. The right choice strongly depends on the level of RES-E penetration, the competitiveness of the respective market and the goal of the policy maker. At low rates of RES-E penetration the integration challenge is not significant and the cost-reflective behaviour of RES-E of less importance than if RES-E hold a significant share in the electricity system. If the goal is to effectively introduce renewable energies to a market in a short period of time, it seems appropriate to minimise their risks and system responsibility. This approach will also minimise the level of support payments required to make RES-E projects profitable, but will require a high level of state regulation. If RES-E shares are higher and their impact on the system becomes more relevant, it seems justified to burden more responsibility and risks on RES-E projects in order to give them an incentive for cost-reflective market behaviour. A precondition should be that the respective markets are mature and competitive. Furthermore, policy makers should consider the ability of different RES-E technologies to react to these market signals, i.e. to adjust their operation according to market prices, to minimise their schedule deviations, and to avoid grid reinforcements. Without such ability, the exposure of RES-E to market signals will hardly lead to cost benefits for society. In this case, alternative regulatory incentives for efficient market integration should be considered.

Looking at the three examined countries under this perspective, some draft policy recommendations can be derived.

In Germany, the increasing RES-E share may allow for a direct electricity market participation of larger RES-E projects. The currently discussed introduction of a feed-in premium option could thus be a good step towards further market integration of RES-E, but introduces the problem of over- and under-compensation. On the other hand, the low liquidity of the German balancing service market might decrease the efficiency of market integration. Thus, integration policies should not only focus on renewables but also on increasing the competitiveness of the markets. An option to improve the efficiency of market integration under the feed-in tariff scheme could be an optimised design of the profile transformation mechanism, i.e. incentives for cost-efficient profile transformation. Different options are discussed in the course of the Renewable Energy Sources Act amendment 2009.

Regarding system planning, the switch to a partly shallowish regime could help to control grid reinforcement costs on distribution level.

Spain follows a dual approach to RES-E market integration: generators can choose between low and almost full responsibility. For taking more responsibility and risks, they are awarded higher profit margins, but price risks in the forward electricity and the balancing market are still limited by upper and lower boundaries. There are, however, possibilities to improve the cost efficiency of wind power support, considering the good Spanish wind conditions and the relatively high financial support level (the fixed tariff and the minimum support level under the flexible option are considerably higher than the average remuneration for good wind sites in Germany). Furthermore, improvements could be made.

<table>
<thead>
<tr>
<th>Table 8</th>
<th>Summary: locational price risk and response of RES-E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany</td>
<td>Spain</td>
</tr>
<tr>
<td>Grid connection charging</td>
<td>“Shallow”: no grid extension charges for RES-E producers</td>
</tr>
<tr>
<td>Incentive for locational optimisation</td>
<td>(*) distribution grid; (-) transmission grid</td>
</tr>
<tr>
<td>Ability to respond to locational price signals: wind</td>
<td>Yes</td>
</tr>
<tr>
<td>Ability to respond to locational price signals: biomass</td>
<td>Yes</td>
</tr>
<tr>
<td>Further transmission grid reinforcement required</td>
<td>Yes</td>
</tr>
</tbody>
</table>
Regarding grid connection procedures and allocation of grid reinforcement costs. The shallowish approach seems generally justified, but its transparency should be increased.

Considering the relatively small market share of RES-E in the UK, RES-E generators are exposed to very high risks, both in the electricity market and the support scheme. In order to reduce these risks for smaller RES-E projects, the introduction of long-term power purchase agreements could be considered (Johnston et al., 2007). Adjusted balancing regulations, e.g., introducing upper ceilings to the imbalance market price, could limit the risks for wind energy. Also, it seems appropriate to further adjust grid connection procedures, e.g., to prolong the validity of grid connection offers (as already started in 2007), and to decrease liabilities for grid reinforcement.

Looking at the broader picture of the European Union, there are many countries with a low RES-E share. A general recommendation for developing the RES-E markets of these countries is not to burden the full market and grid connection risk on the RES-E generators from the beginning, but to start with a limited risk approach. This will also allow smaller and independent RES-E producers to enter the electricity market. Particularly in the wind energy sector, a high risk approach clearly favours large and well-established power producers, since fluctuating RES-E are confronted with higher market risks than other power producers.

These recommendations could be next steps from the current market perspective. On a medium timescale, if wind energy shares are becoming higher, more advanced policy instruments might be required to tackle the new price and balancing risks (i.e., the decreasing electricity market revenues in times of high wind feed-in and the risk of high imbalance costs), which could become a high-end barrier for wind energy development. How such policies could look in detail cannot be investigated here, but one might think of new types of power purchase agreements to hedge these risks (see e.g., Johnston et al., 2007). Furthermore, electricity market regulations might need to be adapted to the special characteristics of wind energy, in order to profit from this energy source in an optimal way.

6. Conclusions

The analysis has shown that there are contrasting approaches for integrating RES-E into electricity markets. In Germany, the full responsibility for electricity sales, balancing and grid integration of RES-E is transferred to the TSO, and related costs are passed to consumers. In Spain, RES-E generators can choose between full and partial responsibility for market integration of their produced electricity. In the UK, RES-E generators are fully responsible. No matter what approach is chosen, RES-E is physically integrated into the market and will influence its price level in forward and balancing markets.

In all three fields of analysis, there are trade-offs between a “high risk” and a “low risk” approach:

- **Price risks in forward electricity markets**: The exposure to price risks will lead to higher risk premiums for the RES-E generator than the isolation from price risks. It will, however, also lead to a better match of supply and demand, if RES-E generators are capable of scheduling their generation according to market prices. Wind power plants will hardly react to such price signals.

- **Forecasting and balancing risks**: Central forecasting of RES-E production by the TSO has the potential for high precision, but only if the TSO has an incentive to minimise costs. It remains a regulatory challenge to ensure a cost-effective profile transformation. If RES-E generators are responsible for balancing their generation, it is an incentive to RES-E producers to minimise imbalance costs. On the other hand, such an approach leads to higher risk premiums for smaller RES-E producers and possibly to a market concentration of larger players in the wind power market, since the forecasting quality improves with the number of forecasted generators.

- **Grid connection and system planning risks**: The allocation of grid reinforcement costs to the project developer will lead to cost-reflective behaviour, limit the necessary grid reinforcement and minimise the additional costs for the electricity system. On the other hand, given the current structure of the electricity grid that is not prepared for large-scale RES-E integration, these costs can become a high barrier for further RES-E deployment, especially in the wind energy sector.

From a policy maker’s perspective, the assignment of market risks to RES-E projects is thus a two-sided issue. Compared to a minimum risk approach, higher market risks increase the project costs for RES-E generators. Consequently, a higher level of financial support is required to stimulate RES-E development. In contrast, the exposure to market risks may also give an incentive to RES-E generators to make efficient use of the respective market and act in a cost-reflective way, thus limiting the indirect costs to society. If RES-E generators are not exposed to market risks, the regulatory challenge arises how to organise central market integration (mostly by the TSO) in a cost-efficient way. Without incentives for efficient integration and respective control mechanisms, the indirect costs to society might be higher than necessary.

The special characteristics of wind power will increasingly influence forward markets, balancing markets, and system planning requirements. They also set natural limits to the response of wind power to market prices and locational price signals. For this reason, policy makers should consider with care to what extent wind power and other RES-E should be exposed to such price risks. Wind and solar energy seem more critical in this respect than other RES-E technologies. The attribution of market risks should be based on a number of parameters: the share and structure of renewables in the system, the specific regulatory framework of the electricity market, and on the competitiveness of the electricity market. In any case it is clear that in order to integrate large shares of wind energy into the system, electricity grids and market regulations will also need to be adapted to the new generation characteristics.

References


Johnston, C., et al., 2007. Adjusted balancing regulations, e.g., introducing upper ceilings to the imbalance market price, could limit the risks for wind energy. Also, it seems appropriate to further adjust grid connection procedures, e.g., to prolong the validity of grid connection offers (as already started in 2007), and to decrease liabilities for grid reinforcement.

2007. Closing the gaps in the electricity grid and partial responsibility for market integration of their produced electricity. Particularly in the wind energy sector, a high risk approach clearly favours large and well-established power producers, since fluctuating RES-E are confronted with higher market risks than other power producers.


References


