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Veröffentlichungsversion / Published Version

Arbeitspapier / working paper

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Empfohlene Zitierung / Suggested Citation:

Gawel, E., & Purkus, A. (2013). *Promoting the market and system integration of renewable energies through premium schemes - a case study of the German market premium*. (UFZ Discussion Papers, 4/2013). Leipzig: Helmholtz-Zentrum für Umweltforschung - UFZ. <https://nbn-resolving.org/urn:nbn:de:0168-ssoar-342696>

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UFZ Discussion Papers

Department of Economics

4/2013

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Erik Gawel, Alexandra Purkus

January 2013

Promoting the Market and System Integration of Renewable Energies through Premium Schemes

– A Case Study of the German Market Premium

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Abstract: With the share of renewable energies within the electricity sector rising, improving their market (i.e. inclusion in the allocative processes of the electricity market) and system integration (i.e. enhanced responsibility for grid stability) is of increasing importance. To transform the energy system efficiently while ensuring security of supply, it is necessary to increase the alignment of renewable electricity production with short- and long-term market signals. By offering plant operators a premium on top of the electricity market price, premium schemes represent a potential option for achieving this, and have been implemented by several EU member states. This paper focuses on the case study of the German market premium scheme, which has been adopted as part of the 2012 amendment of the Renewable Energy Sources Act. Building on an evaluation of early experiences, we discuss whether the market premium in its current design improves market and/or system integration, and if it seems suitable in principle to contribute to these aims (effectiveness). Also, potential efficiency gains and additional costs of “administering integration” are discussed (efficiency). While market integration in a narrow sense (i.e. exposing renewables to price risks) is not the purpose of the German premium scheme, it has successfully increased participation in direct marketing. However, windfall profits are high, and the benefits of gradually leading plant operators towards the market are questionable. Incentives for demand-oriented electricity production are established, but they prove insufficient particularly in the case of intermittent renewable energy sources. It seems therefore unlikely that the German market premium scheme in its current form can significantly improve the market and system integration of renewable energies. To conclude, we provide an outlook on alternative designs of premium schemes, and discuss whether they seem better suited for addressing the challenges ahead.

Keywords: Renewable Energies, Market Integration, System Integration, Market Premium, Renewable Energy Sources Act (EEG), Efficiency

JEL Classification: H23; Q42; Q48

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– A Case Study of the German Market Premium

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1 Market and system integration of renewable energies as conditions for a successful transformation of the electricity sector

In recent years, the share of renewable energy sources (RES) in European gross electricity consumption has been steadily increasing, from 13.6% in 2005 (452.5 TWh) to 19.9% in 2010 (667.8 TWh) (BMU 2012). In order to meet the EU Renewable Energy Directive's 20-20-20 target (COM 2009), member states are planning to further up-scale renewable electricity production – according to National Renewable Energy Action Plans, by 2020 RES could reach a share of 34.5% in the EU electricity sector (BMU 2012; ECN 2011). Moreover, some member states have set ambitious long-term targets. In Germany, for example, the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) aims to increase the share of renewable energy sources in electricity supply to at least 35% by 2020, rising up to 80% by 2050 (sec 1 (2) EEG 2012). With this, RES are rapidly outgrowing their status as niche technologies, moving towards becoming the dominant energy technology in the electricity sector in the long term (Eclareon & Öko-Institut 2012; Winkler & Altmann 2012).

However, substituting a centralised energy system based on large-scale, base-load power plants for a mix of predominantly small-scale, decentralised renewable energy technologies, in which intermittent energy sources like wind and photovoltaics (PV) play an important role, poses considerable challenges for the efficiency and security of energy supply (BMU 2011; Neubarth 2011; Hiroux & Sagan 2010). To solve these, systemic approaches are necessary: apart from substituting fossil (and in the case of Germany, nuclear) energies for RES, a successful energy transformation requires investments in complementary conventional plants, an expansion of grid and storage capacities, as well as improvements in energy efficiency and energy savings (BMW & BMU 2010). Both for grid stability and the economic efficiency of electricity provision, effective short- and long-term market signals to producers are of central importance, as they provide incentives for demand-oriented and efficient deployment of existing plant capacities as well as for investments in increasing the flexibility of electricity production. At the same time, most RES technologies are not yet competitive at current market prices and still require public support.

By offering plant operators a premium on top of the electricity market price, premium schemes represent a potential policy option for aligning renewable electricity production with market signals, while providing incentives for RES investment. Consequently, premium schemes have been implemented by several EU member states in recent years (i.e. Cyprus, the Czech Republic, Denmark, Estonia, Finland, Germany, Italy, the Netherlands, Slovenia and Spain) (RES LEGAL 2012). The design of such schemes varies considerably, as do as their importance within national policy mixes for renewable energy support (cf. Kitzing et al. 2012). This article examines the effectiveness and efficiency of the German market premium scheme, which has been adopted as part of the 2012 amendment of the Renewable Energy Sources Act.

In Germany, technology-specific feed-in tariffs guaranteed for 20 years have proven to be a successful instrument for promoting the expansion of renewable energies (cf.

Haas et al. 2011; Mitchell et al. 2006; Ragwitz et al. 2007). In 2000, when the Renewable Energy Sources Act came into force, renewable energy installations produced 39,181 GWh of electricity, covering 6.8% of gross electricity consumption; in 2011, 123,186 GWh were produced from RES, providing 20.3% of electricity demand (BMU 2012). However, in combination with priority purchase and transmission rules, publicly administered feed-in tariffs also shield renewable energy producers from both price- and quantity-related market signals (Brandstätt et al. 2011; Wustlich & Müller 2011). For achieving an efficient mix of energy sources, renewable energies cannot remain permanently detached from competition between alternative technologies. The necessity to align investment and production decisions with scarcity signals gives rise to the challenge of market integration, i.e. the inclusion of RES in the allocative processes of the electricity market through an equilibrium electricity price valid for all energy technologies.¹

Additionally, security of supply considerations require that grid stability is ensured at all times. The EEG priority transmission rules, however, exempt RES from the task of balancing supply and demand – on the contrary, electricity production which is independent from demand and, in the case of wind and solar power, also intermittent, imposes additional burdens on grid stability. At the same time, the balancing costs for other components of the energy system increase, reducing the system's overall cost efficiency. With the rising share of RES in the energy mix, an increase in regional grid congestions and voltage fluctuations can already be observed, necessitating short-notice interventions by Transmission System Operators (TSOs) (which are legally based on sec 11 EEG and sec 13 (2) EnWG; c.f. Brandstätt et al. 2011; Borggreffe & Nüßler 2009; TenneT 2012; 50Hertz 2012). Moreover, particularly in the case of wind power, the coincidence of high production levels with low demand can cause negative price spikes at the electricity exchange, which can involve significant economic costs (Brandstätt et al. 2011; Andor et al. 2010; Nicolosi 2010). The rising importance of RES therefore brings about the additional challenge of system integration, i.e. renewables must accept responsibility for grid stability, provide balancing services, and align production with demand to a greater extent.

Lastly, a fundamental question is how to design the institutional transition from the current market introduction regime, which is characterised by administered feed-in tariffs and priority purchase and transmission rules, to a systemically integrated market price regime. In 2012, the amendment of the Renewable Energy Sources Act (EEG 2012) introduced a premium scheme as the central instrument to address these challenges. The aim of the so-called “Marktprämie” (market premium) is to provide market experience to renewable plant operators and incentives for demand-oriented electricity production (Fraunhofer-ISI et al. 2011). At the same time, the former feed-in tariff regime remains in place because most RES technologies have yet to reach grid parity (i.e. RES electricity production is more expensive than sourcing electricity from the public

¹ The equilibrium electricity price we define as the uniform marginal cost-based price resulting hourly at the electricity exchange from the balance between supply and demand.

grid). As an optional, i.e. parallel, component for integration, the market premium does not aim for a fundamental change in the renewable energy support system, but is intended to promote a smooth transition and prepare the ground for a future transition to a market-based regime.

Building on an evaluation of early experiences, this article examines whether the German market premium scheme in its current design improves market and/or system integration, and if it seems suitable in principle to contribute to these aims (effectiveness). Also, potential efficiency gains and additional costs of “administering integration” are discussed (efficiency). To conclude, we provide an outlook on alternative designs of premium schemes, and discuss whether they seem better suited for addressing the challenges ahead.

2 The market premium scheme in the Renewable Energy Sources Act 2012

2.1 Design of the German market premium scheme

Since 01.01.2012, when the Renewable Energy Sources Act 2012 (EEG 2012) came into force, RES plant operators can choose between receiving a fixed feed-in tariff (FIT) and a sliding market premium on a monthly basis (Lehnert 2012; Wustlich & Müller 2011). Alternatively, if certain requirements are fulfilled, electricity suppliers can directly market RES electricity and benefit from a reduction of their EEG surcharge (i.e. the surcharge suppliers pass on to their customers to finance the EEG feed-in tariffs) (sec 39 EEG 2012). Also, RES producers can choose to directly market their electricity without receiving any reimbursements, although they still benefit from priority transmission and grid access rules (sec 33a et seqq. EEG 2012). Whereas in the FIT scheme, TSOs are responsible for selling RES electricity on the spot market (cf. Bundesnetzagentur 2010), plant operators choosing the premium scheme or other forms of direct marketing have to market their electricity themselves. In the market premium scheme, producers are paid the difference between the feed-in tariff a plant would be entitled to and the average market value of the electricity generated. Moreover, they receive a management premium intended to cover additional costs resulting from their direct participation in the market, e.g. balancing costs incurred when actual production deviates from forecasts, and costs for handling market transactions (EEG 2012 annex 4 no. 1; Sensfuß & Ragwitz 2011; Lehnert 2012; Wustlich & Müller 2011; see fig. 1):

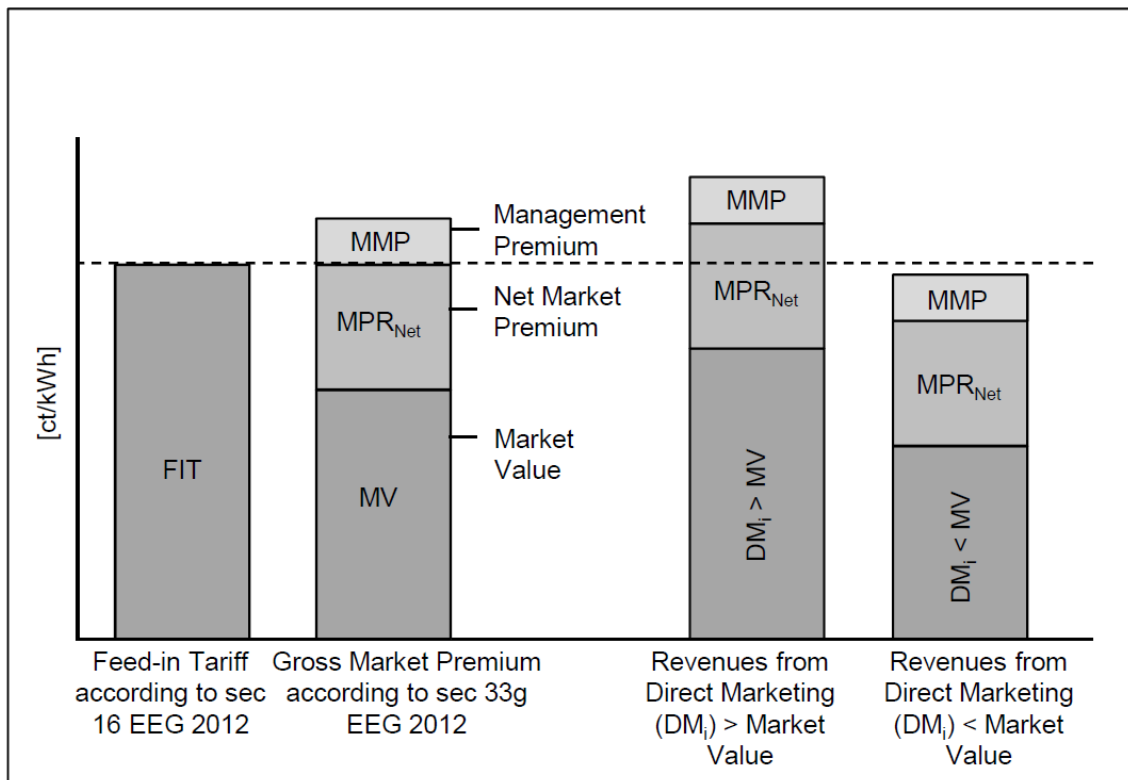
$$\text{MPR}_{\text{Gross}} = \text{FIT} - \text{MV} + \text{MMP}$$

$\underbrace{\hspace{10em}}_{\text{MPR}_{\text{Net}}}$

Where

- MPR_{Gross}: total premium in the market premium scheme (“gross premium”)
- FIT: technology-specific feed-in tariff a plant could claim according to sec 16 EEG 2012
- MV: actual monthly average of the relative (= technology-adjusted) market value
- MMP: technology-specific management premium
- MPR_{Net}: compensation for the difference between market value and feed-in tariff (“net premium”).

Fig. 1 Overview of the German market premium scheme



Source: own illustration, based on Lehnert 2012; Wustlich & Müller 2011; EEG 2012 annex 4 no. 1

The average market value is calculated monthly ex post based on hourly prices at the electricity stock exchange EEX (EEG 2012 annex 4 no. 2; Sensfuß & Ragwitz 2011). For dispatchable, non-intermittent RES, the market value equals the actual monthly arithmetic average of hourly contracts on the spot market (EEG 2012 annex 4 no. 2.1). For wind and photovoltaics, a technology-specific “relative” market value is used instead (EEG 2012 annex 4 no. 2.2 et seqq.), because wind is frequently produced at times when demand and electricity prices are low, while the production of solar pow-

er tends to peak around noon, when prices are high.² As a result, wind energy tends to have a lower market value compared to dispatchable RES, while solar power has a higher relative market value (Sensfuß & Ragwitz 2011; Lehnert 2012). The management premium also distinguishes between dispatchable and intermittent RES; to account for the costs of balancing forecasting errors, the latter receive significantly higher premiums (Sensfuß & Ragwitz 2011). For 2012, the management premium for wind and PV amounts to 12€/MWh, while dispatchable RES receive 3€/MWh (EEG 2012 annex 4 no. 2.2 et seqq.). However, management premium rates are subject to a pronounced yearly decrease, which, in the case of wind and solar power, has been tightened even further through the Management Premium Ordinance (MaPrV) enacted at 29.08.2012 (see tab. 1).

Tab. 1 Management premium rates according to EEG 2012, annex 4 no. 2.1 et seqq., and MaPrV 2012

Year	Dispatchable RES	Wind / PV according to EEG 2012 (old)	Wind / PV according to MaPrV, 29.08.2012 (new)	
			Plants whose output can be remote controlled	Other plants
2012	0,30 ct/kWh	1,20 ct/kWh		
2013	0,275 ct/kWh	1,00 ct/kWh	0,75 ct/kWh	0,65 ct/kWh
2014	0,25 ct/kWh	0,85 ct/kWh	0,60 ct/kWh	0,45 ct/kWh
From 2015	0,225 ct/kWh	0,70 ct/kWh	0,50 ct/kWh	0,30 ct/kWh

Source: own compilation

The total premium paid according to the market premium scheme (MPS), i.e. the “gross” market premium, therefore consists of the sliding “net” market premium (MPR_{Net}), defined as the difference between technology-specific feed-in tariff and the actual monthly average of the technology-specific market value, and the management premium (MMP).

Additionally, the market premium scheme is complemented by several measures intended to improve the framework conditions for the market and system integration of RES (cf. Gawel & Purkus 2013). For example, participation of RES and storage systems in balancing markets has been facilitated (Bundesnetzagentur 2012), and electricity from new storage installations has been temporarily exempted from grid charges (sec 118 (6) EnWG 2011). Also, for biogas plants using the market premium scheme, a flexibility premium offers additional incentives by compensating for investment costs in

² The relative market value of wind and PV is calculated by dividing the sum of average hourly sales revenues of wind or PV at the electricity exchange by the amount of wind or PV power produced in that month (Sensfuß & Ragwitz 2011; EEG 2012, annex 4 no. 2.2 et seqq.).

additional storage and production capacities required for a more flexible electricity generation (sec 33i EEG).

2.2 Objectives of the German market premium scheme

In order to analyse the effectiveness of the German market premium, it seems useful to distinguish between three basic objectives which can in principle be pursued through premium schemes:

- *Market integration (in a narrow sense):* By aligning reimbursements for RES production with the average market price level, a premium scheme can increase the exposure of market participants to price risks (Eclareon & Öko-Institut 2012). In such a scheme, the revenues of producers would in principle be determined by the electricity market.
- *System integration:* Furthermore, a premium scheme can contribute to the management of balancing risks in the electricity system, by providing RES producers with incentives to supply balancing power and ancillary services (Eclareon & Öko-Institut 2012).
- *Direct marketing:* Finally, a premium scheme can incentivise a change of distribution channels, to increase the direct participation of RES plant operators in the electricity market. From an economic perspective, however, this does not constitute an end in itself (Knopp et al. 2012), but serves the objectives of improving market and system integration.

To improve the market integration of RES, the German market premium scheme is meant to provide plant operators with incentives to evolve from “passive participants to active market actors” (Fraunhofer-ISI et al. 2011, p. 13, own translation). By switching from feed-in tariffs to direct marketing, producers may gather experience with market operations, while at the same time a stronger alignment of production decisions with market prices is encouraged. By selling electricity when demand – and therefore the market price – is high, producers can earn revenues above the average market values used in calculating the market premium, thereby improving their income relative to the fixed feed-in tariff (BMU 2011; Lehnert 2012). By providing the chance of higher revenues, the net market premium therefore provides *incentives for changing distribution channels*. The management premium, meanwhile, is intended to compensate for the cost risks of direct marketing, i.e. the comparative transaction costs of participating in direct marketing.

The possibility of earning higher revenues by shifting electricity generation to hours with high demand or low supply is also meant to incentivise demand-oriented electricity production, which would improve the system integration of RES (BMU 2011; Neubarth 2011). Here, the objective is not merely to increase participation in direct marketing, but to realise changes in production behaviour, which are relevant for the system’s efficiency (*incentives for changing production behaviour*). According to estimates by Consentec and R2B Energy Consulting (2010), such changes in RES production behaviour could save 425 million € in 2015 in the conventional energy system,

or 670 million € in 2020 (discounted values, base year 2010). In these estimates, cost savings are mainly realised through changed production patterns of dispatchable RES. For intermittent RES, increasing the flexibility of electricity supply would require extensive investments in storage systems (Consentec & R2B Energy Consulting 2010). While this led to debates about their inclusion in the premium scheme (cf. Fraunhofer-ISI et al. 2011, *Votum IWES*, S. 182), the net market premium is intended to encourage wind and PV plant operators to at least explore short-term options for providing balancing power (e.g. participation in balancing markets, voluntary curtailment in response to negative power prices, or the alignment of maintenance planning with low-demand hours) (Fraunhofer-ISI et al. 2011). Moreover, in the mid-term, the market premium scheme should provide incentives for more flexible plant designs and the development of energy storage systems (Fraunhofer-ISI et al. 2011). Also, the scheme is expected to improve the quality of forecasts of feed-in quantities, as the exchange of information between plant operators and marketing actors is more direct than in the FIT (Möhrle et al. 2012), and to reduce costs for balancing forecasting errors, which producers in direct marketing have to bear themselves (Sensfuß & Ragwitz 2009; Consentec & R2B Energy Consulting 2010). However, though an increased demand-orientation of RES production is encouraged, priority transmission rules remain intact for RES plants participating in direct marketing (sec 8 and 9 et seqq. EEG 2012; Schumacher 2012; Wustlich & Müller 2011), as well as rules pertaining to the priority connection of RES plants to the grid (sec 5 et seqq. EEG 2012; Wustlich & Müller 2011).³ Consequently, RES producers in the premium scheme remain relatively shielded from balancing and volume risks (cf. Eclareon & Öko-Institut 2012).

Increasing the market integration of RES in a narrow sense, meanwhile, is not the aim of the German market premium scheme. In its current design, the net market premium eliminates the general price risk almost completely, by covering the difference between average market prices and feed-in tariff rates (Nestle 2011). As such, decisions about the mix of energy sources employed remain directed by publicly administered feed-in compensation, as opposed to market forces. Exposing plant operators to an increased market price risk is explicitly not the market premium scheme's intention, because this would diminish planning certainty and decrease the willingness to invest in RES (cf. Sensfuß & Ragwitz 2009). Therefore, the following discussion can be limited to the aspects of direct marketing and system integration.

³ If RES plants in the market premium scheme are forced to reduce output as a consequence of feed-in management measures (sec 11 EEG 2012), they are entitled to compensation for lost revenues, same as plants in the FIT scheme (sec 12 (1) EEG 2012; Schumacher 2012).

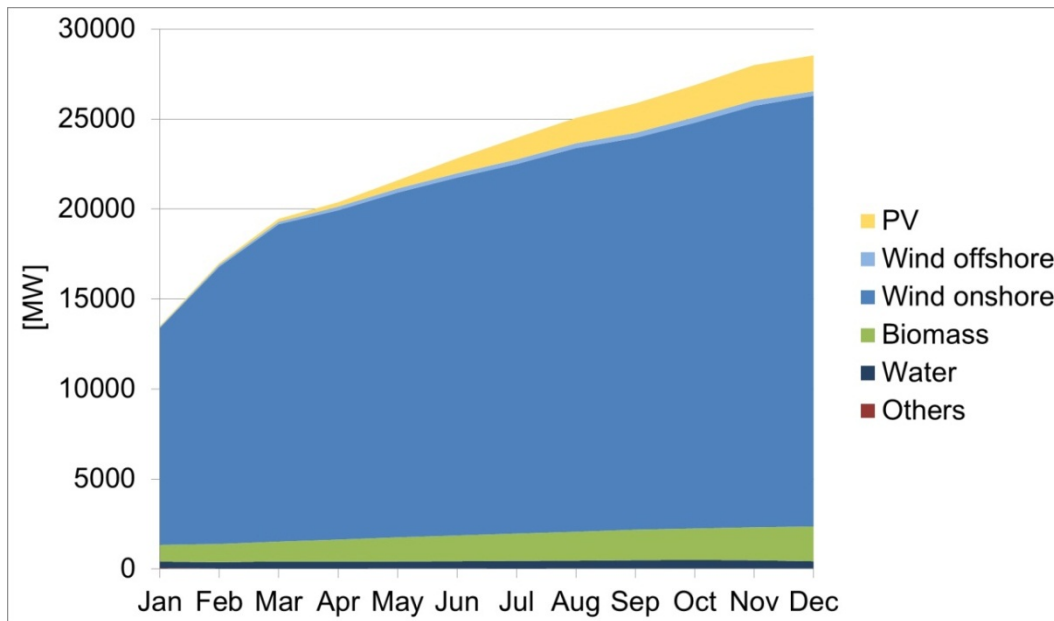
3 The performance of the German market premium scheme – an evaluation of early experiences

3.1 Use of the scheme

After the first year of its implementation, the market premium scheme has been successfully established as an alternative to the EEG feed-in tariffs (figures 2 and 3). In particular, the degree to which wind power plants use the premium scheme is considerably higher than initially expected (50Hertz et al. 2011). Also, an increasing number of bioenergy plants changed to the market premium regime: while in January 2012 933 MW of installed capacity chose this form of direct marketing, this number rose to 1963 MW in December (EEG-KWK-G 2012a), which is equivalent to about a third of the total installed biomass capacity of 2011 (cf. BMU 2012). While data for the installed capacity in the market premium scheme is available on a monthly basis, this is not yet the case for data about quantities of electricity produced. However, based on forecasts of average monthly full load hours for 2012, estimates are possible (cf. IE Leipzig 2011; 50Hertz et al. 2011). According to these, an estimated 65% of all on- and offshore wind power production between January and October 2012 was reimbursed according to the market premium scheme (cf. fig. 4). For bioenergy plants the premium scheme's share was smaller, but still significant, amounting to an estimated 26% (cf. fig. 4). For PV installations the feed-in tariff remains the dominant support instrument – only about 3% of the plants have been using the premium scheme; as the small, decentralised scale of production results in high transaction costs when electricity is marketed directly, this finding is hardly surprising. For landfill, sewage treatment and mine gases, direct marketing aiming for a EEG surcharge reduction is more important than the premium scheme (cf. fig. 4; EEG-KWK-G 2012a). Likewise, water power plants use the premium scheme only to a limited extent (in 2012, an average of 400MW of installed water power capacity used the scheme each month, which is equal to about 9% of the installed capacity at the end of 2011), while it is not relevant at all for geothermal power plants (fig 2; EEG-KWK-G 2012a; BMU 2012).

Compared to 2011, the market premium scheme significantly increased participation in direct marketing – in particular, direct marketing was strengthened considerably for the wind, PV and biomass technology groups (cf. EEG-KWK-G 2012a). At the same time, direct marketing for reducing the EEG surcharge according to sec 39 EEG has become less relevant (cf. EEG-KWK-G 2012a), as eligibility requirements have been tightened and achievable benefits reduced (Hummel 2012; Lehnert 2012).

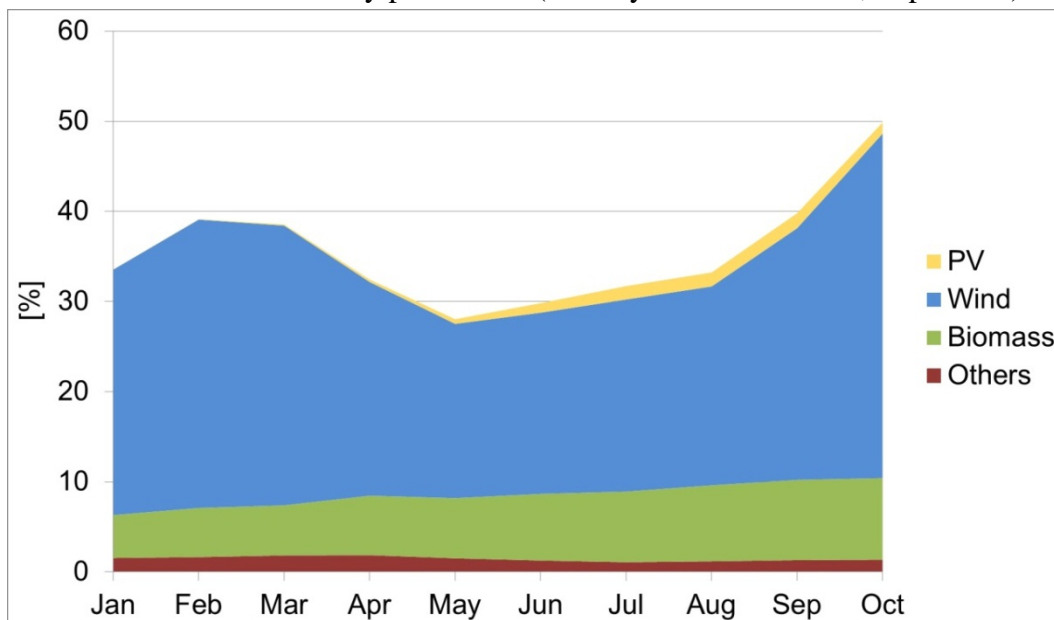
Fig. 2 Usage of the market premium scheme by technology group
(January-December 2012, installed capacity in megawatts)



Note: "others" encompass geothermal power, landfill gas, sewage treatment gas and mine gas

Source: own illustration, based on EEG-KWK-G 2012a

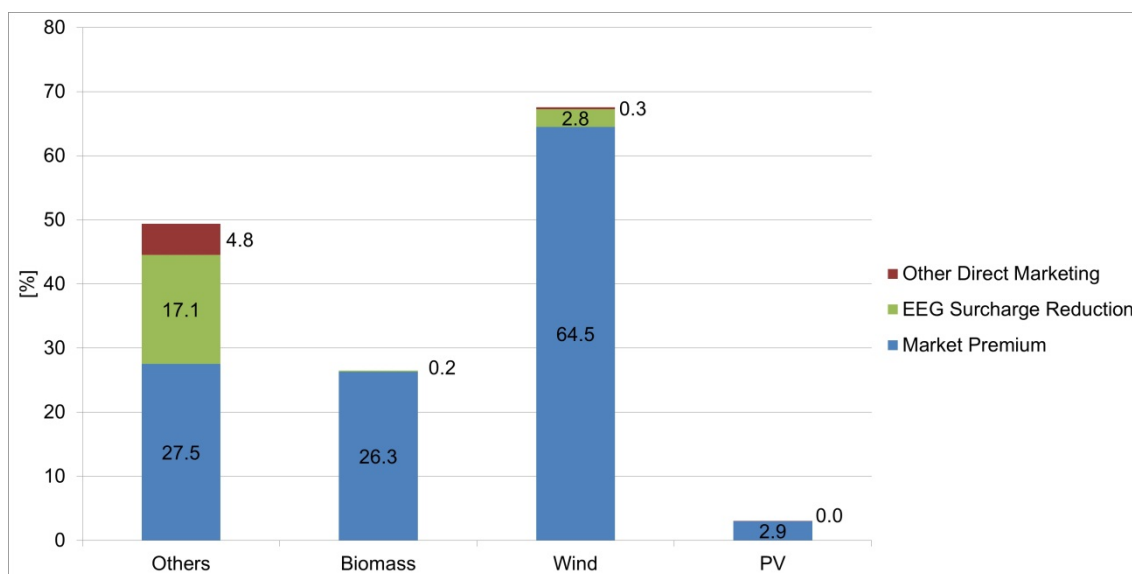
Fig. 3 Share of electricity production compensated by the market premium scheme
in total RES electricity production (January-December 2012, in per cent)



Note: "wind" includes onshore and offshore wind power, "others" include water power and landfill gas, sewage treatment gas and mine gas

Source: own illustration, based on data about RES electricity in the FIT scheme marketed by the TSOs (EEG-KWK-G 2012b), and estimates of directly marketed electricity amounts, using data about installed capacities (EEG-KWK 2012a) and forecasts for monthly average full load hours in 2012 (IE Leipzig 2011)

Fig. 4 Shares of different direct marketing options in RES electricity production (January-October 2012, in per cent)



Source: own illustration, based on own estimates of directly marketed electricity amounts (cf. EEG-KWK 2012a; EEG-KWK-G 2012b; IE Leipzig 2011)

3.2 Effectiveness of the German market premium scheme

The market premium scheme can be considered effective if it increases participation in direct marketing (3.2.1), and improves the system integration of RES (3.2.2).

3.2.1 Impacts on participation in direct marketing (incentives for changing distribution channels)

Mainly, the market premium scheme supports the market integration of RES by encouraging producers to gain experiences with market processes by participating in direct marketing. In this way, it is intended to facilitate a future transition towards a market regime (cf. Sensfuß & Ragwitz 2009; Consentec & R2B Energy Consulting 2010). Given that the market premium scheme has caused a significantly higher number of plant operators to choose direct marketing than in previous years, it can be considered effective in this regard (Kopp et al. 2012; cf. also EEG/KWK-G 2012a). However, while the main incentive for changing distribution channels should be the possibility of realising higher profits through demand-oriented production and intelligent marketing (cf. BMU 2011, section 2), it is to be expected that the management premium plays an important role in the successful uptake of the premium scheme. While additional profits from price-oriented direct marketing are subject to market risks, the management premium represents a certain additional income, as long as it surpasses the actual costs of changing the distribution channel (cf. section 3.3).

Meanwhile, when directly participating in electricity and balancing markets, large-scale RES producers and electricity utilities can benefit from increasing returns to scale and existing market experience. As a result, they may have a competitive advantage compared to small-scale producers, causing concerns that the market premium scheme could promote concentration processes in the RES sector (Nestle 2011). While this question merits further empirical analysis, the premium scheme has initiated the development of business models which also handle direct marketing activities for small RES producers (cf. e.g. Statkraft 2012; Uken 2012).

3.2.2 Impacts on system integration (incentives for changing production behaviour)

Although RES producers remain shielded from general market price risks, the market premium scheme does set incentives to react to short-term price signals (cf. section 2.2). For evaluating the scheme's impacts on system integration, it is necessary to discuss whether these incentives are effective in promoting demand-oriented electricity production. For this purpose, a fundamental distinction has to be made between incentives for a short-term adaptation of production decisions and long-term investments in energy storage systems and flexible RES plant design. Given that the inclusion of wind power and PV was debated prior to the market premium scheme's implementation, the effects on the system integration of intermittent RES are discussed first.

To date, for wind power and PV installations curtailment remains the main option for steering their feed-in of electricity into the grid (Brandstätt et al. 2011). For more comprehensive investments in flexible plant design and storage systems, which are still at an early stage of technological development, the incentives offered by the market premium scheme are considered to be insufficient (Fraunhofer-ISI et al. 2011, Vote IWES, p. 148; Nestle 2011; Dietrich & Ahnsehl 2012).

Meanwhile, plant operators only receive the market premium for the amount of electricity they actually sell; in the absence of storage options, electricity production is therefore profitable as long as the market price is higher than the plant's marginal costs minus the amount of the gross market premium which the producer expects to receive (Andor et al. 2010; Klessmann et al. 2008; cf. tab. 2). Since the marginal costs of wind and solar power production approach zero, this means that for intermittent RES, electricity production remains profitable even if market prices are negative. Moreover, plant operators do not have to bear balancing risks; if they are forced to reduce their output in order to ensure grid stability, they are entitled to compensation (Schumacher 2012; Wustlich & Müller 2011; sec 12 (1) EEG 2012). As a result, the behavioural incentives of the market premium scheme will only encourage voluntarily curtailment, when the surplus of electricity on spot markets becomes so great that sellers have to offer buyers a larger amount than the gross market premium (i.e. net market premium plus management premium) they expect to receive.⁴ If this is the case, the market premium scheme

⁴ Notwithstanding, the market premium scheme sets incentives for shifting maintenance activities and other unavoidable output reductions to hours with low or negative electricity prices (cf. Fraunhofer-ISI et al. 2011).

improves economic efficiency compared to a feed-in tariff system, where production is completely detached from market price developments. From an economic perspective, however, production would only make sense if market prices at least covered marginal production costs, that is if market prices were positive in the case of RES with marginal costs close to zero (see tab. 2).

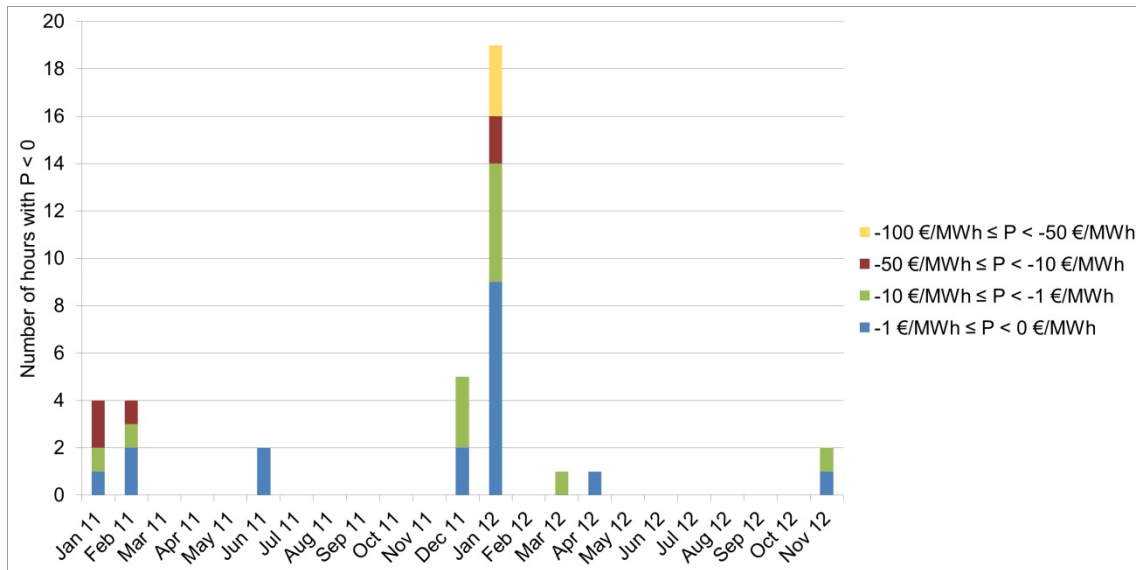
Tab. 2 Operational profitability and economic efficiency of RES production, depending on market prices (P), marginal costs of production (MC), and the expected value of the gross market premium ($E\{MPR_{Gross}\}$)

	Production is profitable for plant operators, if	Production is economically efficient, if
EEG market premium scheme	$P \geq MC - E\{MPR_{Gross}\}$ For $MC = 0$: $P \geq -E\{MPR_{Gross}\}$	$P \geq MC$ For $MC = 0$: $P \geq 0$
EEG feed-in tariff	$P \in \mathbb{R}$	

Source: own compilation, based on Andor et al. 2010

Consequently, the market premium scheme only sets effective incentives for demand-oriented production when electricity market prices are highly negative, i.e. smaller than the negative expected value of the gross market premium. To assess the relevance of this effect, an examination of the frequency and magnitude of negative price events in the spot market of the European Electricity Exchange (EEX) is informative (see fig. 5). In 2011, negative prices occurred in 15 hours of the year, affecting a total of 464.2 GWh. In 2012, prices were negative in 23 hours (until November), affecting 747.4 GWh. However, slightly negative prices between 0 €/MWh and -1 €/MWh are the most frequent category, whereas prices below -10 €/MWh only occurred in three (2011) and five (2012) hours respectively (at the same time, the management premium for wind and PV alone amounts to 12€/MWh). As a result, plant operators of RES with marginal costs close to zero would only be incentivised to forego production in a very limited number of hours in a year. Windfall profits in connection with the management premium lead to additional distortions of price signals for demand-oriented electricity generation (see section 3.3). For intermittent RES, it seems therefore unlikely that the market premium scheme will cause a significant shift in production patterns towards a stronger demand-orientation.

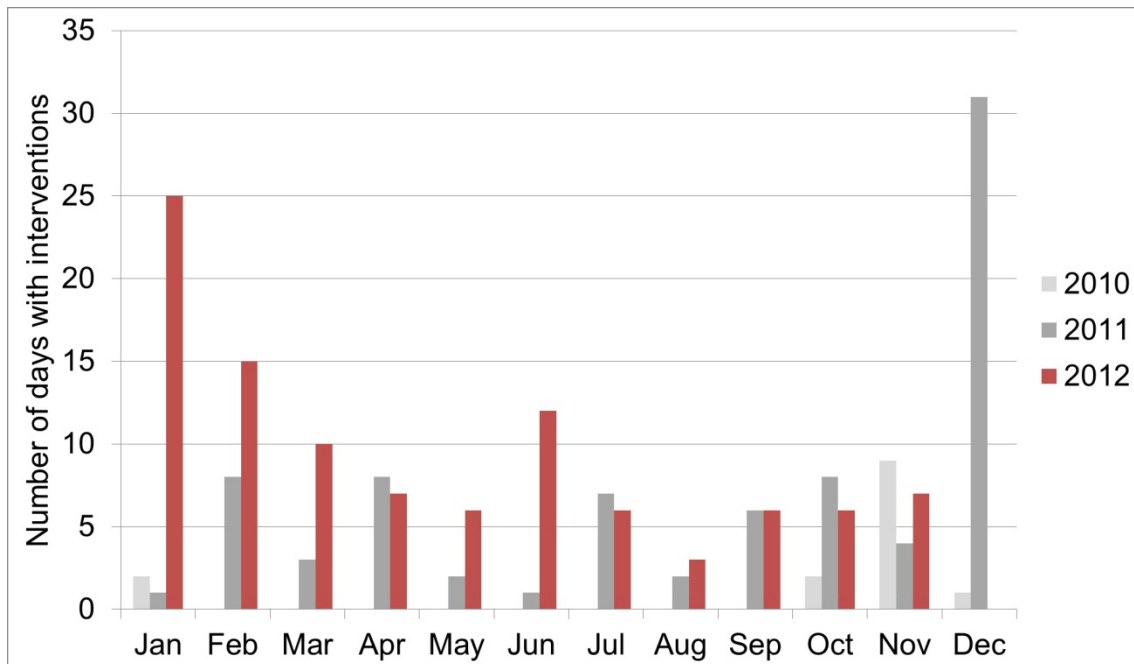
Fig. 5 Negative electricity prices on the EPEX spot market, 01.01.2011-30.11.2012



Source: own illustration, based on EPEX Spot 2012

Furthermore, up to now the market premium scheme has not been able to break the trend towards an increasing number of congestion management measures TSOs have to take in order to safeguard grid stability (according to sec 11 EEG 2012 and sec 13 (2) EnWG, see fig. 6). Several factors are relevant in explaining the rising number of interventions, such as the growing share of intermittent RES in total electricity production and the increasing regional divergence of electricity supply and demand (cf. Borggreffe & Nüßler 2009). An estimation of the influence of individual factors and potentially positive effects of the premium scheme on grid stability is beyond the scope of this paper. However, the continuing increase in the number of congestion management measures demonstrates that the market premium scheme as the primary instrument for supporting RES system integration is clearly not sufficient.

Fig. 6 Congestion management measures according to sec 11 EEG in the control areas of the TSOs 50Hertz and TenneT (January 2010-November 2012)⁵



Source: own illustration, based on 50Hertz 2012; TenneT 2012

In the case of dispatchable RES like bioenergy, water power, and landfill, sewage treatment and mine gases, the market premium scheme can effectively support system integration if a switch towards flexible electricity production can be implemented with relatively little effort (Consentec & R2B Energy Consulting 2010). For bioenergy plants in particular, the market premium scheme provides higher incentives than for wind and PV installations, because producers incur variable costs for energy carriers. With marginal costs above zero, bioenergy plant operators would therefore have a higher willingness to voluntarily curtail output when electricity prices are low; moreover, the combustion of bioenergy carriers can be shifted to hours with higher prices. However, even for biogas plants the incentives set by the market premium scheme have been shown to be too low to encourage necessary investments in flexible plant designs (Fraunhofer-IWES et al. 2011). Unlike with other technologies, for biogas plants the flexibility premium has been created to fill this gap (sec 33i EEG 2012; Fraunhofer-IWES et al. 2011). Meanwhile, to confirm if the incentives provided by market premium and flexibility premium in combination are sufficient to encourage investments in flexible plant designs, empirical studies are necessary.

⁵ The control areas of the TSOs 50Hertz and TenneT cover Northern and Eastern Germany and include the entire coastline (Netzentwicklungsplan 2012); as a result, the system integration of intermittent RES is particularly challenging for these control areas. In the control areas of the remaining TSOs TransnetBW and Amprion no interventions according to sec 11 EEG 2012 have been necessary yet (as of August 2012, personal communication).

3.3 Efficiency of the German market premium scheme

A central criterion for evaluating the market premium scheme is whether it succeeds in improving the economic efficiency of RES electricity supply. Given that technology-specific feed-in tariffs remain the basis for the calculation of the net market premium, the scheme does not lead to a reduction in average electricity generation costs (see section 2.2). However, it would contribute to efficiency improvements, if

1. the electricity system's grid stabilisation and balancing costs were reduced
2. the additional costs necessary for administering the scheme did not overcompensate these savings.

3.3.1 Additional costs

Additional costs arise for the organisation of direct marketing activities and the administration of the market premium scheme, which exists in parallel with the FIT scheme's distribution channels. No data is available yet about the transactions costs to grid operators of processing premium calculations and payments. With regard to producers' handling costs of direct marketing, which are compensated by the management premium, the existence of windfall profits has been criticised since shortly after the scheme's introduction (BÜNDNIS 90/DIE GRÜNEN 2012; IZES 2012). Based on recommendations from Fraunhofer-ISI et al. (2012), the management premium ordinance (MaPrV, adopted 29.08.2012) significantly lowered management premium rates for intermittent RES in 2013 and the following years, and introduced a distinction between wind and PV plants according to remote control possibilities (cf. tab. 1).

However, this adjustment of premium rates does not stop plant operators from obtaining windfall profits by claiming the market premium because of its high management premium, without significantly changing their production behaviour (IZES 2012). Because of the strong depression in the management premium's design, it can be profitable for producers to change back into the feed-in tariff scheme in the mid-term, placing doubts on the permanence of market and system integration effects (IZES 2012). While problematic, this effect is difficult to mitigate; at least in its implementation phase, the market premium scheme has to offer plant operators additional income possibilities, to incentivise a change of distribution channels (see section 2).

Overall, additional costs of the market premium in comparison with the feed-in tariff scheme are primarily caused by the management premium (cf. BMU 2011; Sensfuß & Ragwitz 2011; see section 2). Based on data on installed capacities using the market premium scheme (see fig. 2) and estimates of the corresponding quantities of electricity produced, an assessment of these costs is possible (see tab. 3). For 2012, total management premium costs can be estimated to amount to 460 Mio. € (cf. also Nick-Leptin 2012; Hummel 2012). These were predominantly caused by wind power plants participating in the premium scheme (89% of the costs), followed by biomass (6% of the costs) (cf. tab. 3). Initial calculations prior to the instrument's implementation assumed management premium costs of only 200 Mio. €; however, usage of the market premi-

um scheme has been higher than expected (Nick-Leptin 2012; Sensfuß & Ragwitz 2011).

Tab. 3 Estimation of management premium costs in 2012 in €

RES	Estimated management premium costs 2012	Share of total costs [%]
Water	4,857,546	1.06
Landfill gas, sewage treatment gas and mine gas	358,881	0.08
Biomass	26,882,997	5.84
Geothermal	0	0.00
Wind onshore	408,158,268	88.65
Wind offshore	9,555,972	2.08
Photovoltaics	10,599,016	2.30
Sum	460,412,680	100

Source: based on management premium rates for 2012 (EEG 2012 annex 4, no. 2.1 et seqq.), and an estimation of electricity quantities reimbursed by the market premium (own calculations, based on installed capacities participating in the market premium scheme (EEG-KWK 2012a) and 2012 forecasts of monthly average full load hours (IE Leipzig 2011))

Additionally, long-term savings could result from preparing market participants for a future change in the RES support regime towards stronger market orientation. However, it seems questionable if market experience gained by participation in direct marketing and respective learning effects can justify the instrument's additional costs (Consentec & R2B Energy Consulting 2010; IZES 2012). Moreover, if the market premium scheme is seen as a means to acquaint RES plant operators with market processes, this assumes that increasing the share of direct marketing now will save future costs of a system change. The fast, large-scale uptake of the market premium scheme (see section 3.1) demonstrates that RES producers are well able to react rapidly to changing framework conditions, moving from fixed feed-in tariffs to a direct participation in market processes within a short time (Kopp et al. 2012). Whereas in December 2011 a total installed capacity of 3563 MW was using direct marketing channels (predominantly for reducing the EEG surcharge), 14,666 MW were doing so in January 2012 (92% of which were claiming the market premium) (EEG/KWK-G 2012a, Wassermann et al. 2012). It appears that many RES actors can make use of existing experiences, trade connections and organisational structures in rapidly expanding direct marketing activities (cf. Wassermann et al. 2012). Consequently, the benefits of a gradual familiarisation with market distribution channels can be questioned, given that the emergence of market institutions and the adaptation to new framework conditions seems to be working well within the RES sector.

3.3.2 Impacts on grid stabilisation and balancing costs

The main benefit of the market premium, meanwhile, was intended to be the creation of “more flexibility in the overall system” (BMU 2011, p. 15, own translation), leading to a decrease in balancing and grid stabilisation costs. Therefore, for an evaluation of the market premium scheme, it is of central importance what efficiency gains could in fact be realised through market premium-induced, demand-oriented electricity production. To answer this question, in-depth empirical research or modelling efforts are required. In particular, it is necessary to analyse if the scheme’s system benefits are primarily provided by dispatchable RES, as predicted by Consentec & R2B Energy Consulting (2010). In the case of dispatchable RES, where production can be aligned with demand with relative ease, and where management premium rates are consequentially low, it seems probable that the market premium scheme can indeed bring about savings in the overall system. However, the costs of the flexibility premium for biogas plants would also have to be taken into account. On the other hand, it seems unlikely that the market premium will cause significant changes in the production behaviour of intermittent RES, because output reductions are only profitable when electricity prices are strongly negative (see section 3.2.2). At the same time, intermittent RES drive the additional costs of the market premium scheme – in total, 93% of the management premium costs are accounted for by onshore and offshore wind power and PV (cf. tab. 3). The adjustments implemented in the management premium ordinance (MaPrV 2012) will undoubtedly decrease the future costs of including intermittent RES in the scheme – for 2013, savings of 160 Mio. € are expected, increasing to 200 Mio. € in 2015 due to the premium’s degressive design (Fraunhofer-ISI et al. 2012). However, given the management premium’s role of setting incentives for changing distribution channels, this measure will also reduce the scheme’s attractiveness for wind and PV plants. Moreover, uncertainties about further adjustments in the future (cf. MaPrV 2012, annex 2) can be expected to further decrease the willingness to invest in demand-oriented production measures beyond merely a curtailment or maintenance planning. Under these conditions, it seems highly doubtful if the inclusion of intermittent RES can result in a significant decrease of grid stabilisation or balancing costs (cf. Hummel 2012).

Overall it seems unlikely that the market premium scheme in its current design significantly improves the efficiency of RES electricity supply. On the contrary, at least in the short term, it increases the costs of public support (BMU 2011; Consentec & R2B Energy Consulting 2010). For reaching a conclusion about the instrument’s efficiency, the central question is whether savings generated by an improved system integration of RES are not overcompensated by the additional costs of the scheme, which are mainly caused by the management premium. Further research is necessary to quantify system integration benefits. While for dispatchable RES efficiency gains seem plausible, a positive cost-benefit balance seems less likely in the case of wind power and PV. Given the low effectiveness of the market premium scheme in providing intermittent RES with incentives for demand-oriented production, and their high share in the instrument’s additional costs, a re-evaluation of their inclusion in the scheme is recommendable.

4 The market premium scheme's impacts on market and system integration of RES – taking stock

4.1 The market premium scheme in the EEG 2012

As demonstrated, it seems useful to distinguish between the different economic objectives of a premium scheme: market integration in a narrow sense (i.e. increasing the alignment of production with market prices); system integration (i.e. improving the responsibility of RES for balancing and grid stabilisation, by linking revenues to spot market prices); and the utilisation of direct marketing as a distribution channel, which is not an end in itself, but supports the other two objectives.

Against this background, conclusions concerning the market premium scheme as implemented in the EEG 2012 are divided:

1. Market integration in a narrow sense, i.e. letting market prices determine the electricity mix and guide investments, is not the objective of the solely optional market premium scheme. This is convincing, because an increase in the general price risk for RES would lead to significantly higher investment risks, thereby jeopardising the realisation of ambitious RES expansion targets.

2. Incentives for changing distribution channels are primarily set by the management premium, despite its intended role as compensation for higher transaction costs. These incentives are effective, but currently high windfall profits result from overly generous management premium rates; the necessity for corrective interventions, in turn, imposes uncertainties on market actors. As windfall profits are likely to be a major explanatory factor for the high uptake of the market premium scheme, the permanence of its effects on participation in direct marketing may be questioned. While increasing the degression rate of the management premium limits the scope for future windfall profits, it also lowers the attractiveness of the market premium scheme, resulting in a trade-off between effectiveness and efficiency. Given that the use of direct marketing does not constitute an end in itself, a central question is what additional benefits arise from a gradual familiarisation with market processes. The fast uptake of the scheme shows that the market is apparently able to evolve necessary institutions quite rapidly, making the benefits of a gradual, long-term learning process questionable. Markets and market actors react almost instantaneously to changes in framework conditions (cf. Kopp et al. 2012), which means that they would also do so at a later stage, once RES had actually reached grid parity and technological maturity.

3. The market premium scheme does set incentives for an improved system integration of RES: producers who adapt their feed-in profile to short-term market price signals can increase their revenue compared to receiving a fixed feed-in tariff, and contribute towards improved grid stability in the process. However, in the case of intermittent RES, these incentives are not sufficient to bring about a significant increase in flexibility of production beyond economically plausible reactions to relatively rare negative price spikes. Moreover, incentives are not strong enough to encourage investments in storage systems or flexible plant designs. Accordingly, a significant contribution to-

wards solving the urgent problem of integrating intermittent RES into the electricity system is not to be expected.

Overall, the market premium scheme as implemented in the EEG 2012 does not seem promising: in its current design, the instrument is neither effective nor efficient in promoting market and system integration. The scheme shifts RES production towards direct marketing, but a significant change in production behaviour is not to be expected; also, additional costs ensue, which are mainly driven by windfall profits. The market premium scheme may, however, set effective incentives for dispatchable RES when flexible load management is possible at low costs, as well as for biogas plants in combination with the flexibility premium; this remains to be confirmed empirically. For intermittent RES, which are responsible for a high share of the additional costs, windfall profits are likely to dominate. Long-term benefits from a gradual familiarisation with market distribution channels seem negligible; on the contrary, the inevitability of further corrective interventions may entail additional transaction costs due to political uncertainty.

4.2 Alternative design options for premium schemes

Meanwhile, the design of the market premium scheme in the EEG 2012 represents only one possible option; other variants have been implemented in other EU member states (Eclareon & Öko-Institut 2012; RES-LEGAL 2012). The role of premium schemes in overall RES support varies (cf. RES-LEGAL 2012). Germany and Spain are examples where the premium scheme exists alongside a comprehensive FIT system, and plant operators can choose regularly between the two schemes (annually in the case of Spain, and monthly in the case of Germany; the Spanish scheme, however, is currently closed for new entrants) (Klein et al. 2010; RES-LEGAL 2012). In Italy, the premium scheme co-exists with feed-in tariffs and a tender system, but depending on RES source and installation size producers may be restricted to a certain system (RES-LEGAL 2012). In the Netherlands, on the other hand, the premium scheme constitutes the main RES support instrument (Kitzing et al. 2012). Table 4 provides an overview of the different premium schemes that have been implemented in EU member states. A short overview of basic design options is followed by a discussion whether other variants might be better suited to promote market and system integration of RES than the German market premium scheme.

Tab. 4 Overview of premium schemes in EU member states

Type of premium scheme	Country	Premium design	Adjustment of premium rates
Fixed premium schemes	Denmark	Technology-specific bonus on top of the market price Generally, bonus payments are capped so that a maximum level set for the sum of market price and bonus is not exceeded; in certain cases, no maximum limit applies	Generally, adjustments require amendments in regulation; for some technologies, annual adjustments apply
	Czech Republic	Technology-specific “green bonus” on top of the market price	Bonuses for new plants are determined annually; for existing plants bonuses increase annually with the industrial production index
	Estonia	Fixed bonus on top of the market price, which is generally the same for all technologies	By regulatory amendment only
	Netherlands	Technology-specific premium on top of the market price Premium payments are allocated in several stages throughout the year; the premium increases with each stage, but as the total annual budget is capped, applicants for the later stages may not receive any support	Premium levels and the total available budget are determined annually
Sliding premium schemes	Cyprus	Premium payments cover the difference between a technology-specific, guaranteed tariff and market prices	The premium scheme expired on 31.10.2012
	Finland	Premium payments cover the difference between a fixed, technology-specific target price and the average market price of the previous three months. Target prices are reduced by 30€, if the market price falls below 30 €/per MWh	Quarterly; adjustment of target prices requires regulatory amendments
	Germany	Premium payments cover the difference between technology-specific feed-in tariffs and the actual monthly average of the technology-specific market value, plus a management premium	Monthly; adjustment of feed-in tariffs requires regulatory amendments
	Italy	Premium payments cover the difference between fixed, technology-specific feed-in tariffs and zonal hourly market prices, plus further premiums or bonuses that may be granted to a plant	Hourly; adjustment of feed-in tariffs requires regulatory amendments
	Slovenia	Premium payments cover the difference between technology-specific reference costs and reference market prices of electricity, which are multiplied by a technology-specific adjustment factor.	Annual adjustment of reference costs and forecast reference market prices
Intermediate models	Spain	Premium payments depend on hourly electricity market prices: plant operators receive a floor price, if prices are low; the market price plus a fixed premium for price levels between the floor and the cap; no premium, if prices are higher than the cap.	As of January 2012, both premium and feed-in tariff schemes have been suspended (no new plants can enter the scheme)

Sources: based on RES-LEGAL 2012; Eclareon & Öko-Institut 2012

4.2.1 Design characteristics of premium schemes

In general, a distinction can be made between schemes with a fixed and a sliding premium (cf. Kitzing et al. 2012). In fixed premium schemes, which have been implemented for example by Denmark and Estonia, plant operators receive a fixed bonus on top of the market price (Eclareon & Öko-Institut 2012); in the case of Denmark, the total sum of market prices and premium payments is capped for some technology groups (RES LEGAL 2012; Klein et al. 2010). Whereas in fixed premium schemes, revisions of premium rates generally require amendments in regulation, sliding premium schemes adjust regularly to take market developments into account. In Finland, Germany, Italy and Slovenia, premium payments adjust to cover the difference between a pre-determined target price or feed-in tariff and average market prices (RES LEGAL 2012; Klein et al. 2010). An intermediate model between fixed and sliding premium schemes has been implemented by Spain. Here, the premium adjusts hourly to guarantee at least a floor price. Between floor and a certain cap, a fixed premium is paid; if market prices are approaching the cap, premium payments gradually decrease, so that total income does not exceed the limit set by the cap. Beyond this point, producers simply receive the spot market price (Klein et al. 2010; Eclareon & Öko-Institut 2012; Couture & Gagnon 2010). Apart from the adjustment of premium rates, schemes also differ according to degression rules, caps, eligibility periods, and the degree of differentiation between technologies (RES LEGAL 2012). With the exception of Estonia, all countries differentiate between RES technology groups when determining premium levels; in some cases, the amount paid also depends on the size of installations and other characteristics (e.g. use of combined heat and power options) (cf. RES LEGAL 2012).

4.2.2 Impacts on market integration

An overview of premium designs shows that the instrument is frequently used to integrate RES more strongly in the market allocation mechanism than in the German model, i.e. market integration in a narrow sense is of higher relevance as a policy objective (cf. section 2). Fixed premium schemes in particular expose RES producers to considerable price risks, as payments are not adjusted to falling market prices (Eclareon & Öko-Institut 2012). But also in the context of sliding premium schemes, producers can be exposed to varying degrees of risk: if premium rates are frequently adjusted to actual market developments, risks for producers are minimised; if prices are averaged over longer periods (e.g. three months in the case of Finland), producers retain a higher risk of achieving substandard sales revenues (cf. tab. 4). Meanwhile, in both sliding and fixed premium schemes, producers bear higher volume and balancing risks than in feed-in tariffs; while the latter are usually combined with purchase obligations and TSOs are responsible for balancing, premium schemes generally require producers to market their electricity and pay for balancing forecasting errors themselves (Klessmann et al. 2008).

While using the price mechanism to guide production and investment decisions can improve the efficiency of electricity supply, several trade-offs arise with other policy objectives of RES support. Namely, these are trade-offs between efficiency and incen-

tives for innovation; efficiency and the cost-effectiveness of support; and efficiency and the aim of curtailing market power in the RES sector.

Efficiency and incentives for innovation: Fixed premium schemes might be seen as a Pigovian subsidy compensating for social net benefits but apart from that still maintaining the competition of technologies. Hence, these schemes are particularly close to the market, and favour cost-efficient technology choices. However, when a significant share of producers' revenue is determined by fluctuating market prices, investors may be more averse to invest in innovative technologies which are still a long way from becoming competitive. For promoting the deployment of innovative technologies, feed-in tariffs have the advantage of offering investors high planning certainty (Batlle et al. 2012). Sliding premium schemes which compensate for the difference between reference costs and market prices are likewise effective in reducing uncertainty for investors.

Efficiency and cost-effectiveness of support: If revenues of RES projects are uncertain, the costs of capital increase; therefore, in order to achieve the same effectiveness of incentives for RES investment, a premium scheme will require higher support payments per kWh than a fixed feed-in tariff (Mitchell 2006; Ragwitz et al. 2007; Klessmann et al. 2008; Couture & Gagnon 2010; Klein et al. 2010; Batlle et al. 2012). The greater the exposure of producers to market risks in a particular scheme's design, the more pronounced the necessary increase in support costs will be. Moreover, compared to a FIT system, the risk of overcompensation is higher for market premium schemes, because total remuneration is more likely to diverge from actual project costs once electricity prices influence revenue (Langniß et al. 2009; Mitchell 2006). Introducing price floors and caps as practiced by the Spanish model offers advantages in this respect, because price risks are limited for producers and society both (Ragwitz et al. 2007; Klein et al. 2010; Couture & Gagnon 2010). Generally, however, profit margins of plant operators are usually higher in premium schemes than under a feed-in tariff (Langniß et al. 2009; Mitchell 2006).

Efficiency and market power: Irrespective of the design variant, premium schemes are likely to increase market power, by giving large and vertically integrated utilities a competitive advantage over small-scale RES producers (Klessmann et al. 2008; Couture & Gagnon 2010; Batlle et al. 2012). Larger utilities can benefit from economies of scale in handling the transaction costs of direct marketing, and a diversified plant portfolio allows for a pooling of balancing and price risks (Klessmann et al. 2008; Batlle et al. 2012). Individual producers, on the other hand, have to rely on intermediaries for effective market participation, who require a share of the profits for their services (Klessmann et al. 2008; Batlle et al. 2012).⁶

Lastly, there are doubts whether the current marginal cost-based, energy-only design of the electricity market is suitable in the long term to integrate large shares of

⁶ In the Spanish wind power market, this impact on the market structure can already be observed: since the premium scheme has replaced feed-in tariffs as the dominant support instrument, incumbent generators are responsible for a significantly higher share of new investments than before (Batlle et al. 2012).

RES electricity production (EWI 2012; Kopp et al. 2012; Matthes 2012; Winkler & Altmann 2012; Nestle 2011; Klessmann et al. 2008). RES installations like wind and solar power plants can bid into the market with marginal costs close to zero, thereby reducing market prices and income for all producers. As a result, market incentives for investing in new capacities decline for RES and conventional power producers alike (Cramton u. Ockenfels 2012; Matthes 2012). Apart from a fundamental reform of the electricity market design, introducing capacity markets may be a possible solution which is currently considered by several countries (Winkler u. Altmann 2012; Kopp et al. 2012). This discussion, however, places doubts on whether increasing the participation of individual RES producers in electricity markets is urgently required, as long as the future of the market design itself is unclear. Rather, adjustments to the current support regime may increase complexity, impeding later system changes (Winkler u. Altmann 2012).

4.2.3 Impacts on system integration

The larger the share of revenue which is determined by market prices, the stronger the incentives for producers to ensure that they can provide electricity when prices are high (cf. Ragwitz et al. 2007; Klein et al. 2010; Eclareon & Öko-Institut 2012). However, the effectiveness of market signals ultimately depends on producers' ability to react to them (Ragwitz et al. 2007; Klessmann et al. 2008; Batlle et al. 2012). No matter which design variant of a premium scheme is chosen, wind energy and PV installations will, in the absence of storage systems, continue to feed-in electricity as long as total expected remunerations are positive. As the exposure of intermittent RES to market risks will nevertheless result in higher risk premiums being demanded for investment, and therefore higher support costs, their inclusion in premium schemes is heavily debated (cf. Klessmann et al. 2008; Hiroux & Saguan 2010; Batlle et al. 2012). Limiting premium schemes to dispatchable RES would be an option to capture a significant part of the potential system integration benefits while limiting additional costs (Klessmann et al. 2008; Consentec & R2B Energy Consulting 2010; Batlle et al. 2012). Incentives for intermittent plants to improve maintenance planning, forecasting and balancing would be lost, as well as, in the case of wind power plants, the incentive to adapt location choices to demand-compatible wind profiles (Hiroux & Saguan 2010). However, regulatory alternatives exist, e.g. the introduction of congestion pricing in the calculation of grid charges, or the setting of incentives for efficient balancing at the level of system operators (Klessmann et al. 2008). Here, an additional advantage is that fluctuations of individual plants can be balanced over a wider area (Klessmann et al. 2008), and that an optimisation between grid extension, storage investments, and demand-side management would be possible (cf. Nykamp et al. 2012). Moreover, investments in storage systems are generally considered to be more efficient on system level than on the level of individual plants (cf. Matthes 2012; Gatzen & Riechmann 2011; Nestle 2011). It may therefore be advantageous to improve the market and system integration of intermittent RES first of all on the level of transmission system operators, who in

Germany are responsible for marketing electricity under the feed-in tariff and maintaining grid stability (cf. Klessmann et al. 2008).

5 Conclusions

Based on this analysis, it seems unlikely that the German market premium scheme in its current design can significantly improve the market and system integration of renewable energies. While market integration in a narrow sense (i.e. exposing renewables to price risks) is not the purpose of the German premium scheme, it has successfully increased participation in direct marketing. However, the management premium component of the scheme gives rise to large windfall profits, and the benefits of gradually leading plant operators towards the market are questionable. In particular, the parallel existence of feed-in tariffs and premium scheme places doubts on whether the transition of plant operators towards direct marketing and changes in production behaviour will be permanent. Incentives for demand-oriented electricity production are established, but they prove insufficient particularly in the case of intermittent renewable energy sources.

By allowing market price fluctuations to determine a larger share of producers' revenues, fixed premium schemes or sliding premium schemes with less frequent adjustments may provide stronger incentives for demand-oriented production compared to the German market premium, and promote market integration in a narrow sense. However, efficiency gains from exposing RES producers to market risks have to be balanced against trade-offs with incentives for innovation, the cost-effectiveness of support, and potentially adverse impacts on the market structure of the RES sector. In order to realise ambitious RES expansion targets, cost-based, sliding premium schemes with frequent adjustments to market price developments seem preferable compared to benefit-based fixed premium schemes, because planning certainty for investors remains high. However, even if price risks are limited through the scheme's design, producers have to be compensated for higher volume and balancing risks; as a consequence, it can be expected that support costs will be somewhat higher than in the case of a fixed feed-in tariff in combination with purchase guarantees. The challenge of avoiding overcompensation is therefore not specific to the German market premium with its management premium, but a common characteristic of premium schemes.

Whether a sliding premium scheme is preferable to a feed-in tariff, depends ultimately on whether the benefits of enhanced system integration justify the additional costs. For intermittent RES, this seems doubtful, because the limited possibilities of wind and PV installations to react to short-term price signals impose fundamental constraints on the instrument's ability to improve their system integration. Rather, systemic concepts are required, which draw on all components of the energy system for addressing the challenge of system integration. For dispatchable RES, a sliding premium scheme could be a promising part of such an integrated concept, as long as it provides effective incentives for demand-oriented production without overly increasing market risks and impeding market access for small RES producers. In the German market pre-

mium scheme, planning certainty remains high; whether incentives are sufficient to encourage demand-oriented production and investments in flexible plant designs remains to be confirmed empirically. However, a premium scheme for dispatchable RES needs to be complemented by incentives for investments in storage systems, energy efficiency and demand-side management. In the case of intermittent RES, it seems advantageous to promote system integration first at the level of transmission system operators. Meanwhile, increasing the market integration of RES (in a narrow sense) is not recommendable, as long as grid parity has not been established and there are doubts whether the current electricity market design is suitable at all for integrating large shares of RES. In order to limit uncertainty about future framework conditions, a timely and transparent discussion of fundamental alternatives would be desirable, as well as the development of concepts which take all relevant aspects of the electricity system into account.

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