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Civic participation and cost efficiency

Key points for the financing of renewable energies and enabling demand response

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IASS POTSDAM

“The energy transition must be designed as a common project for the future to ensure that energy is produced safely, in a way which is environmentally compatible and socially acceptable and at competitive prices.
[…] The transition to an age of rigorous improvement in energy efficiency and to the use of renewable energies is a process that challenges the whole of society.”

Ethics Commission 2011

Contents

Summary and core statements

The energy transition continues to meet with broad approval in the German population. A large majority supports the expansion of renewable energies and the associated transition of the electricity system. Nevertheless, fundamental reform of the Renewable Energy Sources Act (EEG = Erneuerbare-Energien-Gesetz) and the design of the electricity market is required. A growing proportion of variable renewable energies must be integrated into the electricity system in a cost-efficient manner.

Many proposals on how to achieve this have been submitted in the last few months (see Schäuble, Peinl et al. 2014 for a comparison of the main proposals). The Transdisciplinary Panel on Energy Change at the Institute for Advanced Sustainability Studies has already outlined its core theses – which are presented in more detail in this study – in a policy brief (Jacobs, Schäuble et al. 2013). The proposals advanced by the Transdisciplinary Panel on Energy Change are based on three fundamental principles.

Firstly, old renewable power plants for which payment obligations have already been incurred in line with the EEG should no longer be exclusively financed through a levy but in part through an advance payment fund. Driven by the industrialisation process, the EEG has spawned innovations, which – as with other power generation technologies – should not be financed via a levy on the retail electricity price. As a result, the price of electricity would fall and the burden on households and industry would be reduced. Furthermore, this would make it clear in the public's mind that photovoltaic and wind power can already produce electricity at a cost that is comparable with new conventional power plants.

Secondly, the Renewable Energy Sources Act should be designed in such a way as to minimise the financing costs and offer as many people as possible investment opportunities in the future. The price risk should only be transferred to power plant operators if this effects a substantial change in the way power plants are operated or designed. This means that variable renewable energies (photovoltaic and wind power) have to be treated in a fundamentally different way to power plants whose output is adjustable (biomass, biogas, etc.).

Thirdly, the flexibility of the electricity system must be increased due to the rising proportion of variable technologies such as photovoltaic and wind power. Demand response should also be used for this purpose, and existing barriers to its participation in the market should be quickly removed.

The present study contains proposals for the financing of renewable energies within the EEG and for activating demand response. The proposals for refinancing old power plants through an advance payment fund are examined in a separate report. The Transdisciplinary Panel on Energy Change is proposing the following measures in order to finance renewable energies.

- Photovoltaic and wind power plants should continue to be financed through revised feed-in tariffs. These power plants have very high capital costs, no marginal fuel costs and are not adjustable (dispatchable), thereby minimising the risk premiums when financing the power plants. Moreover, it is not productive to transfer the price risks (i.e. price fluctuations on the spot market) to the producers of photo-

voltaic and wind power, as these power plants have only very limited capability to react to market prices given that power generation is dependent on weather conditions. The system can be made more flexible by combining different renewable energy technologies. Power plant operators are obliged to feed every kilowatt hour of photovoltaic and wind power generated into the grid at fixed prices. Only power plants that have never profited from regulated prices should be given the chance to use or sell the power elsewhere (e.g. for self-consumption). This will reduce the windfall effects in favour of photovoltaic and wind power plant operators (Section 3.1).

- Price regulation for photovoltaic and wind power plants should be maintained even after the twenty-year remuneration period ('golden end'). The feed-in tariff will then be reduced to the operation and maintenance costs for the photovoltaic and wind power plants that have already been written off (plus a certain margin for the power plant operator). The planned levy on self-consumed electricity should be taken into account in the process. Producers who have previously received feed-in tariffs must be obliged to feed in the wind and photovoltaic electricity they generate. Regulating the 'golden end' prevents windfall effects and allows electricity consumers to receive the economic benefits of photovoltaic and wind power plants that have been written off. In this way, photovoltaic and wind power plants could make a contribution towards financing the entire system. This arrangement could also be introduced for existing renewable power plants (Section 3.2).

- Wind and photovoltaic power sales on the wholesale market should be organised centrally. Central selling improves forecasting quality, thereby lowering the costs for balancing power and increasing security of supply. The central selling body should be able to access operators' actual feed-in data in order to improve intraday trading. The remote control of all power plants should become obligatory. If central selling proves to be impossible in the future due to possible changes in EU law on state aid, small producers could be exempted from having to sell directly by means of a so-called de minimis rule. The legislature should also allow exceptional arrangements for community-owned wind farms (Section 3.3).

The premium feed-in tariff mechanism should be used mainly for adjustable, renewable energies (e.g. biomass and biogas). The regulation should be further refined. With these technologies, the power plant operator can control the mode of operation and adapt it to the demand for electricity. This will help to balance the total amount of renewable energy fed into the grid. Power plants with adjustable outputs are in a position to optimise their revenues by reacting to market prices, which means that transferring the risk is productive in this case. The market premium payments must be complemented by capacity payments due to the relatively high capital costs and fuel costs. The conditions to be met in order to participate in the balancing market should also be simplified for power plants with adjustable outputs (Section 3.4).

- For the fixed feed-in tariff mechanism too, power plants should be curtailed in times of negative wholesale market prices (minus € 50/MWh). In this case, feed-in payments should be suspended. As the number of hours with negative wholesale prices is low, power plant operators can assume this quantity risk. On the one hand, this takes pressure from the EEG account. On the other hand, this would keep an incentive for conventional power plants to become more flexible and also adjust in times of negative market prices (Section 3.5).

- As part of the feed-in management, the curtailment of photovoltaic and wind power plants should be largely prevented by proactively expanding the grid. For example, it should be possible for the grid operator to expand the grid proactively in designated wind priority areas. If such curtailment does become necessary due to bottlenecks in the grid, the risk can be transferred to the photovoltaic and wind power plants. The volume of electricity not fed into the grid is then no longer paid for. In return, however, the remuneration period is extended by the number of hours the power plant was curtailed (20 years plus x hours) (Section 3.6).

■ A new mechanism should be put in place for determining fixed feed-in rates, and they should be set by a specialist authority on the basis of an in-depth analysis of the market and the technologies using a transparent method of calculation. The process for determining fixed feed-in rates should be organised quickly and independently. The basic principles of the EEG, on the other hand, will continue to be defined through parliamentary procedures (Section 3.7).

■ Offshore wind farms that have already applied for the relevant grid capacity with the transmission system operators, should continue to receive support through the existing EEG feed-in tariff. For all other offshore wind farms there should be a tender to determine the best level of remuneration and at the same time control the volume to be installed (Section 3.8).

■ Managing the volume of renewable energy should be integrated into more comprehensive system planning. In doing so, the optimisation objectives for controlling volumes (system costs, grid expansion, etc.) should be discussed in a transparent consultation process and portrayed in a comprehensible manner (Section 3.9).

The power output of photovoltaic and wind power plants cannot be controlled at the operator's discretion. So-called flexibility options are therefore required to cover the residual load. As well as power plants with adjustable outputs (e.g. gas-fired power plants) or energy storage systems (e.g. pumped storage power plants), flexible loads can also make an important contribution up to a certain point. Important market segments for flexible loads in Germany are the energy market (trading on the power exchange or OTC trading), the balancing market and the ordinance governing interruptible loads. The Transdisciplinary Panel on Energy Change proposes the following steps for activating flexible loads:

■ In principle, the structure of Germany's electricity spot markets is suitable for meeting the necessary degree of flexibility in the immediate future. In the short term therefore, no far-reaching changes or additional subsidy measures are needed (e.g. investment subsidy for thermal/physical storage) (Section 4.4.1).

■ The characteristics of the balancing market should be adapted to meet the needs of flexible loads in order to foster competition between supply- and demand-side options and increase the efficiency of the system. Flexible loads should start to gain experience on the balancing market to enable them to serve the balancing requirements that are likely to rise in the future. For example, the tendering period could be reduced from up to one week to one day. Furthermore, the minimum product term could be shortened from up to 24 hours to one hour (Section 4.4.2).

■ The ordinance governing interruptible loads should terminate after the three-year trial period. The ordinance represents an additional subsidising instrument for industrial loads, which is not required to meet current flexibility needs in the electricity system. Instead, the objective should be to enable competition between supply- and demand-side options. If a capacity mechanism should prove necessary in the coming years, the extent to which interruptible loads with restricted periods of use (e.g. 20 or 100 hours) can make a contribution towards securing supply in this context, should be reviewed. This review should also examine what remuneration mechanisms are appropriate for interruptible loads in this context, and whether they can be adapted to fit the cost structure of interruptible loads – low fixed costs, high variable costs. The method by which shiftable loads can be suitably integrated into capacity markets also needs to be clarified (Section 4.4.3).

■ The existing market entry barriers for independent demand response aggregators should be removed. The role of aggregators should be defined in the German Energy Act, and standard contracts and standard communications interfaces should be introduced (Section 4.4.4.1).

■ The rules for grid fees should be refined to ensure that flexible loads are not subject to excessive grid fees for taking part in the balancing market. In addition, the way in which the hours of use are calculated should be revised to ensure that participation in the balancing market does not preclude applying for reduced grid fees (Section 4.4.4.2).

1. Introduction

The energy transition in Germany is a long-term joint community project. The further expansion of renewable energies continues to enjoy the support of a broad majority of the population. Nevertheless, fundamental reform of the Renewable Energy Sources Act (EEG = Erneuerbare-Energien-Gesetz) and the design of the electricity market is required. In the last few months many studies have been published on this subject with proposals for amendments to the Renewable Energy Sources Act and the future financing of renewable energies in Germany. A comparison of these studies was presented by the Transdisciplinary Panel on Energy Change in February 2014 (Schäuble, Peinl et al. 2014). Prior to that, the Transdisciplinary Panel on Energy Change presented its core theses in a policy brief in November 2013 (Jacobs, Schäuble et al. 2013). The proposals outlined there are examined in detail in this study.

The present study details proposals for the financing of renewable energies within the EEG and for activating demand response.

The Renewable Energy Sources Act should be designed in such a way as to minimise financing costs and offer as many people as possible investment opportunities in the future. Furthermore, the flexibility of the system must be increased due to the rising proportion of variable technologies such as photovoltaic and wind power. Demand response should also be used for this purpose, and existing barriers to its participation in the market should be quickly removed.

The initial focus is on the principles and premises of financing renewable energies in Germany (Chapter 2). The following chapters will describe the proposals put forward by the Transdisciplinary Panel on Energy Change (TPEC) for financing renewable energies (Chapter 3) and for activating demand response (Chapter 4). Finally, the results are summarised, and the outlook points to the next important matters concerning the energy transition (Chapter 5).

2. Principles and premises

If Germany is to meet the target it has set itself of 80 per cent renewable electricity generation by 2050, a large share of the electricity supply will have to come from photovoltaic and wind power. The political compromise that is likely to be reached on the reform of the EEG aims the complete refinancing of renewable power plants through the electricity market as a medium-term objective. Yet this objective does not take into account the fact that even conventional power plants are currently unable to refinance themselves from revenues from existing electricity markets (energy market, balancing market, etc.).

What is more, photovoltaic and wind power plants are substantially different from other power generation technologies, and should therefore be treated differently when it comes to designing the electricity market.[1] The conventional differentiation between renewable energies and fossil-fuel generation technologies is no longer useful for designing the electricity market of the future. Important features of photovoltaic and wind power (variable supply, no marginal costs, capital-intensive) have not been taken into account in the discussions concerning EEG 2.0. The non-productive transfer of risk to the producers of photovoltaic and wind power also makes it harder to achieve the broad financial participation of consumers. The required flexibility to manage residual load in the electricity system must also be attained by adapting the demand for electricity and through power plants with adjustable outputs or energy storage.

2.1 Characteristics of photovoltaic and wind power in contrast to generating technologies with adjustable outputs

Firstly, photovoltaic and wind power depend on the weather, and what they feed into the grid fluctuates with changing weather patterns. Technically, photovoltaic and wind power plants can be controlled, but they are typically only curtailed in bottleneck situations. In contrast to adjustable power plants, the electricity generated by photovoltaic and wind power plants can only be adapted to the demand for electricity to a very limited extent.

Secondly, photovoltaic and wind power plants have almost no marginal costs. There are no fuel costs and no costs for CO_2 emissions certificates when producing electricity from sun and wind. That is why that electricity is normally dispatched first in an electricity market where the marginal costs of generation determine the market price. Given marginal costs of € 0/MWh and the very limited control options already described, these plants only respond in an extremely limited fashion to the spot market. At most, an operator would turn off his power plant for reasons of business logic in the event of negative spot market prices (see Section 3.5 on this subject). Otherwise, these plants always produce electricity when the wind blows and the sun shines – regardless of whether the price on the power exchange is € 1/MWh or € 1,000/MWh.

[1] *The following aspects also essentially apply to run-of-river hydro.*

Refinancing plants on the spot market is also much harder for technologies with no marginal costs such as photovoltaic and wind power. This effect is called the merit-order effect and it has already been analysed in many countries with a rising share of photovoltaic and wind power (Rader and Short 1998; Sáenz de Miera, Del Río González et al. 2008; Sensfuß, Ragwitz et al. 2008; Bode and Groscurth 2010). As the share of renewable energies with no marginal costs rises, the spot market price falls, and with it the revenue opportunities for these producers on the electricity market. In Germany, the so-called photovoltaic market value – in other words, the price of photovoltaic power sold on the spot market – has fallen significantly in the last few years. In 2012 the photovoltaic market value stood at 4.50 euro cents/kWh and in 2013 it was only 3.97 euro cents/kWh.[2] As the share of photovoltaic and wind power continues to rise, it can be assumed that this effect will increase. For this reason, refinancing photovoltaic and wind power plants through revenues on the spot market will also be difficult in the medium and long term.

Thirdly, photovoltaic and wind power plants are characterised by relatively high capital costs – combined with relatively low maintenance costs and no fuel costs. At the same time, they are markedly different from other electricity generating technologies. Gas-fired power plants, for example, have relatively low capital costs, relatively high maintenance costs and fuel costs that tend to be high. The costs of photovoltaic and wind power are therefore heavily dependent on capital costs (equity and borrowings). Capital generally becomes cheaper if the investment is highly secure. The success of the Renewable Energy Sources Act (EEG) is essentially due to this connection. Because photovoltaic and wind power producers can estimate their revenues for the next 20 years through the EEG, they are investing in power plants and are able to refinance them at relatively low capital costs.

In order to achieve the aims of the energy transition in Germany, large volumes of new photovoltaic and wind power plants still have to be built. There is therefore a major economic interest in keeping the financing costs as low as possible. Even slightly higher financing costs will have an effect due to the high total investment sums required to convert the electricity system. The absolute priority for photovoltaic and wind power should therefore be to keep capital costs as low as possible. This will also have the effect of lowering consumer prices.

In changing from a system with fixed feed-in tariffs to a system with floating premium feed-in tariffs and individually organised market sales, project developers and investors assume, for example, that capital costs will rise by 50 to 215 base points (Giebel and Breitschopf 2011: 26; Hern, Radov et al. 2013: 21). Even if the change is to a tendering model, it can be assumed that capital costs will rise (Grau 2014). The same applies to a change to ex ante premium payments. In deciding whether more of the price risk should be transferred to the producers of renewable energies, there is therefore a conflict of objectives between possible positive effects on the design and operation of the plant and the resulting higher financing costs.

[2] See http://www.netztransparenz.de/de/Referenzmarktwerte.htm, [last accessed on 31.03.2014].

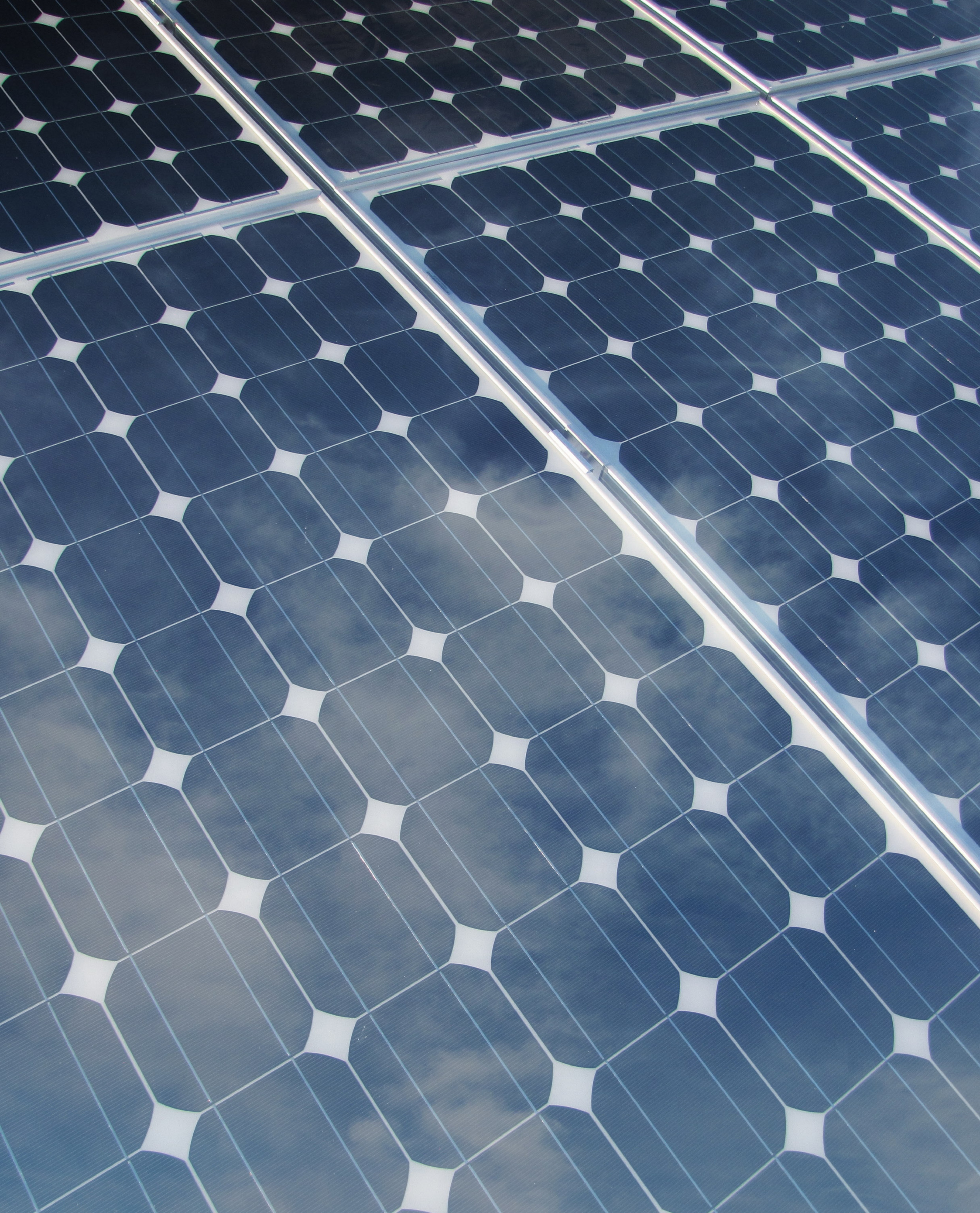
2.2 Civic participation in renewable energies in Germany

Civic financial participation in Germany is no niche market. Almost half the capacity of renewable energy installed in Germany has civic financing behind it (trend: research and Leuphana 2013). Civic participation in the financing of renewable energy does not represent added value in itself but it is a vehicle for the creation of local added value and for the acceptance of the further expansion of photovoltaic and wind power (Heinbach, Aretz et al. 2014).

In the process, it should be remembered that smaller players acting at grassroots level (private households, community-owned wind farms, energy associations, etc.) tend to have lower expectations of returns but are also more averse to risk in their investment decisions. High risks in financing power plants or in selling electricity might adversely affect such smaller players.

These factors should also be taken into account when defining European state aid guidelines for energy and the environment. The European Commission will define the new state aid guidelines by the summer of 2014 in a two-stage consultation process. The first draft of the guidelines only provides for fixed feed-in tariffs for plants with a capacity of up to one megawatt (EU Commission 2013). The ability of power producers to take on more risks in the shape of premium feed-in tariff mechanisms or tendering, does not depend on the size of the plant, however, but primarily on the structure of the operators. Small, decentralised players can also finance and operate large plants.

Just as the costs of the energy transition need to be apportioned in a socially compatible way, civic initiatives should also be given the chance to participate actively in the energy transition. For this to happen, the subsidising of renewable energy must be designed in such a way that the existing diversity of players is preserved and in particular small, decentralised players retain the opportunity to participate financially.



3. Proposals for the financing of renewable energies

The following chapter makes proposals for the financing of renewable energies on the basis of the principles and premises outlined above.[3] These proposals explore the fundamental questions of the risks to be borne by each of the players involved and which institutions are best suited to performing specific tasks.

The market integration of renewable energies is not an objective in itself, but a vehicle for better system integration. Measures towards achieving integration into the spot market should therefore be aimed at suitable, i.e. adjustable, technologies with marginal costs. The question of which generating technologies are able to respond to electricity price signals and which are not (or only to a very limited extent) must be examined. Nevertheless, we think it is possible to transfer a degree of volume risk (how many kilowatt hours can I sell at the guaranteed price?) onto wind and photovoltaic producers. Generating technologies that can control their output, on the other hand, should be confronted with the electricity price so that they can adapt the way they run their plant to the demand for electricity.

3.1 Maintaining current financing of wind and photovoltaic via revised feed-in tariffs

Currently, photovoltaic and wind power producers have the option of switching between various remuneration options (fixed feed-in tariff, premium feed-in tariff and self-consumption). This freedom of choice was originally created to help owners of photovoltaic and wind power plants to gradually familiarise themselves with the existing markets and to enable subsidies to be phased out after the technology support stage. However, as shown above, it cannot be assumed that photovoltaic and wind power plants will be able to refinance themselves on the market in the medium term. On the basis of the targets for variable renewable energies and the resulting merit-order effects, it is unlikely that power plants will be able to refinance themselves via the spot market even in the long term.

[3] *The working group for Economic and Infrastructure Policy at the Technical University of Berlin provided input to the IASS from its current work on the institutional design of the electricity sector as part of research projects sponsored by the Ministry for the Environment. This work was used to draw up the contents of this chapter. The main interim results of the project "Refining the design of the market and network regulation for the transformation of the electricity system" were made available. An initial working paper along these lines was published in February 2014. See also Becker and Hoffrichter 2014.*

The model for market integration used so far also ignores a significant advantage offered by photovoltaic and wind power: the possibility of long-term price stability. Technologies that do not use fuel have the potential to stabilise the electricity price for consumers in times of rising CO_2 emissions and fuel costs. By making it compulsory to feed in what is produced and by excluding alternative market options, 'cherry picking' is prevented and the whole system becomes cheaper. These benefits could be increased by means of rigorous price regulation and the accompanying obligation to feed in power in accordance with the terms defined. Just as a private household can stabilise its private electricity costs by producing its own electricity (predictability of an element of electricity costs for the coming decades), all electricity consumers could benefit from power generation technologies that do not require fuel.

However, if photovoltaic and wind power producers are incentivised to sell their electricity via the spot market, it will not be possible to decouple the constant (financing) costs of capital-intensive renewable energies with no marginal costs from the rising costs of conventionally generated electricity. Normally, conventional power plants set the price on the spot market and renewable energies with no marginal costs would be the beneficiaries – even if they had been previously subsidised.

That is why price regulation in the field of photovoltaic and wind power must be more rigorously implemented. Above all, optional switching between fixed feed-in tariffs and other market options should be stopped. If renewable power producers benefit from fixed feed-in tariffs and are therefore not exposed to any price risk, they should be compelled to feed all electricity into the grid for the long term in accordance with terms defined in advance. The aim should be to define rules for the entire lifetime of the plants (see also Section 3.2).

In the last few years the spot market prices for electricity have fallen sharply. This has been due primarily to falling CO_2 prices, less demand for electricity against the backdrop of economic developments in Germany and Europe, a rising proportion of renewable energy with no marginal costs, and considerable conventional excess capacity. As long as we are dealing with a relatively low wholesale price, the hindrances presented by the current approach to the market integration of renewable energies with no marginal costs are not yet obvious. With a spot market price of € 40/MWh, it could be argued, for example, that the revenues can cover the maintenance costs of an offshore wind farm.

However, it is also possible to imagine scenarios with rising spot market prices in the coming 20 to 30 years if:

- the existing excess capacity resulting from times of monopolistically organised electricity markets has been removed;

- the price of CO_2 rises sharply, e.g. as a result of the reform of the European emissions trading system or the introduction of CO_2 taxes;

- the fuel costs for gas and coal rise steeply as a result of an international shortage of resources.

If renewable power plants with no marginal costs (wind and photovoltaic) do not then cover 100 per cent of electricity demand, the market price will, for example, be set by a gas-fired power plant – with potentially high costs for CO_2 and fuel. In this case, a generation technology with very high marginal costs would be setting the price for technologies with no marginal costs at all. If photovoltaic and wind power producers are given the chance to sell their electricity through the power exchange at such times, even though they have been previously subsidised via feed-in tariffs, there could be considerable windfall effects. This would be especially the case if the legislature in Germany decides against implementing a capacity market and if the refinancing of power plants that can regulate their output is to be achieved through very volatile spot market prices.

The Transdisciplinary Panel on Energy Change proposes that photovoltaic and wind power plants should continue to be financed by revised feed-in tariffs that reflect the real power generation costs. Wind and photovoltaic power plants have very high capital costs and no marginal fuel costs, and their output cannot be regulated unless storage technologies become available.

Fixed feed-in tariffs provide a large degree of income security, thereby minimising the risk premiums when financing the plants. The overall cost of expanding renewable energies will fall as a result. Moreover, it is not productive to transfer the price risks (i.e. price fluctuations on the spot market) to the producers of photovoltaic and wind power, as these plants have only very limited capability to react to market prices given that power generation is dependent on weather conditions (only in the case of negative electricity prices, see below). The system can be made more flexible by combining different renewable energies. Power plant operators will be obliged to feed every kilowatt hour of photovoltaic and wind power generated into the grid at fixed prices. Only power plants that have never profited from regulated prices should be given the chance to use or sell the power elsewhere (e.g. for self-consumption). This will reduce the windfall effects in favour of photovoltaic and wind power plant operators.

3.2 Maintaining price regulation for the 'golden end'

In the coming decades, several hundred billion euros will be invested in photovoltaic and wind power. Investors in the power generation infrastructure are largely exempted from price risks by the Renewable Energy Act (EEG); in other words, the risk has been transferred to the consumer as a result of the EEG levy. As it is primarily a matter of refinancing capital costs with investments in photovoltaic and wind power plants, the expansion of photovoltaic and wind power can be compared with other infrastructure investments.

So the question arises: who will benefit from the 'generation infrastructure' created in the final analysis? If the price risk for the investment has been largely transferred to the final consumer, the question arises as to what happens to the plants after the end of the remuneration period when they have fully depreciated? This question is especially pertinent for photovoltaic power, as here it can be assumed that the plants will supply electricity for up to 30 years (Raugei and Frankl 2009; Breyer and Gerlach 2013). When it comes to onshore wind energy, wind power plants in locations with relatively low winds may operate for more than 20 years (Berkhout, Faulstich et al. 2013).[4]

At present, operators of renewable power plants can switch to different market options at the end of the remuneration period – and even during the twenty-year remuneration period. Producing electricity for self-consumption will become particularly attractive to photovoltaic power plants after the end of the remuneration period. The present rule (or 'non-rule') derives from the basic conviction that renewable energies should receive start-up financing via the EEG feed-in tariff mechanism ("the EEG as an instrument for the introduction of new technology"), thereby enabling them to compete on the market.

[4] In the case of wind power plants, rules governing the 'golden end' might ultimately prove to be less relevant, as even today efforts are being made to replace old power plants with more powerful wind power plants by repowering them. These steps are being taken primarily in order to make better use of very windy locations. This competition for space does not apply to photovoltaic power, however. Nevertheless, it should be borne in mind that leases are only signed for 20 years particularly for conversion areas.

However, as a result of the EEG, photovoltaic and wind power producers are exempted from the significant risks that normally apply to refinancing via the marginal cost market (price risk, volume risk, etc.). The price risk has been shifted onto the end consumer, while the power plant operator is free to choose how to sell the electricity and thereby achieve additional revenues. The aim of (price) regulation for the 'golden end' is therefore to prevent possible windfall effects and to achieve a balance between risks and benefits that is fair for the whole of society. The feed-in rate will then be reduced to the level of the operation and maintenance costs for the photovoltaic and wind power plants that will by then be fully depreciated (plus a certain margin for the power plant operator).[5] Possible charges for self-consumption should be taken into account here. The introduction of a de minimis rule for very small power plants should also be considered. As feed-in payments for the 'golden end' will probably be below revenues achievable on the spot market, the proceeds could be used to refinance old power plants via the advance payment fund.

After the twenty-year remuneration period, power plant operators will be free to choose whether to replace the existing power plant with a new one or to continue to operate the plant and feed all their electricity into the grid at the regulated feed-in rates. When regulating prices after the first 20 years, the regulator is faced with the problem of, on the one hand, creating sufficient incentives to ensure that power plants enjoy the best possible maintenance and operation, and on the other, not stopping existing power plants from being replaced by new ones that will probably be more powerful.[6]

The Transdisciplinary Panel on Energy Change proposes that price regulation be maintained for photovoltaic and wind power plants beyond the twenty-year remuneration period ('golden end'). The feed-in tariff will then be reduced to the operation and maintenance costs for the photovoltaic and wind power plants that have already been written off (plus a certain margin for the power plant operator). The planned duties for self-consumption should be taken into account in the process. The proceeds can then benefit the EEG account and can be used to finance inherited liabilities. Producers who have previously received feed-in tariffs must be obliged to feed in the wind and photovoltaic electricity they generate. Regulating the 'golden end' prevents windfall effects and allows electricity consumers to receive in the economic benefits of photovoltaic and wind power plants that have been written off. In this way, photovoltaic and wind power plants can make a contribution towards financing the entire system. This arrangement could also be introduced for existing power plants.

3.3 Centrally organised market sales of photovoltaic and wind power

The question of how to sell renewable electricity in Germany is closely linked to the discussion of different remuneration options. As part of the fixed feed-in tariff mechanism, electricity is taken by the grid operators and sold centrally by the transmission system operators. Here, the transmission system operator aggregates all EEG power plants in a balancing group, forecasts the power generation for the following day, sells this volume on the power exchange and charges the cost of any discrepancies to the EEG account.

[5] *Extending the feed-in rates for photovoltaic power plants to 30 years does not make sense, as this would probably make it harder to finance the plants. Politically speaking, it would also be hard to justify extending the remuneration period.*

[6] *This must be borne in mind particularly for wind power, where good locations are limited.*

In the case of the (sliding) premium feed-in tariff mechanism, on the other hand, power plant operators are obliged to organise market sales individually. Typically, they contract a specialised aggregator ('direct-to-market aggregator') to sell the energy on their behalf. According to the EEG draft, all power plants with a capacity of 100 kW upwards are to be obliged to organise market sales individually from 2017. A range of players and institutes are in favour of making this model compulsory (see Schäuble, Peinl et al. 2014). Finance institutes and smaller players, on the other hand, have warned of associated risks and pleaded for keeping individually organised market sales as an optional model only (BEE 2013; BEEn 2014; DGRV 2014). As regards the question of who sells photovoltaic and wind power, it should be pointed out that the product to be sold stays the same. In the future too, photovoltaic and wind power will be produced when the wind blows and the sun shines. The same marketplaces will continue to be used for both options – centrally organised market sales by the transmission system operator or individually organised market sales by an aggregator.

Unbundling regulations, i.e. the clear separation of players in the fields of power generation and transmission, is one argument against the centrally organised market sales of photovoltaic and wind power as part of the premium feed-in tariff mechanism. If the proportion of renewable energy continues to increase, the question arises as to whether the role of the transmission system operators as the sellers of renewable energy continues to make sense in view of unbundling requirements in liberalised electricity markets. After all, a substantial proportion of total power generation will then be sold by the transmission systems operators. Furthermore, centrally organised market sales could be problematic in future from the point of view of state aid. In December 2013 the European Commission presented a first draft of its guidelines for environmental subsidies for the period from 2014 to 2020.

It can also be assumed that the transmission system operators – in spite of current rules and incentives – will be sufficiently interested in selling the electricity at the best possible terms by, for example, improving the forecast for photovoltaic and wind power generation. The transmission system operators argue that they already aim to make the quality of the forecast as high as possible in order to achieve reliability of supply.

For photovoltaic and wind power plants, forecasts are subject to various stochastic factors such as the flows of local wind currents and the movement of clouds over photovoltaic power plants. The lower the accuracy of the forecast, the higher the cost of balancing energy will tend to be when running a balancing group. The quality of the forecast also depends on the size of a particular portfolio and its diversification. For example, the total EEG portfolio of a transmission system operator will tend to have higher forecasting accuracy than that of individual wind power plant operators, because the aggregation of different EEG power plants in different regional locations and weather exposure has a smoothing effect. Forecasting discrepancies cancel each other out; the total portfolio will show less deviation.

In the case of individually organised market sales, the forecasting risk is shifted to the power plant operator or direct-to-market aggregator. The uncertainty caused by deviations in actual generation or actual consumption from the forecasted figures is called the forecasting risk.[7] Direct-to-market aggregators therefore have a vested interest in making their forecasts as accurate as possible and offsetting forecasting discrepancies, for example, through continuous trading on the intraday markets.

[7] *Every operator of a balancing group in Germany is obliged to adhere to its budgeted consumption or budgeted generation on a quarter hourly basis. If the balancing group does not adhere to its budget, the transmission system operator offsets the balancing group with so-called offset energy. This can lead to costs or revenues (revenues if the incorrect supply of one balancing group exactly offsets the incorrect supply of other balancing groups, thereby automatically stabilising the supply system). In terms of financial accounting, however, it has to be assumed that offset energy constitutes an unquantifiable cost factor or, in other words, a price uncertainty, i.e. risk. Conventional power plants are therefore required to invest in reliable control and typically have high forecasting accuracy.*

The increasing risk for small players is an argument against making individually organised market sales compulsory. Individually organised market sales are associated with costs and risks for smaller power producers in particular. Firstly, the transaction costs incurred are significantly higher for small power plants. Secondly, small power producers could be more exposed to the negotiating power of a few large direct-to-market aggregators. Thirdly, making individually organised market sales compulsory could lead to the banks increasing their risk premiums, as it reduces the investment security by comparison with fixed feed-in tariffs.

Furthermore, the first signs of oligopolistic structures can already be seen in today's individually organised market sales. The natural advantages of a larger, regionally differentiated portfolio can also be seen in the market. When individually organised market sales were introduced with the premium feed-in tariff mechanism on 1 January 2011, many players initially pushed into the market, but since then their numbers have steadily dropped. Larger portfolios, led by operators of conventional power plants, proved the strongest in taking up electricity from renewable energies within the premium feed-in mechanism. As a result, today's individually organised market sales are dominated by just a few aggregators.

Large direct-to-market aggregators have an advantage over smaller direct-to-market aggregators. Similarly, a central aggregator (e.g. the transmission system operator) who bundles all photovoltaic and wind power plants has an advantage over a series of large direct sellers – even if this volume advantage becomes less with the increasing size of the portfolio. For centrally organised market sales, the present system can be maintained (selling via transmission system operators), because in practice the four transmission system operators act like one large central selling unit due to the tight selling regulations.

The Transdisciplinary Panel on Energy Change proposes therefore that the selling of photovoltaic and wind power be organised centrally. Centrally organised market sales allow higher forecasting accuracy, thereby lowering the cost of balancing and increasing reliability of supply.

In order to improve intraday trading, the central selling entity should have access to the actual feed-in data of the power plant operators. The remote control of all power plants should become obligatory. If centrally organised market sales prove to be no longer possible in the future due to possible changes in EU law on state aid, small producers could be exempted from having to sell directly by means of a so-called de minimis rule. The legislature should also allow exceptional arrangements for community-owned wind farms.

3.4 Sliding market premiums and capacity payments for renewable energies with adjustable outputs

For renewable energies with adjustable outputs, in particular biomass and biogas, confronting power plant operators with signals from the spot market is effective. The power plant operator can control power output and adapt it to the demand for electricity or the fluctuations of photovoltaic and wind power plants. Power plants that can adjust their outputs are in a position to optimise their revenues by reacting to market prices, which means that in this case transferring the price risk is useful.

The existing premium feed-in tariff mechanism should therefore be continued and expanded. Individually organised market sales thus make sense for renewable energies with adjustable outputs. In terms of the way in which the premium feed-in tariff mechanism is designed, the question arises as to whether power plant operators should only face short-term electricity price fluctuations (sliding market premium) or whether long-term changes in spot market prices should also be factored in (ex ante fixed premium). As part of the sliding market premium for adjustable renewable energies, power plant operators are incentivised to optimise the design of their plant and their mode of operation. In view of the overarching objective of steadily increasing the proportion of renewable energy, it does not seem wise to also make power plant operators deal with long-term fluctuations in the price of electricity.

However, the sliding market premiums should not be set too high, as otherwise the desired control effect of the spot market will be undermined. Given that biogas and biomass power plants are characterised, however, by relatively high, specific capital costs (€ 3,000 to 5,000/kW) and relatively high operating costs and fuel expenditure (€ 60 to 100/MWh), additional capacity payments are required in order to refinance the capital costs (Kost, Mayer et al. 2013). A lower number of full load hours in the year can also be compensated by capacity payments. Consideration should also be given to the question of whether the flexibility of biogas can be better exploited by increasingly feeding it into the gas grid. The conditions for participating in the balancing market should also be simplified for plants that can control their outputs (Gawel and Purkus 2012; see also Section 4.4.2).

The Transdisciplinary Panel on Energy Change proposes that the premium feed-in tariff mechanism should be used and refined mainly for renewable energies with adjustable outputs. With these technologies, the power plant operator can control the mode of operation and adapt it to the demand for electricity. This will help to balance the total amount of renewable energy fed into the grid. Plants with adjustable outputs are in a position to optimise their revenues by reacting to market prices, which means that transferring the risk is useful in this case. The market premium payments must be complemented by capacity payments due to the relatively high capital costs and fuel costs. The conditions to be met in order to participate in the balancing market should also be simplified for plants with adjustable outputs.

3.5 Stopping feed-in payments when spot market prices are very negative

In the past, very negative spot market prices have occurred in a few hours of the year (17 hours in 2012).[8] Negative electricity prices occur when supply exceeds demand for electricity. For example, this is the case when electricity consumption is low but generation is high, and this generation cannot be switched off. Conventional power plants with low flexibility create a 'must-run' generation in the same way as renewable energies that enjoy 'priority' under the EEG. In the current market system, these power producers can offer their electricity at negative prices, i.e. they pay money for the dispatch of their power.

As the dispatch of renewable electricity is prioritised as part of the fixed feed-in tariff mechanism, the responsible transmission system operators offer the electricity from renewable energies on the spot market in spite of negative prices in order to ensure that this electricity is dispatched first (as a result of conventional power plants' lack of flexibility).

The premium feed-in tariff mechanism already provides renewable energies with a financial incentive to switch their plants off if the negative price is below the negative market premiums. For example, this is the case for wind power at around € -50/MWh. It is doubtful as to whether this arrangement should be introduced for the fixed feed-in tariff mechanism. One argument against doing so is that negative electricity prices can have a valuable controlling effect in the electricity system and incentivise greater flexibility. In this way, operators of conventional power plants with low flexibility are given the message to upgrade their plants or even to replace them. From the climate change perspective, it is also wise to dispatch renewable electricity rather than electricity from inflexible conventional power plants even if the price is negative.[9]

[8] The term "very negative" refers here to values under the negative market premium for wind power plants, i.e. € -50/MWh and below.

[9] It should, however, be taken into consideration in this context that when conventional power plants operate at low capacity, their efficiency falls and specific emissions increase as a result.

Furthermore, higher fluctuations in electricity market prices – upwards and downwards – may lead to more flexible demand in the medium term. It can be assumed, therefore, that negative electricity prices only represent a temporary phenomenon, because more demand will be generated if prices are low or negative. The use of electricity in the heat market could play an important role, for example.

If feed-in payments to renewable power producers are maintained when prices are negative, the main effect will be to increase the financial risk for operators of inflexible, conventional power plants. This will be the case if power plant operators have to offer their electricity at even lower negative prices. The price risk is therefore transferred to the operators of inflexible, conventional power plants. Prices will fall further, thereby increasing the cost of continuing to operate these stations. There is therefore an incentive for conventional power plants to increase the flexibility of their mode of operation within the limits of technical feasibility. However, this will result in deadweight losses.

Negative electricity prices therefore become an important control factor in making the power plant portfolio more flexible. Welfare losses occur for society. It is also hard to explain in political terms why feed-in payments must be maintained for renewable energies if electricity is 'worthless'.

The Transdisciplinary Panel on Energy Change therefore proposes that generators in the fixed feed-in tariff mechanism should be curtailed when electricity prices are very negative and feed-in payments should be suspended. The power plant operators can assume this volume risk, as the number of hours with very negative electricity prices is low. On the one hand, this will benefit the EEG account. On the other, there will still be incentives in place to make conventional power plants more flexible.

3.6 Suspending feed-in payments with feed-in management and adding them back at the end

Feed-in management gives grid operators the opportunity to switch power plants off for reasons of grid stability. This currently mainly affects wind power plants in northern Germany, which have to be switched off due to grid bottlenecks. In such cases, the question arises as to whether the electricity that has not been fed into the grid still has to be paid for. The question is closely tied to that of weighing up which market player should bear the risk for grid bottlenecks. Should it be individual power plant operators or the general public, given that expansion of the grid constitutes a service to the whole of society?

At present, the feed-in management system provides for slightly reduced feed-in rates to be paid to producers of renewable energy (95 per cent of the original feed-in rate) in order to incentivise project planners (and power plant operators) to select the best possible locations from a grid perspective. If feed-in payments are further reduced or abolished as part of the feed-in management process, this would create a greater incentive to choose a location where there is security both in the short term and in the long term for feeding in the electricity.[10]

Furthermore, cancelling feed-in payments as part of feed-in management is recommended, as it is hard in political terms to justify paying for electricity that is not used. However, power plant operators only have limited ability to anticipate grid bottlenecks that might occur in the coming 20 years. Nevertheless, it can be assumed that power plant operators can bear part of the volume risk as part of the feed-in management process.

[10] One further option is to 'add back' remuneration time as suggested by the IGBCE (Mining, Chemicals and Energy Union). Hours in which the plant has to reduce its output could be added back at the end of the remuneration period. However, it should be borne in mind in this context that inflation will reduce the value of the nominal feed-in payment several years or decades later.

The Transdisciplinary Panel on Energy Change proposes that curtailing photovoltaic and wind power plants be largely prevented by means of far-sighted grid expansion. For example, in areas where wind power has priority, the grid operator should be allowed to expand the grid in anticipation of future installations. If such curtailment does become necessary due to bottlenecks in the grid, the risk can be transferred to the photovoltaic and wind power plants. The volume of electricity not fed into the grid is then no longer paid for. In return, however, the remuneration period is extended by the number of hours when capacity is limited (20 years plus x hours).

3.7 Re-institutionalising the determination of feed-in rates

Today, feed-in rates are set by amendments to the Renewable Energy Sources Act. As with any other law, the Bundestag (Federal Parliament) has the final say in determining the feed-in rate for every single technology. In concrete terms, feed-in rates are set as follows: as part of the EEG progress reports, the responsible ministry appoints research institutes to analyse the development of the technologies and the market before the scheduled amendments are made to the EEG. These research institutes then make proposals for any required adjustment of the feed-in rates. Taking these recommendations on board, the responsible ministry then draws up a paper that is passed to the federal government. The government subsequently draws up a draft bill for amending the EEG and passes it to the Bundestag. Further changes to the EEG – including changes to the feed-in rates – can then be made by the Bundestag. In the case of past amendments, final changes were also made by the Bundesrat (federal council). It is therefore a very long political path from the scientific calculation of feed-in rates by research institutes to the final determination of the feed-in rates in the Federal Law Gazette.

One argument in favour of maintaining the current procedure for determining the feed-in rates is that the EEG is a 'parliamentary law' and neither the Electricity Feed-in Act of 1990 nor the EEG of 2000 would have been achieved without the initiative of individual members of parliament. It is also doubtful as to whether the political influence would diminish if the rates were determined by other institutions. In any case, the decision-making process would be less transparent with such a procedure.

On the other hand, it can be argued that a less politically driven process could lead to results/feed-in rates that would be largely based on scientific analyses of markets and technologies. In past amendments to the EEG, it was clear that the Bundestag usually adjusted the feed-in rates for wind and photovoltaic technologies (upwards) – the technologies with the most strongly organised industrial representation.

Defining feed-in rates can no longer be seen as an instrument for managing technology – in the way that the instrument of fixed feed-in rates was debated in the 1990s and at the beginning of the twenty-first century. As can be seen from the financing framework under discussion here, price regulation for photovoltaic and wind power will continue to form an important element in shaping the German electricity market for the future. This fact should be reflected by a change in the way feed-in rates are set.

For this reason, the determination of feed-in rates should be institutionalised differently. Feed-in rates should be largely the result of a solid scientific analysis of technical data and market figures and they should be set by a specialist authority. Changes to the principles governing the support mechanism of renewable energies that go beyond determining feed-in rates should remain the preserve of parliament. By dividing responsibilities in this way, feed-in rates could also be adjusted more swiftly to take account of steep learning curves. As far as photovoltaic power is concerned, feed-in rate adjustments should be made annually along with the calculation of degression. For all other technologies it will be sufficient to make adjustments every two years.

A look at France shows that determining feed-in rates and defining the fundamental conditions for subsidising renewable energies can be done separately. There, the basic principles governing feed-in tariffs are defined in the French Energy Act, while feed-in rates are determined by decree of the responsible ministry (Jacobs 2012). Regardless of the institution that has ultimate responsibility for calculating and determining the feed-in rates (Federal Grid Agency, BMU (Ministry for the Environment), etc.), more staff should be assigned to this task as a matter of urgency in order to keep feed-in payments in line with actual generation costs.

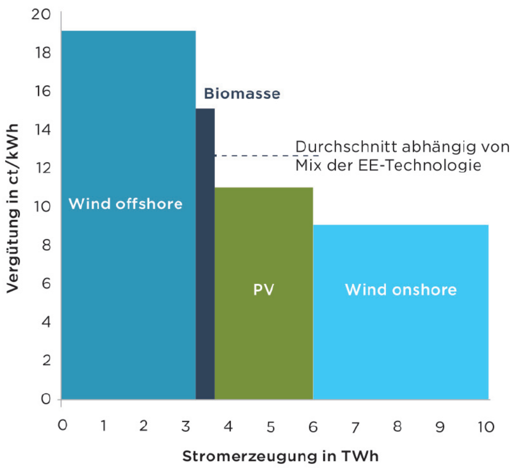
Establishing price indices can also help to depoliticise the process of setting rates. For photovoltaic power, the changes in feed-in rates should be linked to changes in the spot market prices for photovoltaic modules. On the assumption that module costs account for 30 to 50 per cent of system costs – depending on the class of power plant – at least part of the rate adjustment can become an automatic process. Furthermore, the feed-in rates should be indexed against changes in capital costs. The current low interest policy is not sustainable and capital costs are likely to rise in the future. Other indices should be examined to see if they can be used to adjust the remuneration for other technologies. Falling feed-in rates could also be an incentive for technological innovation.

The Transdisciplinary Panel on Energy Change proposes that feed-in rates should be defined by a specialist authority on the basis of an in-depth analysis of the market and technology and using a transparent method of calculation. The process for determining feed-in rates should be organised quickly and independently. The principles of the EEG, on the other hand, will continue to be defined through parliamentary procedures.

3.8 Changing to a tendering model for offshore wind energy

According to the government's current plans, offshore wind energy will cover a significant proportion of Germany's electricity supply in the future. The EEG draft paper dated 18 February 2014 states that a capacity of 6.5 GW is to be installed by 2020. By 2030 this figure is set to rise to 15 GW (SOURCE BMWi (Ministry for Economic Affairs and Energy) 2014). The comparatively high feed-in rates and large volumes of offshore wind power will mean considerable costs for electricity consumers.

FIG 1: EEG REMUNERATION STRUCTURE FOR NEW PLANTS IN 2015



Source: (BMWi 2014)

Vergütung in ct/kWh = Feed-in rate in ct/kWh
Durchschnitt abhängig von Mix der EE-Technologie = Average dependent on mix of renewables
Stromerzeugung in TWh = Electricity generation in TWh
Biomasse = Biomass

The feed-in rates for offshore wind energy have been subject to continuous upward revision in previous EEG amendments, as development of this still young and relatively risky technology has proved more expensive than expected. The price risk for offshore wind energy is also transferred to the consumer via the EEG levy. Alternatives should be examined in order to prevent the EEG levy from rising further. For example, costs that exceed a certain threshold (e.g. 10 euro cents/kWh) could be covered by a fund.

The question also arises as to whether current feed-in rates match the generation costs of this still new technology or whether cost reductions can be achieved through competitively determined prices. In the case of competitive tendering models, renewable power producers bear a higher risk than they do in the feed-in mechanisms. The increased risk is primarily a result of the uncertainty as to whether the relevant bid will be selected (usually in euro cents per kilowatt hour) and the project can therefore go ahead. The risk therefore is mainly connected to project development. There are also higher administrative costs (participation in tender, preparation of bids, etc.).

Several factors favour a change of support mechanism in the field of offshore wind energy. Offshore wind energy is a comparatively new technology. There are therefore few comparative figures available as far as technology costs are concerned. Germany and Great Britain are the only markets in which offshore wind farms are being built to any notable degree. But even these two markets are only comparable to a certain extent (different funding mechanisms and different water depths/distances from the coast). In the case of new technologies, it is harder for lawmakers to fix feed-in rates by administrative means (assumptions with regard to plant costs, maintenance costs, etc.). There is therefore considerable information asymmetry between the offshore industry and the political decision-makers who fix the feed-in rates (Lesser and Su 2008).

In the past, feed-in rates for other technologies were also estimated and revised in a process of trial and error. This was the case, for example, with wind power in the 1990s or photovoltaic power in the early 2000s. However, in those cases, relatively small volumes of electricity were involved in contrast with the growth in offshore wind energy budgeted for. If the feed-in rates for offshore wind energy are set only slightly higher than necessary, this could result in considerable extra costs for the consumer.

The structure of the parties involved is one argument in favour of tendering when it comes to offshore wind energy. The development of offshore wind farms is very capital intensive and is therefore being undertaken by large energy companies or international project developers. Here, the heterogeneity of players typical of the energy transition in Germany is nowhere to be seen. Furthermore, the transaction costs incurred in tendering can be justified for projects with investment costs of several hundred million euros.

Introducing tendering in the field of offshore wind energy could establish ‘competition for the market’. As the original targets for offshore expansion have now been challenged by many parties, it will be necessary to control the build-up in the medium term. The additional volumes could be controlled by means of a tendering model in the area of offshore wind energy.

However, there are a several important arguments against the introduction of a tendering model for offshore wind energy. The political discussion surrounding a system change could delay investment and thereby slow down the expansion. Furthermore, the projects that are already in the planning and construction stages have secured their finance on the basis of the defined feed-in rates.

The Transdisciplinary Panel on Energy Change proposes that offshore wind farms that have already applied for the relevant grid capacity from the transmission system operators should continue to be financed through the existing EEG feed-in tariff mechanism. For all other offshore wind farms there should be a tender to determine the best level of remuneration and at the same time control the volume to be installed.

3.9 Integrating volume control of renewable energies into system planning

There is increasing unanimity in the scientific and political debate that the future German electricity system will be dominated by the supply-dependent generation technologies of photovoltaic and wind power (Leprich, Hauser et al. 2012; Nitsch and Pregger 2012). As photovoltaic and wind power plants with fixed feed-in rates are not subject to price signals on the spot market, the legislature should concern itself more closely with system planning and feed-in rates. The need to do so arises not only in connection with fixed feed-in tariff mechanism but also with sliding market premiums and tenders. A certain degree of system planning will be required in any case to create the optimum systemic combination of wind power, photovoltaic power and technologies with adjustable outputs.[11]

The draft paper for EEG 2014 defines expansion targets for the proportions of renewable energies in 2025 and 2035. The instruments used so far to control the volumes of the different technologies are sufficient, but they are mainly based on the view that supporting the cheapest technologies should be the primary focus (flexible cap of 2.5 GW for photovoltaic and onshore wind power; binding volume control for offshore wind; control via adjustments to remuneration/degression) (BMWi 2014). In this context, the cap on supporting photovoltaic power at 52 GW should be lifted.

However, as well as looking at generation costs, in the medium term system planning should also consider aspects such as system stability, optimisation objectives for the expansion of different technologies, the import and export of electricity, and other factors. System planning should be institutionally prepared in the coming years. The decision-making process should be made as transparent as possible and organised in the form of a consultation process – similar to the way the grid development plan was drawn up by the Federal Grid Agency (BNetzA).

To be able to meet the demand for electricity to a large extent from variable renewable energies, Germany needs total installed capacity (consisting of technologies with and without adjustable outputs) far in excess of the maximum demand for electricity. The 70 GW of wind and photovoltaic capacity installed today is already close to the maximum demand of 85 GW. Total installed capacity in Germany is around 175 GW.[12] Therefore, a considerable amount of wind and photovoltaic capacity must be added in order to meet the government's targets.

The importance of having such a transparent procedure for determining the volumes required becomes clear when we compare scenarios for Germany and Europe. The relevant studies normally reflect the government's long-term energy objectives. Nevertheless, the scenarios are very different, for example, with regard to the number of sectors considered, the targets for renewable energies, or the opportunities for the cross-border exchange of electricity. The secured capacity assumed for each generation technology as well as meteorological and socio-economic conditions in Germany also differ considerably between studies. The total amount of installed capacity for wind (onshore and offshore) and photovoltaic for 100 per cent supply of electricity from renewables by 2050 in Germany varies from 97.8 to 537 GW (see Table 1).

[11] *Controlling the volume of photovoltaic and wind power added through the electricity price does not appear to be a constructive alternative, as the merit order effect already seen today would be reinforced by the increasing simultaneity of feed-ins.*

[12] *List of power plants, Federal Grid Agency, www.bundesnetzagentur.de [last accessed on 31.03.2014].*

TABLE 1: ENERGY SCENARIOS FOR GERMANY

Studies	Proportion of renewable energy and year	Installed onshore wind capacity	Installed offshore wind capacity	Installed photovoltaic capacity	Assumptions regarding increases in energy efficiency	Imports of renewable energy
Fraunhofer ISE (Henning and Palzer 2012)	100% (electricity, heat and transport) in 2050	200 GW	85 GW	252 GW	Heat requirements in building sector 65% of 2010 level	Germany self-sufficient
EWI/GWS/Prognos (Schlesinger, Lindenberger et al. 2010)Scenario II A	At least 50% of primary energy consumption from renewables by 2050	36 GW	28 GW	39 GW	Reduction in primary energy consumption of 1.7% p.a. by 2050; Reduction in gross demand for electricity of 25.2% by 2050	70.8 TWh (15.4% gross electricity consumption)
DLR/Fraunhofer IWES/ IfnE (Nitsch, Pregger et al. 2012)Scenario 2011 A	85% in the electricity sector and 52% of primary energy consumption by 2050	50 GW	32 GW	67 GW	Reduction in final consumption of electricity of 24% to 393 TWh by 2050	61.9 TWh import of renewables (13% of renewable power generation)
UBA (Klaus, Vollmer et al. 2010) Scenario: association of regions	100% electricity by 2050	60 GW	45 GW	120 GW	Reduction in final energy consumption of 58% by 2050	23 TWh renewable electricity imports (5% of electricity consumption)
EWI (EWI 2011) Scenario A	80% renewable electricity by 2050	47.3 GW	10.2 GW	0 GW	Growth in demand for electricity between 0-0.7% per decade until 2050	43% imports (renewables + conventional) of electricity demand
SRU (SRU 2011) Scenario 2.2 a: Association D/ DK/NO	100 % electricity by 2050	24.6 GW	73.2 GW	0 GW	509 TWh net electricity consumption	15% net imports from DK/ NO
BNetzA (BNetzA 2013) Scenario B2024	2024, no details of proportion of renewable electricity	50.4 GW	12.8 GW	58.3 GW	Final energy consumption and maximum load for year at the level of 2011 assumed to be constant	Expansion of import capacity of border interconnectors of almost 50% by 2024 (17,300 ->25,600 MW)

Source: own chart

The following questions must therefore be answered in relation to controlling the volume of photovoltaic and wind power and system planning:

- What optimisation objectives are to be used when defining volumes for photovoltaic, onshore wind and offshore wind (e.g. system costs, expansion of grid, consumer costs, acceptance, etc.)? What role will energy efficiency play?
- What assumptions are to be made with regard to imports and exports of electricity?
- What organisation is to control volumes? Who is responsible for developing scenarios (e.g. BNetzA, etc.)?
- How will limited capacity be allocated (e.g. on a first come, first served basis or via tenders)?

The Transdisciplinary Panel on Energy Change proposes that the volume control of renewable energies should be integrated into system planning. Optimisation objectives for volume control (system costs, grid expansion, etc.) should be openly discussed in a consultation process and explained in a transparent manner.

4. Proposals for enabling demand response

4.1 Residual load and flexibility of Germany's electricity system

The Transdisciplinary Panel on Energy Change recommends that the regulation of weather-dependent generation plants (photovoltaic and wind power) with a high proportion of capital costs should be fundamentally different from the regulation of generation plants with adjustable power output and a significant proportion of variable costs (coal, gas, biogas and biomass). As the power output of wind energy and photovoltaics cannot be controlled at will and power plants can therefore only respond to price signals to a limited degree, the remaining energy system must be adapted to integrate these two leading technologies. This makes the use of flexibility options all the more important when it comes to the future electricity market. For this, a regulatory framework is required that makes the most of the flexibility potential inherent in existing resources – particularly on the demand side – and incentivises the appropriate technical features.

4.2 Need for flexibility as a result of photovoltaic and wind power

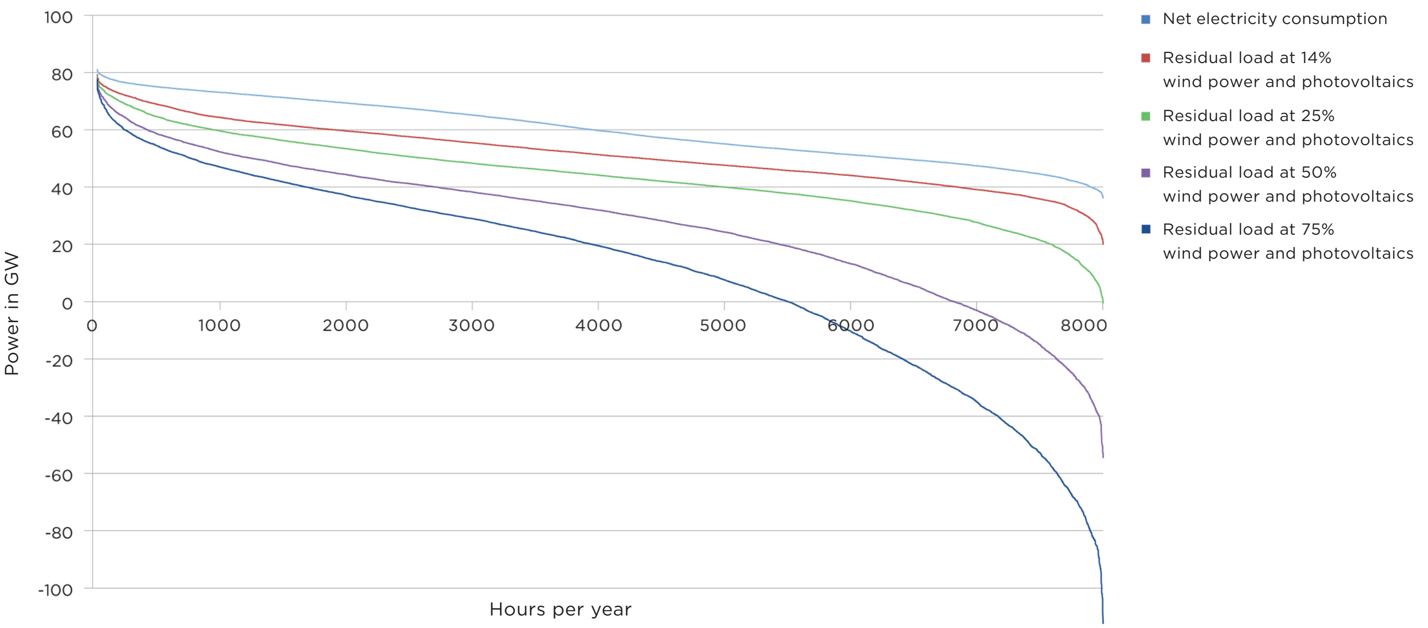
The very low variable costs of photovoltaic and wind power mean that generation plants with controllable output and high variable costs will no longer meet the total demand but only the residual load (net electricity consumption minus generation from photovoltaic and wind power). New flexibility options will be needed in the future to provide sufficiently secure capacity and integrate temporary generation surpluses into the electricity system. The technical characteristics of such flexibility options (e.g. power gradients) will play a more important role in the future as a complement to the variable generation of photovoltaic and wind power.

The reserve capacity required and its annual usage duration are shown in Fig. 2. The upper curve represents net electricity consumption. In 2012, 14 per cent of net electricity consumption was covered by photovoltaic and wind power. The requirement for generation plants with adjustable outputs fell by an average of 8 GW as a result. The absolute peak residual load only fell by 2 GW, however. That means that generation plants with adjustable outputs have to provide more or less the same capacity, but their operating time is considerably reduced. If the expansion of photovoltaics and wind power continues, operating times will fall even further. If photovoltaic and wind power reach a proportion of 50 per cent, capacity in the double-digit gigawatt range would be required with operating times of less than 100 hours per year.

The graph also shows that around 25 per cent of net electricity consumption covered by photovoltaic and wind power already results in negative residual load with the result that further flexibility options will be required to integrate this 'surplus electricity' sensibly. At a proportion of 50 per cent, the residual load may be less than -50 GW in individual hours. However, it makes economic sense to curtail photovoltaic and wind power plants to a certain extent.

Primarily, these surpluses require flexibility options that can absorb them on an hourly basis (Schill 2013). Additional surpluses may occur if conventional power plants have must-run obligations.

FIG 2: ESTIMATE OF RESIDUAL LOAD GROWTH IN GERMANY



Source: IASS on the basis of load data from ENTSO-E; wind and PV feed-in data from 50Hertz, Amprion, TenneT and TransnetBW

For example, this may be the case if combined heat and power plants are operated in heat-controlled mode or if conventional power plants are needed for system services such as balancing reserves.

4.3 Flexibility options and the role of demand reponse

In addition to conventional power plants, further flexibility options can be utilised to meet the need for flexibility. These options may bring technical, financial and ecological benefits. Their suitability is discussed in the following paragraphs (BMU 2012).

4.3.1 Grids, thermal power plants and energy storage

The balancing requirements can be reduced by expanding national transmission grids and the interconnectors with neighbouring countries, and they can be met with a variety of resources. As a result, the efficiency of the electricity system will improve, as the fluctuations of photovoltaic and wind power are not offset locally (e.g. in-house battery storage) but by wind power and photovoltaic plants in other regions or by more convenient flexibility options (e.g. pumped storage or adjustable power plants).

Thermal power plants can and will also meet part of the need for flexibility. Single-cycle gas-turbine power plants, in particular, (with no heat coupling) can be used to follow high power gradients. Of all thermal power plants, they represent the most financially attractive option for covering peak load times. With a hot start (shutdown < eight hours), gas-fired power plants can reach their rated capacity within a few minutes and in this way compensate for any forecasting inaccuracies. Thermal power plants will also be needed in the coming decades to provide secure power. At present they are also needed to provide system services such as balancing reserve power. In this task they usually have the disadvantage of having to be continuously on the grid at part load. The resulting must-run capacity may result in a further increase in surpluses in the German electricity system.

Energy storage systems can also meet an important part of the described need for flexibility from a technical viewpoint if they are designed and operated to match the particular area of application. For example, the fast reaction time of accumulators (e.g. lithium-ion accumulators) can be used to compensate fluctuations by the second or even to reflect the inertia of rotating masses ('momentary reserve'). Pumped storage power plants, which at present represent the cheapest energy storage technology, can be used for a storage length of several hours, and can also provide a significant proportion of the required balancing power. And lastly, the conversion of surplus electricity from renewable sources into hydrogen or methane could help to offset longer-lasting surpluses and deficits of several weeks. This latter option will only make sense and be needed, however, if the proportion of renewable energy is very high.

4.3.2 Flexible loads (demand response)

In addition to these options, flexible loads can also play a central role in balancing generation and demand. So instead of increasing power output, demand can be reduced and vice versa. Flexible loads are loads that can react to market price signals or can be dispatched by the transmission system operator as part of a contractual power reserve (e.g. balancing reserves). Suitable processes and applications can be found in industry (e.g. cement mills), in commerce (e.g. refrigeration of food) and in households (e.g. heat pumps) (Apel, Aundrup et al. 2012; Klobasa, von Roon et al. 2013). The specific characteristics of the loads determine what role they play in the electricity system. The characteristics of flexible loads differ according to whether the load is able to provide negative and/or positive power and whether a storage system (e.g. thermal) is available on the demand side. Table 2 outlines the three types of flexible loads that arise from these differences.

Load shifting is possible if physical (e.g. wood storage), thermal (e.g. heat and cold storage) or chemical (e.g. hydrogen) storage systems that fulfil a similar function to electrical energy storage systems can be used on the demand side. The possible duration and frequency of load shifting depends on the process involved. Crucial parameters include the size of the storage and the reserve capacity of the system. The advantage of using storage systems on the demand side is that process interruptions have no negative effect on the subsequent production process and do not affect comfort. In practice, there are flexible loads that enable load shifting by the minute or hour. This means that a variety of functions can be performed, which can also be provided by electrical power storage systems such as a pumped storage power plant.

If no storage system is available on the demand side, a **load shedding** is still possible in many cases. For example, the temperature of the thermostat can be reduced (electric heating with a heat pump) and industrial processes can be halted. A large proportion of the existing demand response potential that, for example, is exploited in various energy markets in the USA, belongs in this category. Due to associated production losses or reductions in comfort levels, sheddable loads can only be used if application times are very limited. Accordingly, such applications are typically used as an emergency reserve for up to thirty hours a year.

Hybrid heating systems for district heat networks, where an electrical heating rod or a heat pump generates heat at times when market prices are low or negative, can be used to **increase loads**.

TABLE 2: TYPES OF FLEXIBLE LOADS WITH EXAMPLES FROM THE HEATING SECTOR

Type	Power	Storage	Application example
Load shifting	Positive and negative	Yes	During low-price times an oversized heat pump charges a thermal storage system, which provides the required heat during high-price periods
Load shedding	Positive	No	In high-price periods the heat pump is temporarily halted. As a result, the room temperature falls and comfort is compromised.
Load increase	Negative	No	Normally, a gas boiler is used to provide heat, but at times when prices are low, an electrical heating rod takes over.

Source: IASS Potsdam

4.4 The structure of German electricity market and its suitability for demand response

In Germany, there are various markets and instruments available for balancing generation and demand. These include the energy market, the balancing market, the ordinance governing reserve power plants and the ordinance governing interruptible loads. This structure is shown in Table 3.

Incentives for activating flexible loads can be created via the energy market (day-ahead or intraday), the balancing market or the ordinance governing interruptible loads. The next three paragraphs explain how these markets or instruments work and describe their suitability for flexible loads.

4.4.1 Spot market (day-ahead, intraday)

Electrical energy for planned consumption and generation can be traded on the spot market. The European trading platform European Power Exchange (EPEX SPOT) provides the day-ahead market and the intraday market for this purpose. Price fluctuations can create incentives to reduce, increase or shift power consumption on a temporary basis.

4.4.1.1 Design characteristics of the day-ahead and intraday markets

On the day-ahead market, trading is conducted for planned generation and consumption on the following day on the basis of 24 intervals of one hour each. Hourly products (e.g. for hour 18) and blocks (e.g. peak load for hours 9 to 20) are offered for trading. The auction is conducted at 12 noon of the day prior to physical dispatch. The price of a megawatt hour is determined by the highest bid needed to cover demand (market clearing price). Typically, this will be equivalent to the marginal costs of the most expensive power plant used.

If further trades are required after 12 noon of the previous day, the intraday market, which opens at 3 p.m. on the previous day, can be used. The minimum lead time before physical dispatch is 45 minutes. Hourly products and quarter-hourly products are offered as trades. The price is established using the pay-as-bid principle. According to this principle, successful bids are paid at the price offered.

TABLE 3: STRUCTURE OF THE GERMAN ELECTRICITY MARKET

Balancing residual load		Redispatch when grid congestions occur
Energy market OTC market Power exchange • Future market • Spot market	Balancing market Primary reserve Secondary reserve Tertiary reserve	Ordinance governing reserve power plants
Ordinance governing interruptible loads		

Source: IASS Potsdam

TABLE 4: CHARACTERISTICS OF DAY-AHEAD AND INTRADAY MARKETS

	Day-Ahead	Intraday
Trading period	12 noon on the day prior to physical dispatch	Up to 45 mins before physical dispatch
Trading products	Single hours, blocks of hours	Single hours, 15 minute blocks
Pricing	Unified price auction	Pay-as-bid auction

Source: IASS Potsdam

Flexible loads can be used on the day-ahead and intraday markets in order to optimise the dispatch of electricity. As the proportion of photovoltaic and wind power rises, the price fluctuations on these markets may increase and create corresponding incentives for flexible loads. Table 5 shows how the three types of flexible loads react to different price constellations.

To ensure that **load shifting** is offered for significant volumes of energy, large price spreads (e.g. EUR 50/MWh between single hours) have to occur relatively frequently on the spot market. It is also necessary for the electricity providers to pass these price signals on to the end users, for example, by way of time-of-use pricing (e.g. day and night tariffs) or real-time pricing (e.g. directly dependent on day-ahead market). The potential revenues from load shifting must be sufficiently high to cover the variable costs (e.g. efficiency losses) and the fixed costs (e.g. depreciation, capital costs).

Load shedding becomes financially attractive if extremely high temporary prices (e.g. > EUR 1,000/MWh occur on the spot market. As well as real time tariffs, the so-called critical peak load tariff can also be used. This consists, for example, of a low basic tariff and an event-based peak load tariff that is triggered by very high prices on the day-ahead market. The resulting savings must be sufficient to compensate for the loss of production or reduced levels of comfort. The variable costs are typically very high, but the fixed costs are low.

Increasing the load can be economical if prices temporarily fall below a certain threshold (e.g. < EUR 10/MWh) and electricity-intensive processes become economical as a result.

For example, in a hybrid heating system, an electric boiler can take over heat generation when prices are very low, thereby reducing the consumption of gas. The savings must be sufficiently high to cover the additional fixed costs (e.g. depreciation, capital costs, etc.).

4.4.1.2 International experience

On several electricity markets, electricity providers have designed flexible tariff systems to pass on market price fluctuations to consumers. For example, electricity companies in California offer the peak load tariffs already mentioned with the aim of reducing the system load on days with high demand. In energy markets such as PJM (Pennsylvania, New Jersey, Maryland) or New York, additional programmes have been implemented in order to create an incentive for consumers to reduce their power consumption at peak times. These additional programmes were created for a context where many consumers still procure their electricity through uniform tariffs (Monitoring Analytics 2013). The independent system operator in New York, for example, has introduced the so-called day-ahead demand response programme. Consumers can make an offer on the day-ahead market to reduce their power consumption on the following day. If the price of electricity is over USD 75/MWh and the offer is accepted, consumers are obliged to honour their offer (NYISO 2013). Experience has shown that participation in such programmes and effects on consumer behaviour are relatively low, and only niche applications react to the market price. This could have to do with the fact that market prices, as in Germany, do not reach the dimensions required to cover the opportunity costs of interruptible loads.

TABLE 5: INCENTIVE MECHANISMS FOR FLEXIBLE LOADS ON DAY-AHEAD AND INTRADAY MARKETS

Type	Incentives via
Load shifting	Regular price spreads (e.g. > EUR 50/MWh)
Load shedding	Occasional, very high prices (e.g. > EUR 1,000/MWh)
Load increase	Regular low prices (e.g. < EUR 10/MWh)

Source: IASS Potsdam on the basis of Gobmaier and von Roon 2010

4.4.1.3 Assessment and recommendations

High price fluctuations on the day-ahead and intraday markets are to be expected as a result of the further expansion of photovoltaic and wind power. When and if these price fluctuations will be enough to provide secure flows of income for the operators of flexible loads, is still not clear. If the price fluctuations prove to be insufficient, accompanying measures (e.g. investment subsidies for thermal/physical storage) could be helpful.

The Transdisciplinary Panel on Energy Change believes that the structure of the spot markets is suited in principle to meeting the need for flexibility in the near future. In the short term therefore, no far-reaching changes or additional subsidy measures are needed (e.g. investment subsidy for thermal/physical storage).

4.4.2 Balancing reserve market

Balancing power is needed to maintain frequency stability in the German electricity system. The transmission system operators auction primary reserve, secondary reserve and tertiary reserve, which differ from each other in their activation times (30 seconds, 5 minutes and 15 minutes) among other things. Successful bids are paid a clearing price for keeping electrical power in reserve. If the power is required, an additional energy price is paid for the secondary and tertiary reserve only. Reserve power is typically offered by conventional power plants and pumped storage plants. A small proportion, however, is already provided via flexible loads.

TABLE 6: CHARACTERISTICS OF THE SECONDARY AND TERTIARY RESERVE

	Secondary reserve	Tertiary reserve
Response time	5 minutes	15 minutes
Positive/negative power	Positive or negative power	Positive or negative power
Smallest possible length of offer	7 days with 12 hours per day	One block of 4 hours
Availability within offer period	100 per cent	100 per cent
Maximum switch-off frequency within offer period	No restrictions	No restrictions
Voltage level	No restrictions	No restrictions
Minimum power	5 MW	5 MW
Pooling of loads	No restrictions within one balancing area	No restrictions within one balancing area
Maximum continuous length of switch-off	12 hours	4 hours
Remuneration	Clearing price and energy price (result of an auction using pay-as-bid procedure)	Clearing price and energy price (result of an auction using pay-as-bid procedure)

Source: IASS Potsdam

4.4.2.1 Design characteristics of the balancing market

The main design characteristics of the balancing market are shown in Table 6 using the example of the secondary and tertiary reserve[13]. Flexible loads must be able to provide 100 per cent of the contractually agreed power for the offer period of seven days with twelve hours each (secondary reserve) or four hours per day (tertiary reserve) . Suppliers of tertiary and secondary reserves must be able to supply at least 5 MW. These 5 MW can be achieved by bundling flexible loads, e.g. ten consumers with 500 kW each.

4.4.2.2 International experience

In various markets in the USA, flexible loads can already take part in the balancing market. In the product segments called 'spinning reserve' (PJM) or 'response reserve' (ERCOT), which roughly correspond to the German tertiary reserve in terms of their response times, flexible loads offer up to fifty per cent of the tendered power. Comparisons with the German market are only possible to a very limited degree due to differences in the market structure and the targeted application. For example, in the PJM electricity market, the so called 'spinning reserve' was only used up to 36 times per year from 2009 to 2012. The duration was always under 45 minutes and added up to around nine hours for the year (Monitoring Analytics 2013). The frequency of use in the ERCOT electricity market is also very low, and interruptible loads were activated no more than six times per year from 2006 to 2011. By comparison, the positive tertiary reserve in Germany is used significantly more often. Ten per cent of the tendered power is in use in approx. 1,000 h/year, and even eighty per cent of the positive tertiary reserve is used in 70 h/year.

4.4.2.3 Assessment and recommendations

The design of the balancing market is in part tailored to the characteristics of conventional power plants with the result that there are entry barriers for flexible loads. This makes it impossible to have fair competition between supply-side and demand-side options. In particular, the smallest possible offer time of seven days with twelve hours per day for the secondary reserve must be gradually reduced, as most flexible loads are not able to guarantee this performance either seven days in advance or twelve hours in succession. In order to capitalise on the potential of flexible loads, the Transdisciplinary Panel on Energy Change sees an offer time of one hour for the secondary and tertiary reserves as sensible. Tendering should always take place on the day before.

Flexible loads are one of several ways to reduce the proportion of power plants required to run synchronously on the grid (must-run capacity). This advantage will play an important part in the future German electricity system. However, there is no further flexibility need for the current proportion of photovoltaic and wind energy, with the result that no additional support schemes are required at present (e.g. minimum quota for interruptible loads, floor price for interruptible loads). Nevertheless, the barriers mentioned should be removed not only to improve efficiency, but also to gain experience in handling demand response, which will be more import in the future.

The Transdisciplinary Panel on Energy Change proposes that the characteristics of the balancing market should be adapted to meet the needs of flexible loads in order to foster competition between supply-side and demand-side options and increase the efficiency of the system. Flexible loads should start to be used on the balancing market to enable them to fulfil balancing requirements that are expected to rise in the future. For example, the tendering period can be continuously reduced from up to one week to one day. Furthermore, the minimum product term can be shortened from up to 24 hours to one hour.

[13] In this study, the primary reserve is not viewed separately as the Transdisciplinary Panel on Energy Change assumes that this segment of the market tends to be more suited to electrical storage systems due to the technical requirements involved.

4.4.3 Ordinance governing interruptible loads (AbLaV)

The ordinance governing interruptible loads requires transmission system operators to put 1.5 GW of immediately interruptible loads (SOL) and a further 1.5 GW of quickly interruptible loads (SNL) out to tender. In a similar way to reserve power, the transmission system operators can use these loads to maintain frequency. It is also conceivable to use these loads for redispatch measures or for financial purposes in the event of high spot market prices.

4.4.3.1 Design characteristics of the ordinance governing interruptible loads

The ordinance governing interruptible loads defines two product groups. The response times for immediately interruptible loads and quickly interruptible loads are one second and fifteen minutes respectively.

Three further sub-products are also defined depending on the maximum possible length of interruption. Prequalification is required to take part in the tender for these products. As well as the response time and length of interruption, the ordinance defines further technical criteria that interruptible loads must meet. These are shown in Table 8.

Interruptible loads that take part successfully in the monthly tender can expect fixed remuneration of EUR 2,500/MW per month. They will also receive an energy price of EUR 100 to 400/MWh for an interruption.

TABLE 7: PRODUCT GROUPS FOR ORDINANCE GOVERNING INTERRUPTIBLE LOADS

	Immediately interruptible loads			Quickly interruptible loads		
Response time	1 second			15 minutes		
Maximum length of interruption in succession	1 h	4 h	8 h	1 h	4 h	8 h

Source: IASS Potsdam

TABLE 8: CHARACTERISTICS OF SOL AND SNL PRODUCT GROUPS

Positive/negative power	Only use positive power (load reduction)
Voltage level	>= 110kV
Minimum power	50 MW
Pooling of loads	Max. 5 in effective area of transmission node
Smallest possible bid time	One calendar month with no time restrictions
Availability within bid time	Less than 100% availability tolerated on 4 days a month, whereby a break of one minute already counts as non-availability
Maximum interruption frequency within bid time	Max. 16 hours per month (plus product-specific minimum breaks after an interruption)

Source: IASS Potsdam

4.4.3.2 International experience

Demand response programmes similar to the ordinance governing interruptible loads have already been implemented in many electricity markets in the USA. These programmes exist in electricity markets with a central capacity market (e.g. PJM and New England), in bilateral capacity markets (e.g. California), and in markets with no capacity payments for power plants (e.g. ERCOT). What these programmes have in common is that interruptible loads are used as an emergency reserve and their length of use normally does not exceed 20 hours per year. The mechanism for defining remuneration and other parameters in the demand response programmes such as response time, minimum availability, maximum length of interruption in one session, and smallest possible bid time are determined individually by the local regulatory authorities, and they differ widely as a result. Experience shows that these emergency programmes have the greatest financial significance for interruptible loads internationally (Hurley, Peterson et al. 2013)

4.4.3.3 Assessment and recommendations

The interruptible loads contracted by the ordinance governing interruptible loads could be used for redispatch measures, as an alternative to the positive tertiary reserve, and for financial purposes when spot market prices are high. Given these differing objectives, the design of the ordinance is inconsistent, and the question arises as to what system benefit the ordinance offers.

Redispatch measures are carried out to prevent congestions in the transmission grid. Grid areas frequently affected include the Remptendorf-Redwitz North-South connection, which connects the 50Hertz grid with that of TenneT. A total of 983 redispatch measures were taken in the 2012/2013 winter (BNetzA 2013). However, the ordinance only allows load reduction in 16 hours a month. The ordinance also contains no regional component, for example, a focus on southern Germany and other regions affected by redispatch measures. As a result, in its current form the ordinance is only partially suited to redispatch measures. The question of whether demand response is generally suited to redispatch measures also needs to be examined.

Contracted interruptible loads could be used as an alternative to balancing power, specifically the positive tertiary reserve. There are several inconsistencies here. On the one hand, the fact that the balancing market is not used to increase reserves is questionable. On the other hand, the question arises as to why only one product similar to the positive tertiary reserve is subsidised, while others like the negative tertiary reserve or the positive/negative secondary reserve are not. Thirdly, many parameters from the regulation represent a considerable step backwards from the market design for the tertiary reserve. For example, the obligation to provide power applies for a whole month instead of for four hours per day. There are also heavy restrictions with regard to the minimum size and the connection point (voltage level). These prequalification criteria only allow a few industrial companies to participate.

The Transdisciplinary Panel on Energy Change proposes that the ordinance governing interruptible loads should be wound up after the three-year trial period. The ordinance represents an additional subsidising instrument for industrial loads, which is not required to meet current flexibility needs in the electricity system. Instead, the objective should be to allow competition between supply-side and demand-side options (see Section 4.4.2 Balancing market, for example).

If a capacity instrument should prove necessary in the coming years, the degree to which interruptible loads with limited periods of use (e.g. 20 or 100 hours) can make a contribution towards security of supply within this framework, needs to be reviewed. This review should also examine what remuneration mechanisms are appropriate for interruptible loads in this context and whether they can be adapted to fit the cost structure of interruptible loads – low fixed costs, high variable costs. The question of how shiftable loads can be suitably integrated into capacity markets should also be clarified.

4.4.4 Further regulatory conditions for participation in markets

The participation of companies with flexible loads in the markets described also depends on the overriding regulatory framework as well as the specific requirements of any particular market.

4.4.4.1 Aggregators

Companies with flexible loads are dependent on so-called aggregators, which bundle many different loads and offer them in accordance with market requirements. As intermediaries, aggregators form the necessary interface between the players in the liberalised electricity market (balancing group manager, electricity traders, transmission system operators and distribution network operators) and take on the operational management of interruptible loads. At present, demand response aggregators require individual contracts with these players for which there are no standard rules or contractual obligations. This slows down the speed of any possible innovations and makes a positive contractual outcome less likely.

The Transdisciplinary Panel on Energy Change proposes that the existing barriers to entering the market should be reduced for independent aggregators. The role of aggregators should be defined in the German Energy Act (EnWG), and standard contracts and standard communication interfaces should be introduced.

4.4.4.2 Grid fees

When flexible loads are used in the balancing market or on the spot market, the effects on grid fees must be taken into consideration. Adding loads, in particular, can cause new load peaks and lead to higher grid fees as a consequence. Operators of flexible loads must factor in these costs. This creates a competitive disadvantage for flexible loads in the balancing market, as generators do not have to pay any fees for using the grid. Changes are needed here to enable flexible loads to participate in the balancing market on an equal footing.

A further barrier to the participation of flexible loads in the balancing market could arise due to derogations and the exemption from grid fees. As a result of so-called intensive usage of the grid in accordance with article 19, paragraph 1 (2–3) of StromNEV (electricity grid charges ordinance), there are financial incentives to reach a high number of hours of usage. However, participating in the balancing market could mean that the number of hours of usage falls below the required level of 7,000, 7,500 or 8,000 hours a year. Flexible loads would thus in practice be prevented from taking part in the balancing market.

The Transdisciplinary Panel on Energy Change proposes that the grid fee rules should be revised to ensure that flexible loads are not subject to higher grid fees for taking part in the balancing market. Furthermore, the way in which the hours of usage are calculated should be revised to ensure that participation in the balancing market does not impede the process of applying for reduced grid fees.

5. Summary and outlook

In the present study, the Transdisciplinary Panel on Energy Change has made proposals for financing of renewable energies and the enabling demand response. The proposals outlined here are based on the following fundamental considerations:

First of all, the Transdisciplinary Panel on Energy Change takes the view that technologies with variable power output should be treated differently to technologies that can control their power output. Photovoltaic and wind power plants have very high capital costs, no fuel costs/marginal costs, and their output cannot be regulated unless storage technologies become available. Support mechanisms for these technologies should therefore be designed in such a way that risk premiums for financing the plants are kept to a minimum. Transferring price risks (i.e. price fluctuations on the spot market) to photovoltaic and wind power plants is therefore not productive.

The non-productive transfer of risk to the operators of photovoltaic and wind power also makes it harder to achieve the broad financial participation of the community. So far, almost half of the installed power from renewable energies in Germany has been community financed. Civic participation in the financing of renewable energy does not represent added value in itself, but it is a vehicle for the creation of local added value and the acceptance of the further expansion of renewable energies. In the process, it should be remembered that small, decentralised players (private households, community-owned wind farms, energy associations, etc.) tend to have lower expectations of returns but are also more averse to risk in their investment decisions. High risks in financing plants or in marketing the product might adversely affect such smaller, local players.

The electricity system must become more flexible in view of the rising proportion of photovoltaic and wind power that cannot adjust their output. The flexibility required to cover the residual load must also be achieved through power stations with adjustable outputs or energy storage and by adapting the electricity demand. Demand response should also be used for this purpose, and existing barriers to its participation in the market should be quickly removed.

Furthermore, old renewable energy plants for which payment obligations have already been incurred in line with the EEG should no longer be exclusively financed by a levy but in part by an advance payment fund. Driven by the industrialisation process, the EEG has spawned innovations that – as with other power production technologies – should not be financed via a levy on the price of electricity. This would also make it clear that wind and photovoltaics can already produce electricity at a cost that is comparable with new conventional power plants. The proposals for refinancing old plants using an advance payment fund are examined in separate studies and reports.

According to the present schedule, the EEG amendment is due to be passed by the cabinet on 8 April 2014. The first discussion in the Federal Council is due to be held on 23 May 2014. The Bundestag will debate the draft legislation in May and June.

The plan is for the Bundestag to pass the EEG amendment on 26/27 June and the Bundesrat (Federal Council) on 11 July 2014. This would allow the Act to become law on 1 August 2014.

The draft paper produced by the BMWi (Federal Ministry for Economics and Energy) currently assumes that all generators of renewable energies will be obliged to market their product directly as part of the market premium model. In monitoring the energy transition, attention should be paid to what effect these measures have on the structure of the parties involved and the cost of financing.

Following the reform of the EEG, further important strategic decisions must be taken in terms of energy policy. As well as the electricity sector, in future the focus will be increasingly on greenhouse gas emissions in the areas of heat and transport. At European level, energy and climate policy will also be decided after 2020. In this context, negotiations will also take place on a structural reform of EU emissions trading. The Transdisciplinary Panel on Energy Change at the IASS will look at these questions and draw up proposals in consultation with experts from industry, politics, civil society and science.

Appendix 1: The working group “Market system for renewable energies”

Work by the Transdisciplinary Panel on Energy Change

Scientific contributions to the subject of energy change by the Transdisciplinary Panel on Energy Change at the IASS are made independently and on a transdisciplinary basis. The subjects are drawn up by an interdisciplinary team – including experts from industry, politics, civil society and science. The discussions that took place in the working group “Market system for renewable energies – the path to reforming the Renewable Energy Act” were indispensable in preparing the present study. A list of the active members of the working group can be found below. The contents of the present study do not represent a consensus, however, but only reflect the opinions of the Panel on Energy Change at the IASS.

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