Potsdam-Institut für Klimafolgenforschung

A risk perspective on market integration and the reform of support of renewables in Germany

Discussion Paper, February 2015

Michael Pahle
Henriette Schweizerhof (Allianz Climate Solutions GmbH)

A risk perspective on market integration and the reform of support of renewables in Germany[1]

M. Pahle[a*], H. Schweizerhof[b]

*Corresponding author: michael.pahle@pik-potsdam.de
[a]Potsdam Institute for Climate Impact Research (PIK), PO Box 60 12 03, 14412 Potsdam
[b]Allianz Climate Solutions GmbH, An den Treptowers 1, 12435 Berlin

Abstract

After more than a decade of supporting power from renewable energy (RE) through guaranteed feed-in tariffs, the German Government has initiated reforms to integrate RE into the market. To eventually achieve market integration requires that RE investors carry power market risks, in particular the power price risk. At the same time however, under the current financial structure higher risks are likely to have a negative impact on the bankability of new RE projects, which by extension may endanger further deployment and the achievement of renewable targets with it. Against this background we take a risk perspective to assess the past and upcoming EEG reforms, with the aim of developing a proposal to gradually shift risk towards RE investors without endangering project finance. To that end we first discuss the case for more market risk and classify the specific respective risks for RE, analyze how they have been allocated so far, and find that past policy reforms have initiated only a marginal transfer of revenue risks to renewables. On that basis we argue that more ambitious steps in this direction need to be taken, for which regulatory complexity and reform outcome uncertainty suggest a continuous and transparent transition rather than a grand all-at-once intervention. We outline and discuss two elements that could be at the center of it: First, a support framework that creates incentives for RE projects to increasingly take risks, for which we propose a cascading risk auction mechanism that prioritizes “more risky” projects. Second, design options for (a) “more risky” support contracts and (b) risk transfer in power purchase contracts, which if standardized could help to develop and establish suitable risk mitigation and management approaches on the side of financers. While this paper does not deliver a fully spelled-out action plan for these elements, it provides a basic sketch and identifies the main research gaps that should be filled for implementing it. Giving the long lead times of reforms and the need to think ahead that arises from it, we are sure that this proposal can make an important contribution to the next EEG reform in Germany expected for 2016/2017.

[1] The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily reflect the views of Allianz Climate Solutions or the Potsdam Institute for Climate Impact Research.

1. Introduction

In its 2014 amendment of the Renewable Energy Sources Act (EEG) the German government has set out a reform for renewable support that builds on two key elements. First, a compulsory direct marketing of renewable power to be gradually introduced from 2014 on and second, an auctioning mechanism to determine the level of support from 2017 on. A key motivation for this reform is to reduce the costs of renewable support and to achieve integration of renewable energies (RE) into the electricity market, which first of all requires the exposure of RE to market risks that so far have been socialized under the EEG.

Letting RE generators bear the responsibility for market risks and by extension their investment decisions is a critical and controversial issue though – not only for renewable support, but also more generally for all policy formation in privatized energy systems (Moore 2013). In fact, risk and its allocation between different actors is at the center of the current debate on how to reform the EEG[2], as for example underlined in the overview of reform proposals by Pahle et al. (2014). The primary reason is that shifting risk to RE generators constitutes a main deviation from the feed-in tariff model in place since the early 1990s, which many observers view as the main success factor for the large-scale deployment of renewables achieved since the implementation of the EEG in 2000. The original motivation to exempt RE generators from risk was to attract a broad range of investors, in particular smaller firms and private investors, to open up additional sources of finance and gain political support for RE (see Jacobsson & Lauber 2006). In support of this, comparative studies like for example by Mitchel et al. (2006) looking at Germany and England/Wales argued that the feed-in tariff has indeed been more effective than the RO because of the lower risk. But with ever higher shares and rising costs political priorities have changed by now towards a more important role for efficiency besides effectiveness. In its coalition agreement the Government stresses that the feed-in tariff was intended as an instrument to introduce renewable into the market, but in order to contain costs they need to be integrated into the market from now on. The prevailing political spirit for doing so can probably be best described in Ball's (2012) call for government to redesign their support policies: "As renewable power comes of age, it needs some tough love". Importantly, in face of the very ambitious long-term target of 80% RE in power production in 2050, German policy makers are eager to retain at least as much "love" as needed to guarantee finance for deployment.

Against this background, this paper intents to outline an approach how to put "tough love" into action by taking a risk perspective on renewable support in Germany. It does so in the following steps: Section 2 discusses the general economic consideration regarding risks, introduces the relevant revenue risks for project financed renewable energy projects and describes how they are in general shared and transferred through agreements and contracts. Section 3 analyses how past, current and prospective future support schemes allocate these risks from the perspective of the project and takes stock of the risk transfer achieved so far. Based on this, Section 4 draws conclusions regarding design options for the upcoming reforms of RE support, with a view of achieving a cost- and policy-effective risk allocation. Section 5 concludes by including implications in view of uncertainties of the broader market design for electricity in Germany.

[2] It is also a relevant issue for renewable support in other countries like for example in the UK; see Newberry on balancing risk (2012).

2. Risk, risk transfer and relevant risk definitions

The notion of "risk" in economics generally describes the uncertainty of a (positive or negative) change of the value of a certain object (cf. Cottin & Döhler 2013) whereas these changes are characterized by a probability distribution. The value of this uncertainty may be directly or indirectly expressed in quantitative (e.g. monetary) terms. However, some uncertainties as for instance unforeseen regulatory changes are hard to express in monetary or other quantitative terms, because it is hard to fully specify the different (uncertain) events and quantify them in a probability distribution, see Knight (1921). For this reason usually a distinction between risk and uncertainty is made, and it is often said that only risks can be managed. This is usually done with a mix of risk reduction and risk mitigation measures, whereby mitigation also comprises the transfer of risk to other actors, which eventually leads to a reallocation of risks.

Regarding the support of renewables and investment in these technologies, the main concern from a societal point of view is to which extent – if at all – risks should be transferred from RE investors to society through the support scheme design. Important in that regard is that removing market risk from some actors may simply shift it to others and thus not reduce the risk to society as a whole; see for example Schmalensee's (2012) discussion of "RPS vs. FIT" on this issue. From an economic point of view the following general consideration applies: Risk should be borne by the actors that (a) are most willing to bear them and, related to it, (b) can best mitigate them. Such an allocation of risk is efficient, i.e. leads to the lowest overall costs of risk. However, the underlying assumption is that "risk markets" like the financial market work perfectly and risk can be traded away without restrictions by paying a premium (see Kast & Lapied 2006). If this is not the case though, access to finance for renewable projects can be substantially limited because typical lenders like banks refrain from providing debt. Importantly, this restriction may even hold in the case when debt lenders are willing to pay a large risk premium which is known as "credit rationing" (Stiglitz & Weiss 1981) . If in consequence the overall number of bankable projects were too low, RE policy targets would not be reached. This implies that risk for renewable investments needs to be reduced accordingly by transferring them to society to an adequate degree.

Determining which level is adequate, however, needs also to take account of efficiency concerns related to power production: First, risk incentivizes efficient investment decisions under uncertainty. For instance if investors have to bear the power price risk, they will choose the technology and site that is likely to provide highest returns in the future balanced with prevailing risk. In that way they choose the efficient portfolio of technologies with respect to their risk-return profiles. Second, risk is not only a barrier, but also an opportunity for business (upside risk). If the future is uncertain investors are incentivized to innovate in order to outperform the market in the long-run. One example in this regard is long-term wind/solar forecasts. Market risk exposure incentivizes increased efforts into better resource forecasts. A second example is related to the intermittency of solar and wind energy resources and the difficulty to store electricity that poses a challenge to volume control of power production from these resources. The full off-take of all power produced without a minimum or maximum quantity and the exemption from volume risk is unlikely to trigger innovation in this area. Overall, risk taking is a main driver of market-induced technological innovation, and without it stagnation looms.

In summary, a balance has to be found between the need to transfer risk to society in order to meet RE deployment targets while minimizing societal costs, namely by creating incentives for innovation and efficient investment decisions through the use of price signals. How exactly this balance should look like is hard to assess, but it will likely change over time reflecting the changing market environment – and also motivates the transitional approach we take in this paper. On one side, RE technologies have become increasingly mature and business models have been established, which should have reduced the barriers to access to finance. On the other side, a large degree of risk transfer to society has had relatively low impact on costs as long as the share of RE in the market had still been low. With the now considerably high shares in Germany, the downsides of risk transfer to society increase and consequently market integration through risk exposure becomes ever more important. Or as Klessmann et al. (2008) have put it: "If RE shares are higher and their impact on the system becomes more relevant, it seems justified to burden more responsibility and risks on RE projects in order to give them an incentive for cost- reflective market behavior. A precondition should be that the respective markets are mature and competitive". Clearly, as the RE share by now exceeds 25% and the "second quarter" is reached, such a transition seems imminent.

Finally it is necessary to clarify the risks relevant for market integration, which completes this section. A description and classification of risks relevant to investments in (renewable) electricity markets can be found for example in Gross et al. (2010) or Böttcher (2009). As the focus of this paper is on market integration, we concentrate on the four relevant risks on the revenue side: (electricity) price risk, volume risk, support allocation risk and off-taker's default risk. This choice acknowledges that technical risks and overall market risks on secondary markets (primary market = power market) concerning interest rates, currency exchange or cost inflation are so far not of concern for renewable support.

Turning to the risk definitions, ***electricity price risk*** arises from the uncertainty about the future electricity price level and price volatility and the uncertain level of future cash flows that result from it. Also affecting the revenue side is the ***volume risk*** that arises from the uncertainty of the quantity of electricity that can be sold to the market at a certain time relative to what has been contracted before. More precisely, form the seller's perspective it is the risk that a smaller than intended quantity of power can be sold or that a larger quantity than available is expected to be delivered to the off-taker. From the off-taker's perspective, it describes the risk of smaller or larger quantities delivered than desired. A particular volume risk that arises in the short term is *balancing risk*, i.e. the risk that forecasted (day-ahead) production differs from actual production or actual demand respectively. Another main risk for RE is *resource risk*, which stems from the uncertainty if actual resource availability differs from expected average resource availability over the lifetime of a project. As this risk is exogenous and thus not affected by support contracts or power purchase agreements (PPAs), it will not be included in our analysis[3]. That said, it needs to be acknowledged there is a relationship between electricity price and resource risk, especially when the share of renewables is high: low resource availability in one year in general translates into higher prices driven by renewable resource scarcity, i.e. both risk are negatively correlated and can cancel each other out to a certain extent (see Nagl 2013; Tietjen 2014).

[3] An exception is a premium on capacity, which could also reduce resource risk because it is independent of resource availability. This case will be discussed in more detail in Section 4.

Finally, contractual risks at the revenue side are to be considered. Usually power is sold to the market through intermediaries that off-take and trade electricity. This requires a contractual power purchase agreement (PPA) between the two parties and gives rise to a risk that arises from the uncertainty of the contract not being fulfilled according to its off-taking provisions or from the contact being terminated unexpectedly. In the case of termination produced power may not be sold to the market because the so called "route-to-market" is blocked. This can most importantly be the case when the off-taker defaults and hence the central risk in the off-taking contract can be identified as the ***off-taker's default risk*** or *counterparty risk*. Furthermore there is an additional ***support allocation risk*** (see NERA 2013) that arises from the uncertainty if support can be secured, which itself is related to the uncertainties about other applicants and their cost structures. Apparently this is only relevant if available support contracts are limited and up-front development costs occur that are sunk.

Table 1 provides an overview of relevant revenue risks in the context of this paper:

Risk	Relevant uncertainty	Risk description
Electricity price risk	Future development of electricity market prices and market price volatility	Risk of lower income due to unexpected negative price developments (downside risk)
Volume risk	Generation relative to long-term PPA contract; Generation relative to short-term market bid (balancing risk); Availability of network access (grid access risk)	Risk of actual generation deviating from contracted generation
Support allocation risk	Number of other applicants and their costs structures	Risk of not receiving a support contract for an at least partially developed project
Off-taker's default risk	Solvency/persistence of contractor	Risk of unexpected termination of power purchase contract

Table 1: Overview of relevant market risks

3. Risk allocation in past, current & future EEG regimes

This section discusses how the risks introduced in the previous section are allocated in past, the current and possible future support schemes (see Table 2). For this it is helpful to label regimes enacted in amendments to the EEG in software-like versions. This is now common in official government documents (BMWi 2014) and reform proposals like Agora Energiewende (2014) that refer to the 2014 reform as EEG 2.0 and the pending 2016/2017 reform as EEG 3.0. In addition to historic versions and current plans for the EEG we include a hypothetical prospective EEG 4.0 which differs substantially from previous versions by fully transferring price risk to RE projects through the replacement of the sliding market premium by a fixed premium model. The main motivation for doing so is that with this case the transfer of price risks and the respective implications can be analyzed. Thus EEG 4.0 represents an implicit benchmark for a fundamental reform along which the progress in risk transfer of current reforms so far can be measured.

EEG version	Enacted	Main features / changes
1.0	2000	• Feed-in tariff with priority feed-in and dispatch to guarantee full up-take of produced electricity ("Einspeisevorrang")
1.1	2012	• Introduction optional direct marketing with sliding premium plus additional management premium • Monthly option to return to feed-in tariff
2.0	2014	• Compulsory direct marketing based on sliding premium, , management premium abolished • Backstop marketing introduced ("Ausfallvermarktung")
3.0	2017 (planned)	• Compulsory direct marketing with level of sliding premium determined by auctioning
4.0	-	• Hypothetical benchmark case (transfer of price risk to RE projects): Compulsory direct marketing with levels of a fixed premium determined by auctioning

Table 2: Overview of EEG versions (based on EEG history)

In the following we take a project financing perspective, because most large-scale EEG driven investments in Germany have been implemented based on non-recourse or limited-recourse project financing. In accordance with the finance literature we call the project financed legal entity (e.g. a special purpose vehicle – SPV) the "RE project" in the following. The project normally is legally connected to various other actors through contracts (e.g. EPC contract, O&M contract, credit agreement, insurance contracts). Hence risk allocation at the RE project level is to be understood as risk allocation in and through all contracts and agreements between the RE project (as a legal entity) and all other parties legally related to the project.

There are two contracts central to the analysis of risk allocation: (1) the physical off-taking contract with a price mechanism for the produced (and delivered) power which is commonly known as the **power purchase agreement (PPA)** and (2) the financial **support agreement** that provides an add-on payment of a certain amount (fixed or variable) usually per kilowatt-hour of sold power and is thus in general contingent on the off-taking contract.[4] The particular contracts and contractors differ depending on the respective regulatory system. Under the feed-in tariff (EEG 1.0), the grid

[4] The support contract may also remunerate capacity (kW) instead of electricity (kWh). As the overall split is not affected by this choice, we assume the support contract to be a kWh-based support.

connection agreement covers both contracts, physical off-taking together with the support payments (feed-in tariff), and is backed by the legally based power off-taking obligation for the transmission system operator (TSO). In schemes with direct marketing the PPA is for instance given by the direct marketing agreement while the support contract is provided by the TSO which provides the market premium payment.

We furthermore complement our analysis with graphical illustrations, which show the project and its market side contractors (TSO/society, direct marketer/aggregator) in grey boxes. Risks are depicted as blue bars and are included in the respective party's grey box. Contracts are illustrated by green arrows, with a blue flash indicating physical power delivery. A risk that is transferred from the project to another contractor is shown as a hatched box, while a project's retained risk share is a solid box. For simplification, it is assumed that transferring a risk (or a part of it) does not affect its size, i.e. overall risk is "conserved" and just differently allocated. So on the risk taker's side the shading is simply inverted. It has to be kept in mind, however, that through risk mitigation instruments (e.g. pooling risks from different projects in a portfolio) risk may actually be reduced after being transferred. Moreover, the width of each risk bar is indicatively proportional to its respective financial impact on the investment, e.g. price risk for renewables can be considered having the highest financial impact. The sum of all blue boxes equals total market risk. As a further simplification, only direct risk transfer is taken into consideration, meaning that only the risk allocation based on the off-taking, support and grid connection agreements are taken into account. Secondary risk transfer instruments as price or volume hedging at the RE project level are left out in our analysis.

3.1 EEG 1.0: Feed-in tariff

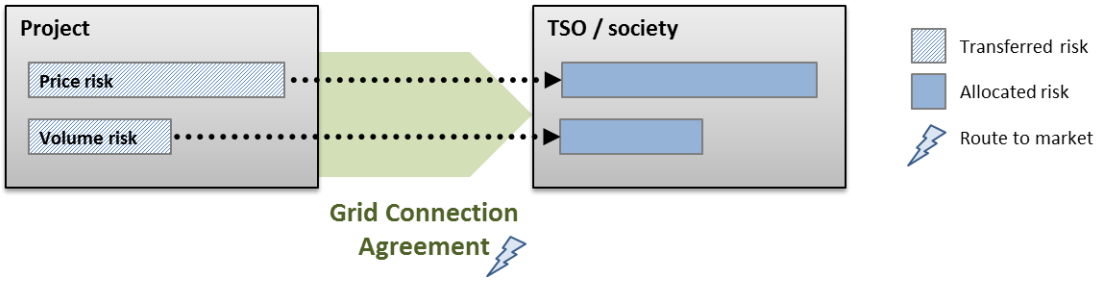

Figure 1: EEG 1.0

The contractual basis of the feed-in tariff is the grid connection agreement with the TSO acting as the counterparty. The underlying contract is basically a PPA that ensures that all produced power is purchased by the off-taker (i.e. the TSO) at the fixed feed-in tariff level. The priority feed-in ("Einspeisevorrang") guarantees that power is purchased at a fixed price per kilowatt-hour independently of current market prices and grid capacities over the contract term (20/30 years plus year of commissioning). In case the TSO needs to curtail production for grid security reasons, the project receives compensation for foregone production according to EEG2014 §11 and §12.

Under this regime there is no price and volume risk for the project at all, because the TSO pays a fixed price per kilowatt-hour delivered and is responsible for balancing (see also Mitchell et al. 2006). As the government backs the off-taking by law (EEG), there is only a negligible default risk of

the respective TSOs. Finally, there is no support allocation risk for projects as there is in principle no limitation for receiving a support contract (technical requirements and regulatory permits aside) except for a marginal one-time risk through the 52 Gigawatt cap for PV support which provides an upper limit of the general access to EEG support for photovoltaic projects[5].

3.2 EEG 1.1: Optional direct marketing with sliding market premium

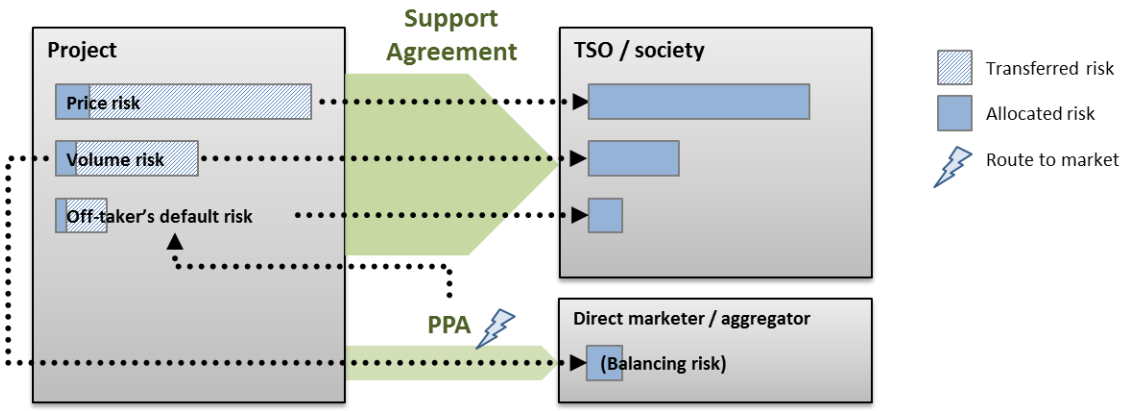

Figure 2: EEG 1.1

The sliding premium support payment is defined relative to the average technology-specific monthly market value (price) at the electricity spot market (EEX/EPEX). The difference between the respective average market value and the technology specific feed-in tariff level are paid to the RE project by the TSO as the "market premium" per kilowatt-hour, complemented by a fixed management premium. Revenues from the power market provide a second source of revenues to the RE project gained either by selling the power directly to the market (less common) or by contracting a direct marketer ("Direktvermarkter") that is sometimes also called aggregator. Typically, direct marketing agreements in this regulatory framework have pricing and volume provisions very similar to a feed-in tariff payment as they normally ensure the off-taking of all electricity produced at a fixed price per kilowatt-hour, with a specific fixed split of the additional management premium between RE project and the direct marketer. There are, however, direct marketing contracts that leave a certain share of the price risk with the RE project through profit/loss sharing of parts of the difference between average technology specific monthly market value and the actual yields realized at the spot market. The direct marketer takes care of balancing, the costs of which are covered by the management premium. Direct marketing contracts normally do not cover the full time period of the EEG support, but often have shorter terms and by extension lower price certainty. They can also be terminated, either in mutual agreement or in case of a direct marketer's default. If the direct marketing contract terminates and no replacement off-taker can be found directly, there is the fallback option to return to the guaranteed feed-in-tariff in the following month.

Under this regime marginal price risk of deviating – both upside and downside – from the monthly average market value has been transferred to the RE project. Based on the common direct marketing agreement this risk is usually transferred from the project to the direct marketer (except

[5] As described in §20 of EEG 2012 and in §31 of EEG 2014.

in contracts with profit/loss sharing provisions) who can best control price risk using e.g. the portfolio effect. Volume risk remains negligible for the RE project as all produced power can be delivered and no quantity requirements exist for the RE project. Default risk from the off-taker agreement arises compared to the 1.0 case but can also be regarded as limited due to very small actual default evidence and default concerning the revenues of one month at maximum and the fallback option to the guaranteed feed-in tariff being rather favorable. As to support allocation risk there are no changes compared to EEG 1.0.

3.3 EEG 2.0: Compulsory direct marketing with sliding market premium

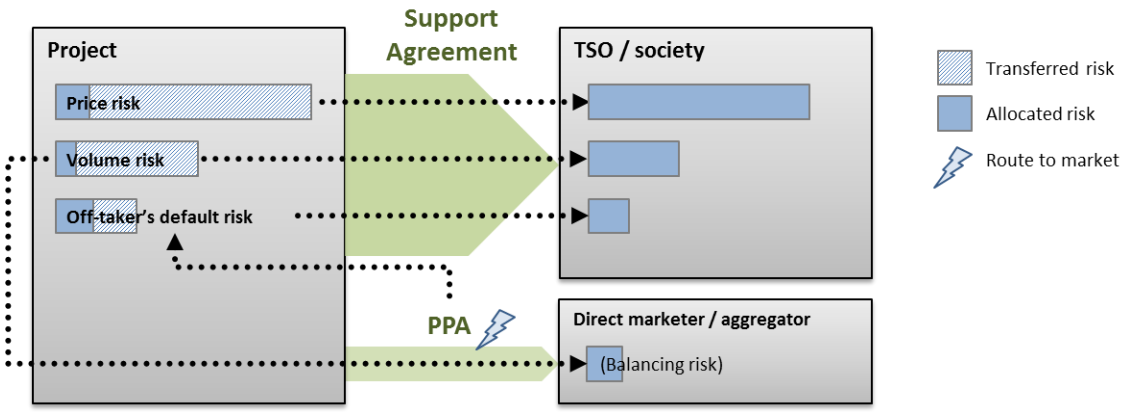

Figure 3: EEG 2.0

Compulsory direct marketing in a sliding market premium system alters the fallback option of switching back on a monthly basis to the classical FIT payment in case of a default or otherwise unexpected termination of the off-taking contract with the direct marketer. Under the 2.0 case the revised fallback option described in §38 ("Ausfallvermarktung") states that 80% of the feed-in tariff can be secured as a fixed payment (analogues to the classical EEG feed-in tariff system). Although this level of feed-in tariff in most cases endangers the profitability requirements for financing RE projects in particular from equity investors' perspective, it limits the financial impact of a direct marketer's default for a RE project in its operational phase during the period until a new off-taking agreement is available.

Under this regime, default risk increases due to the altered fallback options. Price and volume risk are similar to the optional direct marketing scheme of EEG 1.1 assuming that direct marketing contracts continue to provide fixed price provisions per kWh to RE projects. There may increasingly be profit/loss sharing provisions transferring parts of the marginal price risk from the direct marketer to the project, in particular due to the abolishment of the management premium. Here again, no support allocation risk arises.

3.4 EEG 3.0: Compulsory direct marketing & auctioned sliding premium

The main novelty in the EEG 3.0 is that support agreements are not awarded on a first-come-first-serve basis limited only by the deployment collar in case of solar power ("Atmender Deckel"), but

through a reverse auction. Otherwise it will likely be identical to the EEG 2.0[6], which implies that PPAs and support agreements will remain the same[7] and by extension also price risk, volume risk and off-taker's default risk. The only change is the additional support allocation risk for the project, implying additional bidding costs including costs for securing certain financing conditions. The degree to which contract awards will be competitive could vary and thus the size of contract award risk remains yet to be determined.

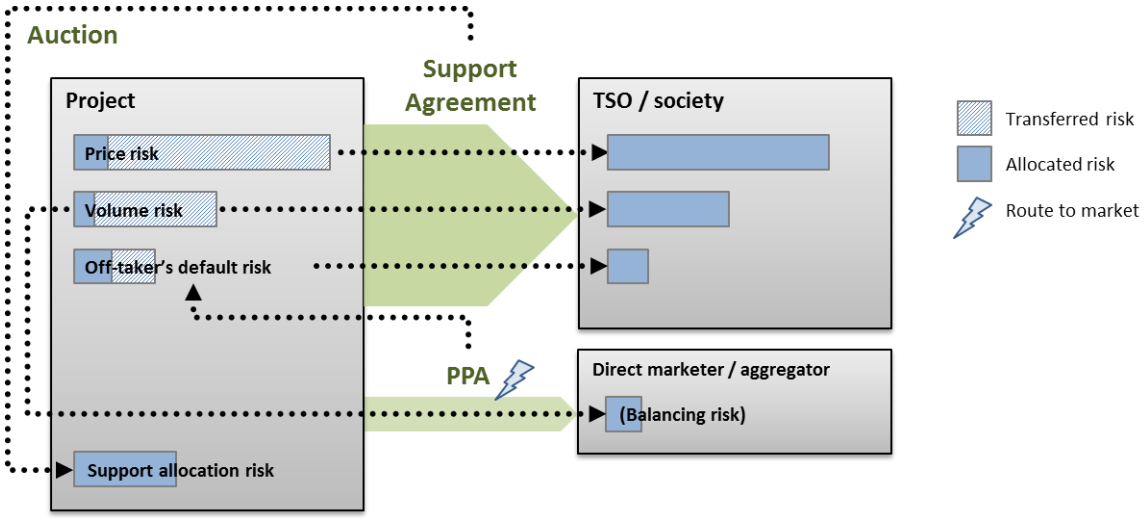

Figure 4: EEG 3.0

3.5 EEG 4.0: Hypothetical "full risk" case with compulsory direct marketing and an auctioned fixed market premium

The main difference of this hypothetical EEG 4.0 to previous versions is a change from a sliding to a fixed market premium, while maintaining the volume provisions of previous cases. In case of a fixed premium, the principal marketing contract arrangements are identical, i.e. power is sold to a direct marketer via a PPA with the fixed premium being paid on top by the TSO through a support agreement. What is different though is that the premium does not compensate the difference between a feed-in tariff level and the monthly average market value at the power market anymore, but is fixed regardless of the market price.

Accordingly the full price risk of fluctuating spot market prices has to be taken by the RE project. The PPA between the project and the direct marketer consequently need to make provisions how to allocate this risk. While a full price risk transfer to the direct marketer (at a higher fee) still is an option – albeit probably not a commonly chosen one – further risk sharing provisions will need to be taken in such a regime. This includes provisions on both price and volume flexibility (e.g. flexible price provisions, fixing quantity or quality in terms of delivery time) of power off-taken by the direct marketer. Accordingly, quantity requirements resulting from price risk provisions could thus

[6] Based on the initial proposal of the German government for the auction mechanism of pilot PV projects from 2015 on, a static auction is intended to be implemented for a certain amount of capacity and with required support level (cent per kilowatt-hours) as the only criterion. Awarded projects will receive the sliding market premiums based on their price bids (used as reference values to calculate the respective market premium), and the awarded project will have no volume restrictions on the quantity of electricity delivered.

[7] Examples from other countries provide, however, various ideas how risk allocation can be steered differently in auction based systems. These aspects will be taken up in the following chapter.

introduce volume risk for RE projects. Volume risk is also affected by the type of market premium: in case of a premium on capacity rather than on production, volume risk would be transferred from the project to the TSO and in this case probably again be taken by society.

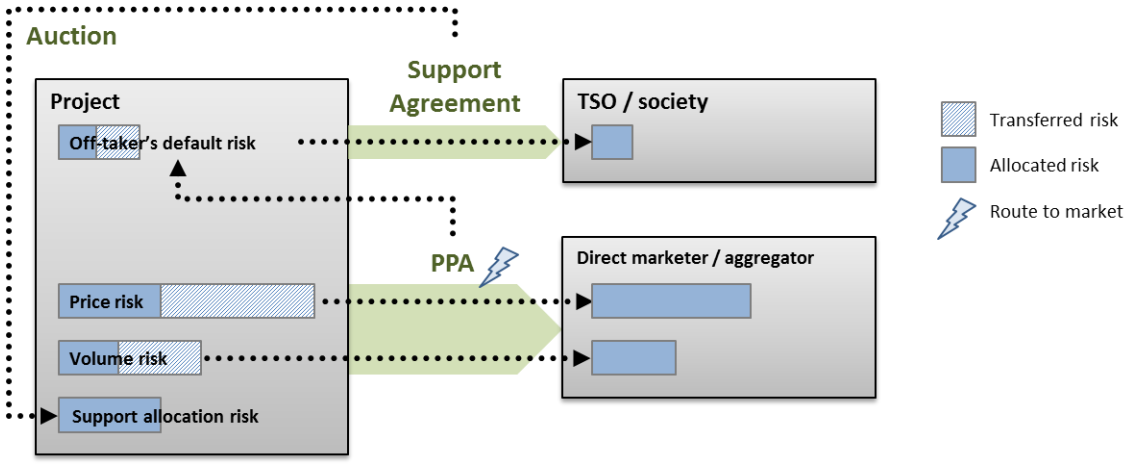

Figure 5: EEG 4.0

Depending on the specific provisions, the magnitude of price and volume risk can be considerable under such a regime. A project may be unable to allocate the price and volume risks in a way that keeps the project bankable. They key factor here is to which extent there is a liquid market for PPAs that allocate these risks efficiently between project and off-takers and how PPAs must be designed (also in view of possible additional risk mitigation instruments) in order to meet the criteria lenders and equity investors require for their credit and investment assessment respectively . In case risk allocation through PPAs in this market environment would leave many projects non-bankable, partial risk transfer could become again part of the support contract (i.e. fallback prices etc.) which would imply transferring parts of price and volume risk back to society to the extent necessary to ensure that the desired deployment of RE project can take place. This will be elaborated in the following section.

3.6 Summary

The analysis of the version of the EEG so far show that historic reforms have gradually transferred risk to the project level, namely marginal price risk as well as a low off-taker's default risk (see Figure 6). With EEG 3.0, support allocation risk will be introduced, but is likely also only a small step of risk transfer in particular as auctioning quantities are assumed to remain in the ranges of current deployment target ranges. Consequently, EEG reforms so far have been incremental in transferring risk to the RE project level, basically only shifting marginal parts of price and volume risk while also providing for a range of fall-back options regarding off-taker's default risk. Hence assuming that market integration will require that RE projects bear the full price, volume and off-taking risk, it becomes evident that there is a considerable amount of risk still to be transferred to RE project level.

At the same time previous German reforms as well as examples from other countries have shown that the cautious steps taken have likely been critical to avoid a disruptive investment environment. The key challenge can thus be seen in how to further design a continued risk transfer to the project level while keeping RE projects bankable. The central aspect will probably be the transfer of price

risk, where risk transfer is still marginal in the EEG 3.0 and there are yet no proposals except for Agora Energiewende (2014) how to gradually transfer this risk to projects – rather than reforming from marginal to full price risk in a single step as described with the hypothetical case EEG 4.0, which could render hitherto viable RE projects non-bankable. In the next sections we take a closer look on how such a transition could be implemented.

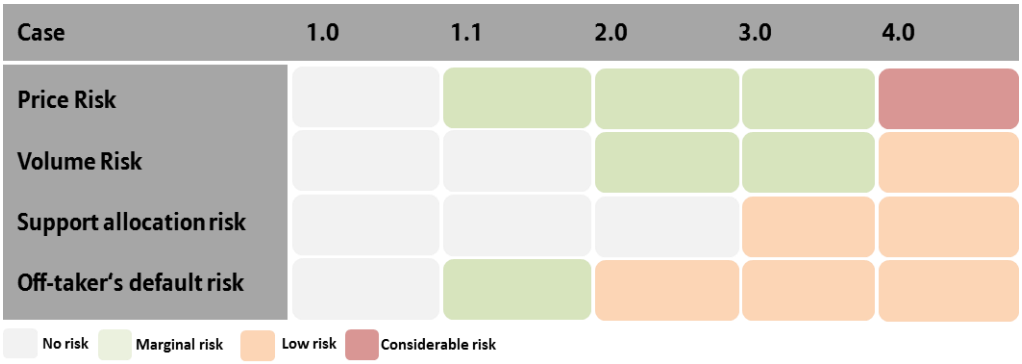

Figure 6: Overview on the risks at the RE project level in the various EEG cases

4. Enabling more risk in RES support

The previous section has shown that while some risk has already been transferred to RE projects in previous reforms, the amount of risk yet to be transferred to achieve market integration is considerable. In consequence ambitious steps need to be taken in this direction and the crucial question is how this can be done in a prudent way. In face of the regulatory complexity and outcome uncertainty that usually come along with ambitious reforms, a continuous transition that gradually shifts risk seems more promising than a grand all-at-once intervention. In particular it may allow for learning how to better deal with risk at the project level without endangering project finance.

We suggest that two elements should be at the center of such a transition: First, a support framework that creates incentives for RE projects to increasingly take risks, for which we propose a cascading risk auction mechanism that prioritizes "more risky" projects. The main idea behind it is that different types of investors differ in their willingness and ability to handle risks, and this potential should be exploited by letting them choose what best suits them. Hence risk is transferred to different degrees for different investors. This however requires the design of a "more risky" support contract and probably also standardized provisions for risk transfer in PPAs which are the second element of our approach. In particular standardized PPAs could help to develop and establish suitable risk mitigation and management approaches on the side of financers. In the remainder of this section we outline and discuss both elements and identify main areas for further research in order to support implementation.

4.1 Auctioning framework: Split & Cascading Risk Auction

As mentioned the first main idea is to differentiate risk transfer between different types of investors. A relatively simple approach for doings so is to steer by capacity in a "**split risk auction**" and tender specific shares to be determined by the regulator in for example three risk categories as shown in Table 3. Category II is based on the EEG 2.0 framework, i.e. a sliding market premium with compulsory direct marketing. In contrast category I would impose higher risks on projects by means of "more risky" support contracts however designed (see below). Both categories could be tendered by means of competitive auctions with the required support level ("price") as the single relevant criterion. In contrast, category III is conceived to be less risky with regard to the auction type. One way of doing this is to make use of non-competitive bids like for instance used in the auction mechanism of treasury bonds. That is, some projects would not be selected in a competitive process but are afterwards offered support for the lowest/average/highest bid and thus would not be exposed to support allocation risk. However, as bidding projects in this category are likely to exceed available capacity open for tender, a first-come-first-serve rule would need to be applied. Alternatively, a so called scoring auction – see for example Che (1993) – based on single or multiple non-economic criteria could be used to determine who wins and who loses ("competitive in score").

Category	I	II	III
PPA / Support agreement	"More risky"	Sliding premium (EEG 2.0)	Sliding premium (EEG 2.0)
Auction type	Competitive in price	Competitive in price	Non-Competitive first-come-first-served / Competitive in score
Overall risk transfer to project	High	Medium	Low

Potential type of investor	utilities, large municipalities, large investors	energy cooperatives, small municipalities, utilities, mediums-sized investors	Small private investors, energy cooperatives

Table 3: Risk categories in a split risk auction

This approach has several advantages. First, in accordance with the relatively cautious reforms so far it would allow learning about higher risk taking in a smaller pilot group for category I, with experimental shares in the order of magnitude of say 10%. Second, it would also allow continuing with the exemption of certain groups from risk taking in category III. But it also has some disadvantages. First and foremost, it is very unlikely that fixed shares determined administratively exactly correspond to the shares of RE projects willing and able to take more or less risks in the market. More specifically, there may be either a higher share (e.g. 20%), in which case category I (10%) would be too small and existing risk-taking potential in the market remains unexploited. Or the share may actually be smaller (e.g. 5%), in which case there would be insufficient bids so that demand exceeds supply, which creates considerable potential for market power. Such a lack of competition would clearly undermine the use of auctioning altogether. Consequently the risk allocation to be achieved with fixed category shares is relatively easy to implement, but unlikely to be efficient.

An alternative approach that addresses these disadvantages is to let the market decide about the allocation of risk in the limits of the above categories. The economically straight-forward way for doing this would be to have two criteria, i.e. an explicit required risk premium besides the required support level, and two support contracts, less and more risky (see above), in a single auction. However, in order to get a strict ranking of all bids to determine winners, this design requires quantifying the risk difference between the products/contracts, i.e. to set a benchmark. This of course is a considerable challenge for a regulator and hardly seems feasible in practice.

Alternatively, one could auction the different categories in sequence (instead of in parallel) in what we term "**cascading risk auction**"; see Figure 7 below. The principle is the following: First, category I support is auctioned whereby a limit on contracted capacity other than the annual target arises only implicitly by setting a non-disclosed reserve price, i.e. the price which a bid must not exceed. The auction mechanism could be similar to the one used for Japanese public construction projects (see Kawai & Nakabayashi 2014): In the first round bidders make private bids and if none of them is below the secret reserve price, the regulator reveals the lowest bid (but not the identity of the bidder and the reserve price) to all the bidders and solicits a second and possibly also third round of bids. After determining the winners only a certain share of the annual capacity target remains, which is then "cascaded" to category II, i.e. the maximum capacity auctioned in category II is the annual target minus the capacity allotted in the previous category I auction. The same happens for category II, i.e. it passes remaining capacity on to the category III auction. This approach can be said to implement a highest-risks-first-served principle.

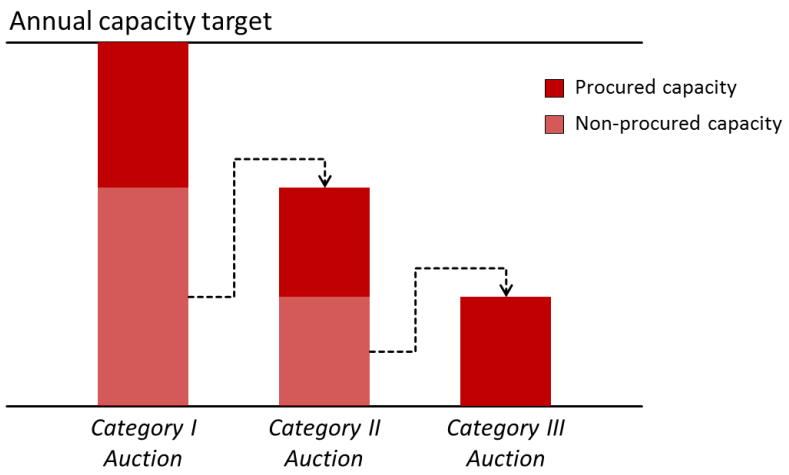

Figure 7: Cascading risk auction

As mentioned the main advantage of this approach is that its risk allocation is very likely to be more efficient because it leaves it up to market participants to decide about risk taking. Moreover, there is also a competitive element that incentivizes risk taking: tendered capacity is reduced over the categories and risk-reluctant investors may end up with no remaining capacity to be auctioned in category III because it has been fully allotted in the previous auctions. This is very likely to induce risk management capacity building over time and could thus bring the scheme dynamically closer to an EEG 4.0. If on the other side market participants are unable to build up this capacity or their risk premiums are too high, the "cascading risk auction" would automatically fall back into the EEG 3.0 scheme because all capacity would presumably be auctioned in category II. In this sense it is also a kind of fail-safe approach, but nevertheless has a somewhat higher implementation risk compared to the EEG 3.0 because of the ex-ante uncertainty about which risk category will be accessible.

That said there are also challenges that come along with this approach. The first one is to set the hidden reserve price required for the category I and II auctions appropriately. If this price is too low and underestimates the actual risk premium, then bids will on average be too high and capacity contracted in this category too low. Conversely, if the regulator sets this price too high, then there are "risk rents" to be made and capacity contracted in this category is too high. In fact, finding an appropriate reserve price would certainly require a careful risk analysis and sophisticated methods for benchmarking. A main issue here is to identify – and thus also learn about – the risk premium required to make them bankable, and related to it how hurdle rates change for higher risks. For this one could possibly also draw on methodologies that were applied in the context of the UK reform, for example by NERA (2013).

In addition, this approach would also require a well-designed auction capable of preventing collusion. Very common for example are bidding rings in which winners are predetermined and all other bidders only submit non-serious high-bids (see Kawai & Nakabayashi 2014). This in particular applies for auctions in which there is only one winner (i.e. construction projects), but may also be possible for the situation looked at here. Moreover, it may in principle also be possible for bidders to behave strategically "between" category I and II. All of these issues need to be addressed in a sound economic analysis like for example done by r2b & BTU Cottus (2014) for the currently planned PV pilot.

4.2 Support contract and PPA design

In order to put differentiated risk transfer into practice, transfer of price and volume risk requires a new support contract design with appropriate provisions. But it is clear that these provisions would consequently change the contractual part of the marketing (PPA) where the retained price and volume risks need to be allocated between the RE project and the private physical off-taker in a negotiation process. Accordingly it is likely that a much broader spectrum of PPAs with different risk allocations between RE project and off-taker will emerge in response. Importantly, the possible design options for risk transfer provisions are basically the same for both support contracts and PPAs.

Regarding "more risky" support contracts, price and volume risk transfer could be within the range set by the two extremes described in Section 3: a sliding premium scheme (marginal price and volume risk at project level) and a fixed premium scheme on generation (full price and volume risk at project level). Between these two "extremes" there is a variety of contracts that can transfer these two risks to different degrees. How to do this can be first of all learned from the analogously designed PPAs, for which a number of worldwide examples exist (see below). In addition to support contract design providing the framework for overall risk transfer, back-stopping PPAs could be linked to support contracts in order to (a) offer a standard allocation of price and volume risk between project and off-taker and (b) provide a back-stopping off-taker (e.g. a utility) based on these terms so as to ensure "liquidity" in the category I PPA market. This approach has for instance been discussed in the context of the introduction of Contracts for Differences in the UK (Baringa LLP 2013).

Beyond back-stopping PPAs, risk allocation also needs to be defined in the respective PPA – also in consideration of additional risk mitigation instruments. This allows price and volume risk allocations by defining all modalities of delivering and off-taking of produced power from the RE project. The modalities of a PPA determining risk allocation are given in Table 4. They allow controlling the degree of volume and price risk transfer from the project to the off-taker, in particular through the price mechanism.

PPA Term	The duration of a PPA may vary from long-term contracts of 20 years or more to short-term contracts of just a few years.
Power quantity and quality	The PPA may set a fixed annual quantity of electricity delivered per year (e.g. in MWh) or may take off all electricity produced by the generator. Also, the quality in terms of delivery at specific times (e.g. during peak-demand) may be defined.
Price Mechanism	The purchase price may be paid per kWh or capacity based. Price mechanisms may range from fixed prices per kWh to price bands, variable prices or various price elements.
Liability clauses	Rules and sanctions e.g. in case of not meeting minimum delivery quantities.
Modes of termination	Relevant in case of delayed project completion, permanent non-delivery or permanent non-payment for delivered electricity.
Mode of electricity delivery	Use of public grid or not.
Solvency terms for Off-taker	Especially relevant for long-term PPAs with third parties

Table 4: Overview on PPA design modalities

Regarding the transfer of price risk, a price mechanism that explicitly or implicitly fixes a price per kilowatt-hour is essentially a price-hedging financial forward contract. In the grid connection agreement in the EEG 1.1 for example the sliding market premium implicitly references the (fixed) feed-in tariff rate. In that way price fluctuation at the spot market are always balanced by premium fluctuation in the opposite direction and essentially no price risk occurs (see previous chapter). To include more price risk the feed-in tariff levels could be differentiated between on-peak and off-peak delivery time, which makes reference to differentiated intraday power price levels. This is a more differentiated approach than averaging price volatility over an entire month and induces respective incentives on a daily scale. This approach is for instance already used in standardized PPAs offered in California (*Southern California Edison, 2014*)[8]. Another option is to have a longer-term escalation clause instead of a flat price over the whole term like for example used in Texas (Smith, DeWolf & Wetsel 2011). If this is the case the parties must determine when the price escalator kicks in and which level it takes. The latter may be set at a fixed (percentage) amount or pegged to inflation or price index. Here directly pegging to a power price index means more risk for the project and risk could further be increased by weaker "indexing", for example by imposing certain upper and lower bounds.

At the volume side, yearly minimum and/or maximum amounts of electricity off-take could be introduced with sanctions for over- or underperforming a certain tolerance level. These regulations are for instance included in standardized Californian PPAs or in standardized PPAs in South Africa. Furthermore, more detailed volume based flexibility requirements, e.g. target volumes for shorter time periods or based on on-/off-peak times, could be included. Furthermore, a fixed premium on capacity instead of generation would partially mitigate volume risk because in this case the support revenue stream is independent of the second revenue coming from produced (and sold) power.

Given the many possible design options for category I, the crucial question is which particular options are the most appropriate. First of all it has to be pointed out that there is no simple scale along which the relative risk allocation of any combination of options can be ranked. Moreover, even if such a scale existed it would not help unveiling the scale of risk appropriate for the "more risky" support contracts described above ("category I") so that it could be successfully allocated between the two contractors: increasing risk too little relative to EEG 2.0 would probably not achieve any progress/learning, while increasing risk too much (i.e. fixed market premium) would probably be too ambitious given the current "readiness" for more risk; see Figure 6.

That said in order to inform the design of a suitable "more risky" standardized support contracts for category I and their implications for the risk then to be included and efficiently allocated in the PPA, two things could be done: First, it could be learned from PPAs worldwide which provisions can well be handled in terms of risk management. In particular the cases mentioned above like for instance South Africa and California seem to be very promising. Second, investors and financers could be surveyed regarding how they rank different options in terms of risk and bankability, for example by using conjoint analysis as done by Lüthi & Wüstenhagen (2012). And finally, methods for risk assessment could be developed or further refined, also based on what has been done in other countries like for example by NERA (2013) for the UK. It seems also worthwhile to consider how this

[8] For more US PPAs see https://financere.nrel.gov/finance/content/renewable-energy-contracts-library

can be combined with the design of auctions planned intended to be implemented in 2017. But this is beyond the scope of this paper and subject to further research.

5. Conclusions and consideration of uncertainties

The analysis of the versions of the EEG support so far and the outlook on future versions have revealed that a clear timeline for transferring risks to RE projects in order to fully integrate them into the electricity market is missing. Given that it is most promising to do this in a gradual way, the least one can say is that a continuous transfer would hardly be achieved by shifting to a fixed premium model in a next EEG reform as this would imply the introduction of full price risk at the project level. Instead, price and volume risk transfer could be transferred by a differentiation of support contracts to be awarded, using three categories and possibly also a cascading risk auction. In particular a "more risky" tranche could be used in combination with physical off-taking agreements (PPAs) that allocate risk between projects and off-takers specifically. The main benefit is that it could trigger learning process for the use of risk mitigation instruments, also by drawing on international experience with PPAs and risk instruments.

Determining the appetite for "more risky" tranches and the degree to which RE projects would in general remain bankable in such a setting does, however, not only depend on the risks considered so far, but is also driven by uncertainties from the broader regulatory environment of RE projects. The crucial uncertainty in that regard is the still unresolved question of the future electricity market design, which is likely to have considerable – but yet unknown – influence on the price setting mechanism at the spot (and futures) market. This uncertainty affects RE projects – and of course also conventional investment projects – considerably, as the electricity price determines the fallback marketing option outside the EEG or other longer term PPAs.

What does this imply for gradual risk transfer? In similarity to what has been discussed for and warned of in the context of capacity markets (cf. Wissenschaftlicher Beirat beim BMWi 2013) any market-based long-term market or support scheme requires that investors are able to form stable expectations about prices in these markets. This can only be accomplished through a transparent and credible long-term approach to upcoming electricity market reforms, including electricity market design for energy and potential capacity markets as well as the EU wide reform of the carbon market. These reforms will need to go hand in hand with the gradual risk transfer of price and volume risks to RE projects. In fact, it is pretty much the speed of these reforms that puts the upper limit on the risk transfer that can be achieved. Without such a stable framework market integration of renewables is unlikely to be achieved.

References

Agora Energiewende, 2014. Erneuerbare-Energien- Gesetz 3.0. Konzept einer strukturellen EEG-Reform auf dem Weg zu einem neuen Strommarktdesign (Kurzfassung). Verfügbar unter: http://www.agora-energiewende.de/fileadmin/downloads/publikationen/Impulse/EEG_30/Agora_Energiewende_EEG_3_0_KF_web.pdf.

Ball, J., 2012. Tough Love for Renewable Energy. Foreign Affairs.

Baringa LLP, 2013. The Backstopp PPA Proposal. Report to the UK DECC. Verfügbar unter: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/253179/Backstop_PPA_Proposal__report_by_Baringa_LLP___Report_published_July_2013_.pdf.

BMWi, 2014. Zentrale Vorhaben Energiewende für die 18. Legislaturperiode. 10-Punkte-Energie-Agenda des BMWi. Verfügbar unter: http://www.bmwi.de/BMWi/Redaktion/PDF/0-9/10-punkte-energie-agenda,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf.

Böttcher, J., 2009. Finanzierung von Erneuerbare-Energien-Vorhaben, München: Oldenbourg, R.

Che, Y.-K., 1993. Design Competition Through Multidimensional Auctions. The RAND Journal of Economics, 24(4), S. 668.

Cottin, C. & Döhler, S., 2013. Risikoanalyse Modellierung, Beurteilung und Management von Risiken mit Praxisbeispielen, Wiesbaden: Springer Spektrum.

Gross, R., Blyth, W. & Heptonstall, P., 2010. Risks, revenues and investment in electricity generation: Why policy needs to look beyond costs. Energy Economics, 32(4), S. 796-804.

Jacobsson, S. & Lauber, V., 2006. The politics and policy of energy system transformation—explaining the German diffusion of renewable energy technology. Energy Policy, 34(3), S. 256-276.

Kast, R. & Lapied, A., 2006. Economics and finance of risk and of the future, Chichester, England ; Hoboken, NJ: John Wiley & Sons.

Kawai, K. & Nakabayashi, J., 2014. Detecting Large-Scale Collusion in Procurement Auctions. Verfügbar unter: https://files.nyu.edu/kk2319/public/draft_0411.pdf.

Klessmann, C., Nabe, C. & Burges, K., 2008. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. Energy Policy, 36(10), S. 3646-3661.

Knight, F.H., 1921. Risk, Uncertainty, and Profit, Boston: Hart, Schaffner & Marx; Houghton Mifflin Co.

Lüthi, S. & Wüstenhagen, R., 2012. The price of policy risk — Empirical insights from choice experiments with European photovoltaic project developers. Energy Economics, 34(4), S. 1001-1011.

Mitchell, C., Bauknecht, D. & Connor, P., 2006. Effectiveness through risk reduction: a comparison of the renewable obligation in England and Wales and the feed-in system in Germany. Energy Policy, 34(3), S. 297-305.

Moore, S., 2013. Going, Going, Gone. The role of auctions and competition in renewable electricity support. Policy Exchange. Verfügbar unter: http://www.policyexchange.org.uk/images/publications/going%20going%20gone.pdf.

Nagl, S., 2013. The effect of weather uncertainty on the financial risk of green electricity producers under various renewable policies. EWI. Verfügbar unter: http://www.ewi.uni-koeln.de/fileadmin/user_upload/Publikationen/Working_Paper/EWI_WP_13-15_The_effect_of_weather_uncertainty.pdf.

NERA, 2013. Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime. Verfügbar unter: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267650/NERA_Report_Assessment_of_Change_in_Hurdle_Rates_-_FINAL.pdf.

Newbery, D.M., 2012. Contracting for Wind Generation. Economics of Energy & Environmental Policy, 1(2).

Pahle, M., Tietjen, O., Joas, F., et al., 2014. EE Förderinstrumente & Risiken: Eine ökonomische Aufarbeitung der Debatte zur EEG Reform. PIK Diskussionspapier. Verfügbar unter: https://www.pik-potsdam.de/members/pahle/pahle-et-al-forderung-ee-und-risiken-marz-2014.pdf.

r2b & BTU Cottbus, 2014. Auktionsdesign für Photovoltaikanlagen auf Freiflächen. Gutachten im Auftrag des BDEW. Verfügbar unter: https://www.bdew.de/internet.nsf/id/2A92AD1E977DD9F5C1257D550038E245/$file/160_Bericht%20Auktionsdesign_final.pdf.

Schmalensee, R., 2012. Evaluating Policies to Increase Electricity Generation from Renewable Energy. Review of Environmental Economics and Policy, 6(1), S. 45-64.

Smith, E.E., DeWolf, S.K. & Wetsel, R.E., 2011. Texas wind law, Verfügbar unter: http://www.lexis.com/xlink?source=matben;txwind.

Stiglitz, J.E. & Weiss, A., 1981. Credit Rationing in Markets with Imperfect Information. American Economic Review, 71(3), S. 393-410.

Tietjen, O., 2014. Analyses of Risk Factors in Conventional and Renewable Energy Dominated Electricity Markets. Master Thesis FU Berlin.

Wissenschaftlicher Beirat beim BMWi, 2013. Langfristige Steuerung der Versorgungssicherheit im Stromsektor. Verfügbar unter: http://www.bmwi.de/BMWi/Redaktion/PDF/Publikationen/Studien/wissenschaftlicher-beirat-langfristige-steuerung-der-versorgungssicherheit-im-stromsektor,property=pdf,bereich=bmwi2012,sprache=de,rwb=true.pdf.