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D5.2: Best practice design features for RES-E support schemes and best practice methodologies to determine remuneration levels

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Authors: Anne Held, Mario Ragwitz (Fraunhofer ISI)
Malte Gephart, Corinna Kleßmann, Erika de Visser (Ecofys)

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1 Introduction

In Europe electricity from renewable energy sources (RES-E) has mostly been supported through feed-in systems. In particular feed-in tariffs pose a low risk on RES-E investors, since a guaranteed tariff is typically paid regardless of the demand at any time of production. Thus, the core strength of feed-in systems is to minimise investment risks for RES-E. However, feed-in tariffs are often criticised for not sufficiently encouraging market integration of RES-E. Alternative support instruments that have been applied in Europe are quota schemes, which are characterised by a stronger exposure of RES-E producers to electricity and certificate price risks. Thus, quota obligations are distinguished by a stronger market risk exposure, but typically involve higher investment risks than feed-in systems.

While investor risks and market risk exposure appear to be conflicting principles of RES-E policy design, they are commonly justified by the same argument: the limitation or reduction of RES-E support costs, either through the limitation of risk premiums for investors (and thus required support expenditures) or through exposing them to market competition and selecting least-cost options.

The European Commission has repeatedly called for stronger market exposure to be imposed on RES-E producers, arguing that competitive energy markets would drive investment decisions into energy conversion technologies in a cost-effective manner (e.g. European Commission 2013). However, it seems relevant to distinguish between the markets concerned, i.e., on the one hand, the electricity market and its sub-markets, in which RES-E needs to be integrated, and, on the other hand, a market-based allocation procedure of support payments for attracting RES-E investments e.g. by using auctions (see e.g. Klessmann et al. 2008).

In this report we will use the term "market compatibility" to describe multiple aspects of applying market principles to RES-E support schemes and limiting policy costs:

First, there is the challenge to integrate large shares of variable RES-E generation into electricity systems and markets. Therefore, with increasing RES-E shares, RES-E generators should be exposed to electricity markets and finally be dispatched according to market signals, in order to limit the overall market integration costs.

Second, the reduction of policy costs to support RES-E generation is of utmost importance during the coming years. Strong growth of some renewable technologies, such as Solar PV, has led to strongly increasing policy costs. This effect has been reinforced by the price-reducing effect of RES-E with no fuel costs, the merit order effect, as the difference between the market value and the cost of RES-E is compensated for by the public, policy costs have increased. Increasing the market value of RES-E and allocating RES-E support payments in a competitive procedure may potentially reduce RES-E policy costs.

Third, some support schemes in Europe still grant excessive support for RES-E generation in particular due to the difficulty to follow rapid cost degression of RES-E technologies. Competitive elements in support schemes determining the level of support might improve the cost reflective character of remuneration levels.

Fourth, taking a European perspective, low cost RES-E generation options in some Member States are still not fully exploited today whilst more costly potentials are exploited in other countries. Avoiding such an uneven exploitation of RES-E potentials in Europe can help to reduce policy costs for RES-E. Thus, elements of international cooperation can also help to reduce overall policy costs at EU-level.

Related to these basic and mainly conflicting aspects of market compatibility and investment risk, the trade-off between both dominates the current debate about reforming support schemes for RES-E. Improving market compatibility – typically required for feed-in systems – can either refer to the plant operation or to the investment decision. First, market compatibility regarding plant operation can be improved by incentivizing the reaction of RES-E generators to short term price signals at the spot market. This in turn is related to the aim of increasing the value of RES-E by exposing and integrating RES-E into the portfolio of electricity markets, where possible (e.g. day-ahead, intraday, balancing, futures). Second, increasing market compatibility linked to the investment can be achieved by introducing competitive elements to determine remuneration levels of support schemes (e.g. tenders or quota schemes) instead of using administrative procedures to determine the tariff level. Several countries have recently started to combine feed-in systems with auctioning systems in order to better control policy costs and to achieve more cost-effective support levels. However, experiences with auctions are mixed and have shown important challenges to adequately design these auctions.

Moreover, increasing the level of competition between all RES-E potentials in Europe for the achievement of a common EU RES-E target can improve European market compatibility of RES-E support (which is represented by the extreme solution of fully harmonised support across the EU as compared to differentiated prices at Member State level).

However, all means to improve market compatibility generally increase the risk related to investments in RES-E. Such investment risks materialize on the level of the weighted average costs of capital (WACC) for RES-E technologies. When aiming for a cost-effective support strategy, one may discuss which risks should be allocated to the RES-E investor or generator and which to the public (see Rathmann et al. 2011). It seems crucial to keep the investor risks on a (from the investor's perspective) acceptable level because the impact of higher capital costs for capital-intensive RES-E technologies on total generation costs and therefore on support expenditures is high. In addition, a large part of the RES-E portfolio is close to competitiveness in terms of levelised costs of electricity (LCOE) if low WACCs are applied. Notwithstanding this development, substantial policy costs will still occur for the next decades; reducing them as much as possible seems thus advisable to policy makers.

Finally, the level of the investment risk does not only impact the cost-effectiveness of a policy (support needed to incentivize investment) but also the effectiveness (whether or not investment will be done). Therefore, reducing investment risks will have a strong effect on Europe’s performance in terms of achieving the RES-E targets.

All this suggests aiming for a reasonable trade-off between increasing market compatibility of RES-E and limiting investment risks. As mentioned initially, Member State policies for RES-E applied in the past originate from two extreme alternatives: technology-specific fixed feed-in tariffs (FITs) and technology neutral quota schemes combined with tradable green certificates (TGCs). Each of these extremes puts emphasis on one of the policy goals described above: technology-specific feed-in tariffs focus on minimization of investment risk and avoidance of excessive remuneration for less cost-intensive technologies, whilst technology-neutral quota systems focus on maximization of market compatibility and selecting the technology options with the lowest (short-term) generation costs.

In recent years Member States have reformed support schemes in order to address the major weaknesses of these two policy options. Thus, support scheme design of FITs and quota obligations is converging. For feed-in systems addressing its weakness of a lack of providing market signals for RES-E producers and investors has resulted in a transition from fixed FITs towards feed-in premiums (FIPs), which are paid on top of the price for directly marketed electricity. Moreover, auctions have been introduced for a more competitive determination of remuneration levels. In case of quota systems, minimum price levels and long term quota targets have been implemented to address high exposure of RES-E investors and producers to risks. Moreover, concepts to reduce risks under quota schemes include the transition to more frequent use of long term contracts for TGCs, possibly facilitated by the implementation of an off-taker of TGCs who is refinanced by the government. In addition, some Member States have introduced technology-banding in order to avoid windfall profits and to provide sufficient support for more expensive technologies.

In the context of the two major current challenges of RES-E support explained above, increasing market compatibility and risk reduction, this report discusses best practices in feed-in systems and in quota schemes that successfully address this fundamental trade-off.

In addition, improved support scheme design clearly has a European dimension. Coordination among Member States can improve their policy design, mainly by converging towards established best-practices. For instance, Member States could coordinate strike prices and methodologies to determine these strike prices. This would allow for an improved resource allocation in Europe in a longer term and thereby for reduced policy costs.

Along these lines, this report first discusses in detail design features of feed-in systems, including their market orientation from an operational perspective, the setting of strike prices and the revision and adjustment of strike prices over time. Second, the report discusses quota schemes and how their main drawback can be addressed, namely how banding factors and penalty levels can be adequately defined. Third, it discusses different burden sharing approaches and finally it explores the current status of and ways to coordinate the design of RES-E support schemes throughout Europe.

2 Design features of feed-in systems

The main advantage of feed-in systems has been to minimize investment risks for RES-E. However, there have been repeated calls to better integrate RES-E into the market, so that they can become part of an efficient way of matching demand and supply. This chapter deals with experiences of feed-in systems in particular related to the challenge of increasing market compatibility of the instrument while still limiting investment risks. Thus, we first elaborate on possibilities to increase market compatibility by shifting to premium models in section 2.1. Second, we analyze experiences with defining strike prices in feed-in systems (see section 2.2) and different options to revise and adjust these strike prices over time (section 2.3).

2.1 Types of feed-in systems and their approach towards market integration of renewables

2.1.1 Types of feed-in systems

A feed-in tariff can be paid to RES-E generators as an overall remuneration (the *fixed tariff*) or alternatively as a premium, that is paid on top of the electricity market price (the *premium tariff*). In the case of a FIT design, RES-E producers receive a certain level of remuneration per kWh of electricity generated. In this case, the remuneration is independent from the electricity market price. In contrast, the development of the electricity price has an influence on the RES-E producer's revenues under the premium option. Hence, the FIP represents a modification of the commonly used fixed tariff towards a more market-based support instrument.

In general, three main types of FIPs can be differentiated: In the case of a fixed premium, the premium does not depend on the average electricity price in the power market. Thus, the revenue risk when compared to FITs is increased as the renewable generators bear all price risks from the electricity market. Furthermore, from the perspective of covering the producer's LCOE, over- and under-compensation may occur. A feed-in premium with cap and floor prices reduces revenue risks and surpluses as only a certain income range is allowed for under this model. In case of the sliding premium or contract for difference (CfD), where the premium is a function of the average electricity price and the strike price stays constant, the revenue risk does not increase significantly.

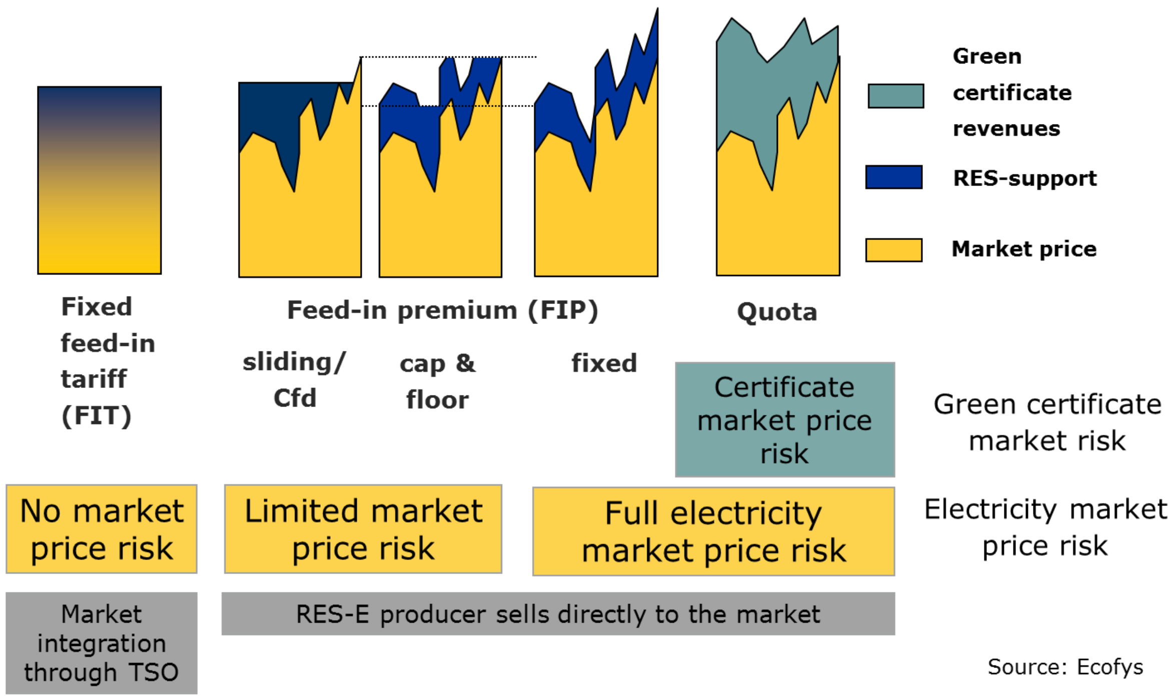

Figure 1: Different types of support instruments (Source: Ecofys)

With the increasing share of renewables, an increasing number of EU countries use FIPs as an optional or the main instrument to support renewables. FIPs are currently applied as alternative option to FITs in the Czech Republic (only for existing installations), Germany and Slovenia and as the main support instrument in Denmark, the Netherlands, Estonia, Finland and Slovakia. In the past also Spain used FIPs. The UK will use FIPs as main support instrument from 2014 that will eventually replace the existing quota system. Italy uses FIP for PV but changes in the system are expected. In the following, some examples of FIP systems are explained in more detail.

2.1.2 International experiences

Spain

The Spanish FIP system was suspended in 2012 and finally abandoned in 2013. Nevertheless, the Spanish case is used to explain the feed in premium with a cap and floor as Spain was the first European country to introduce a feed in premium as a support option 1998[1]. Under this decree, generators were allowed to choose between the fixed

[1] With Royal Decree-Law 1/2012 (27 January 2012) all economic incentives (feed-in tariffs, premiums, etc.) for the production of electricity from new installations using renewable energies (i.e. all installations which on 28 January 2012 had not yet been registered in the Register of pre-assignment of remuneration) have been suppressed. Equally, the procedure to register in the Register of pre-assignment of remuneration has been suspended (Art. 1 Royal Decree-Law 1/2012).

and the premium tariff for each year. While under this first decree, also plants under the premium option sold their electricity to the distributor, a modification (Royal Decree 436 of March 2004) first introduced the option for the plant operators to directly sell their electricity at the regular electricity market.

According to the premium option from RD436, RES-E generators could sell their electricity on the market, managed by the Spanish market operator (OMEL) or directly to customers through bilateral contracts or to traders through forward contracts. The overall remuneration consisted of the market electricity price (or the negotiated price, respectively) and the additional tariff components including a premium and an incentive for participation in the market (Ministerio de Industria y Energía 1998, Art. 23ff) and (Ministerio de Economía 2004, Art. 22ff). Many renewable plants chose the premium option (e.g. 99.8% of wind power plants in 2008) due to a considerably higher remuneration under this option. Rising electricity prices and the involved windfall profits for renewable plants under the premium option led to the introduction cap and floor prices in 2007 (Ministerio de Economía 2007)[2].

Under a feed-in premium with cap-and-floor (including a reference premium, a cap and a floor) there are four different situations leading to a different premium level and remuneration:

- As long as the sum of the electricity market price and the reference premium amounts to less than the minimum limit (floor), the overall remuneration level is equal to the minimum. The resulting premium is calculated as the difference between the minimum level and the electricity market price. In this situation, the overall remuneration level is constant whereas the real premium adapts depending on the electricity market price.
- If the sum of the electricity market price and the reference premium ranges between the minimum and the maximum limit (the cap and the floor), the reference premium is paid in addition to the electricity market price. Thus, the overall remuneration level increases, whilst the real premium is constant.
- Until the electricity price exceeds the cap price, the overall remuneration level corresponds to the cap and the real premium is calculated as the difference between the cap and the electricity price. The overall remuneration remains constant and the real premium declines.
- If the market electricity price exceeds the cap, no premium is paid and the overall remuneration is equal to the electricity market price.

The described calculation mechanism for the premium guarantees the RES-E producer a minimum income providing investment certainty for RES-E-projects on the one hand and cuts off windfall profits that have occurred due to rising electricity prices without a technology cost increase on the other hand. The Spanish feed-in system was

[2] Also before 2007, o PV plants were using the premium option as the minimum plant size was set to 100kW and most PV plants are smaller.

subsequently further developed in different decrees. The premium with cap-and-floor remained however an important mechanism.

Czech Republic

In August 2005 the Czech Republic introduced a *premium option* as an alternative to the already existing *fixed feed-in tariff*. Since January 2006 RES-E generators can decide to sell their electricity to the grid operator, receiving a fixed overall tariff, or alternatively offer their electricity directly on the market. In this case, a fixed premium called *green bonus* is paid on top of the market price. For power plants using co-firing of biomass and fossil fuels only the new premium option is applicable. The decision to use one of the alternatives is valid for one year. In order to encourage participation in the market, the level of the premium is chosen in a way that the overall remuneration of this option is slightly higher than in the case of a fixed tariff option. The fixed tariffs and the green bonus are adjusted annually by the *Energy Regulatory Office*, which takes into account the development of the different technologies and the market needs. (Energy Regulatory Office 2005) and (Parliament of the Czech Republic 2005). Since 2014, the support for renewables in the Czech Republic has been suspended due to rising costs.

Slovenia

Another country that applies a system with fixed tariffs as well as premium tariffs is Slovenia. The RES-E support scheme came into force 12 July 2009. RES-E plants with a capacity > 5MW and CHP plants with a capacity < 1 MW are supported via a FIP, smaller plants can chose between the fixed and premium options. Plants under the premium option as in the Czech Republic receive a fixed premium on top of the market price. The premium is calculated annually using a predefined reference market price (MP), technology-specific reference costs (RC) and a factor (called B-factor; B) which differentiates between different plant sizes according to the formula Premium = RC – MP*B.

Germany

In Germany, a sliding premium was introduced as an optional support instrument for renewables in 2012. Renewable plants can currently choose between support under the FIT and under the FIP. From 2014, biogas and biomass plants with a capacity > 750 kW will only be eligible for the premium option. From 2016 onwards, only small RES-E installations (≤100kW) can receive the fixed tariff. Plants under the FIP scheme receive a sliding market premium and a management premium on top of the market price. The management premium is directly included into the premium payment as of 2014.

The market premium is calculated ex post on a monthly basis. It is based on the difference between the fixed tariff and the average electricity market price in the respective month. The average market prices are adjusted by technology-specific factors for wind and PV as the prices that these technologies receive in the market are structurally different from the average price. Wind energy receives on average lower prices because high wind penetrations lead to low electricity prices in the corresponding period due to the merit-order effect. Solar PV receives on average higher prices as PV plants generate electricity during day time only when typically electricity demand is high and prices therefore as well.

The management premium is an additional premium meant to cover additional costs (e.g. IT infrastructure, personnel, forecasts and balancing costs) due to the direct marketing of electricity sold under the premium model. This additional payment is technology-differentiated.

Furthermore, operators of biogas plants are entitled to a flexibility premium if they increase their installed capacity without producing more electricity and thus can react flexibly to market signals.

Plant operators can choose between the options on a monthly basis. It is also possible to sell a percentage of the generated electricity under the premium option while the remaining share receives the fixed tariff. The plant operator needs to inform the grid operator in advance about these percentages.

Denmark

Denmark uses a premium system as major support instrument for renewables as well. In general, the system consists of a fixed premium which is paid on top of the market price. There are different regulations according to technology, plant operator and location.

Onshore wind plants that are not owned by utilities receive a fixed premium of 3.35 €c/kWh for 22,000 full load hours. Additionally, 0.31 €c/kWh are received during the entire lifetime of the turbine to compensate for the cost of balancing and such (comparable to the German management premium). For wind onshore plants owned by utilities a cap for the total remuneration consisting of the market price and feed-in premium is defined at 4.4€c/kWh. The feed-in premium is adjusted accordingly when this maximum remuneration level would otherwise be exceeded. An extra premium for management and balancing of 1.34 €c/kWh is paid for the entire plant lifetime.

In addition, offshore wind turbine premiums differentiate between turbines owned by utilities and others. Utility-owned offshore wind parks are entitled to a maximum remuneration for 10 TWh within 10 years, for utility-owned turbines the premium is paid until 42,000 full load hours are reached. The premium is determined in a competitive bidding mechanism.

The Netherlands

The Netherlands apply a premium system, the so called "SDE+", where the strike price is determined in a competitive bidding process (with technology-specific maximum prices). The premium is paid during 15 years at the date of commissioning of the plant and is calculated as the difference between the monthly average electricity price and the support level that projects achieved in the bidding rounds. Since the difference refers to the annual average price, producers can increase their revenues by selling more electricity when market prices are higher than the monthly average, that is, they receive market signals.

Finland

In Finland, a feed-in premium system was introduced in March 2011. The government sets a target price that plant operators shall receive per kWh of electricity produced. The feed-in premium is then calculated based on the difference between this target price and the three-month average of the electricity market price. By using the average electricity market price, plant operators receive market price signals and are encouraged to react to changes in the market price but investment security is still given to a certain extent.

The Finnish system includes an additional regulation to control overall support costs. If the average market price of electricity during the three months is less than 30 €/MWh, the feed-in premium will be equal to the target price minus 30 €/MWh. This regulation implicitly sets a technology-specific cap for the premium.

The feed-in premium for electricity produced using wood chips is based on the emission permits price. If the price for emission permits increases the feed-in premium level is reduced accordingly.

2.1.3 Short assessment of the premium tariff versus fixed tariff

2.1.3.1 Market compatibility

The premium option shows a higher compatibility with the principles of liberalised electricity markets than fixed feed-in tariffs: producers are responsible for selling and balancing their electricity directly on the market. It allows a stronger demand orientation of renewable electricity generation (at least with regards to non-intermittent sources) and therefore can be better integrated into the electricity market. Moreover, electricity producers using variable RES-E might optimise their planning of maintenance activities or seek for other ways to sell electricity at the wholesale market in times of low electricity demand (such as to industrial customers, etc.).

2.1.3.2 Investment risks

Depending on the detailed design of the premium option the risk for the RES-E producers increases compared to a fixed tariff. This is particularly the case for a fixed premium, where the premium does not depend on the average electricity price at the power market. In case of the sliding premium (as implemented, for instance, in Germany and Finland), where the premium is a function of the average electricity price, the investment risk increases only slightly, depending on the time frame used for the calculation of the reference price. In case of a fixed premium higher support levels are required to account for the additional risk premia, which then implies higher policy costs for the electricity consumers or tax payers. Therefore, the most promising option to minimise policy costs while exposing RES-E to market signals could be a sliding premium varying with the electricity market price or a top limit for the sum of market price and premium payment. A bottom limit could be introduced as well, in order to hedge the risk of strongly decreasing electricity prices for the RES-E producer. Such a cap and floor system was used e.g. in Spain.

2.1.3.3 Recommendation

The premium feed-in design offers different options to combine relatively high investment certainty with a higher demand orientation and market compatibility of RES-E generation. However, this argument mainly refers to dispatchable RES-E, since variable sources, such as solar and wind, can be influenced by market signals only to a limited degree. Since the low-risk investment conditions of a fixed tariff are crucial for many independent power producers and lead to a reduction of the cost of capital, it might be advisable to implement sliding feed-in premiums for variable RES-E and/or to let smaller RES-E plants chose between a premium and a fixed tariff option. When implementing this optional FIP, it is important to avoid windfall profits for those plants choosing the premium option.

A possible advantage for successfully implementing premium options is the availability of power purchase agreements (PPAs) for RES-E producers, as many producers will rely on intermediaries to sell their electricity in the market. In case PPAs are not yet available on the market (or only under unfavourable conditions), governments might ensure that a publicly backed counterparty offers back-stop PPAs (like e.g. in the UK).

Table 1 summarizes our recommendation for using either fixed FIT or FIP.

Table 1: Recommendation for market orientation of feed-in system design

Feed-in premium	Fixed feed-in tariff
• With increasing RES-E shares, the FIP should be preferred over the FIT in order to enhance market integration and demand orientation of RES-E. • For supply driven technologies such as wind and solar PV market risks should be reduced by using a sliding premium option, where the premium depends on the electricity price, or the use of cap and floor prices. We recommend calculating the reference price of the sliding FIP at least on a monthly basis, since shorter time horizons would lead to a similar output as fixed FIT.	• Recommended if electricity markets are not (fully) liberalised, or as exceptional application for less mature technologies with high investment risks or smaller installations, typically managed by private actors.

2.2 Definition of strike prices

One of the crucial elements in order to provide for a well-designed support instrument and to avoid overcompensation is the determination of the tariff level (or strike price), which influences both the attractiveness of a potential RES-E investment as well as the related support costs. Moreover, different options to determine the strike price perform differently in terms of market compatibility and limiting investment risks. One option is to set the tariff level based on the electricity generation costs from renewable energy sources. A second option is to determine the strike price based on the avoided costs (external costs and costs of electricity production using conventional technologies) induced by electricity generation using RES-E. A third option is to make use of tenders including competitive bidding processes or auctions. In this case the government usually sets the quantity of installed capacity but does not set the price as in conventional feed-in systems.

2.2.1 LCOE-approach

As the electricity generation costs vary according to the RES-E technology, a feed-in system design should provide technology-specific tariff levels. The most common approach in Europe to determine the tariff is the so-called 'levelised cost of electricity' approach (LCOE). LCOE can be interpreted as the present value of the total cost of building and operating a plant over its financial life (net present value – cash flow model), converted to equal annual payments (Klessmann et. al. 2013). Thus, it is the economic assessment of the cost of the energy-generating system including all the costs over its lifetime.

The LCOE is normally calculated by a straightforward cash flow model, which incorporates relevant technical, economic and fiscal variables. However, the level of sophistication and detail can vary significantly among models. The general philosophy of most policies using FITs or FIPs is that the support scheme should attract investors by providing a sufficiently attractive but not excessive return of investment (ROI). For that purpose typical projects are defined and general finance structures are assumed; the combination hereof intends to result in a "responsible" strike price from a societal perspective. Typically LCOE is calculated over 10 to 40 years lifetime and given in the units of currency per kilowatt-hour (e.g. €/kWh). LCOE is the ratio of total lifetime expenses versus total expected outputs expressed in terms of present value equivalent:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

- LCOE = Levelised cost of energy
- It = Investment expenditures in the year t
- Mt = Operations and maintenance expenditures in the year t
- Ft = Fuel expenditures in the year t
- Et = Electricity generation in the year t
- r = Discount rate
- n = economic lifetime of the system

Other factors that influence the power generation costs and therefore could be taken into account when the tariff levels are determined are:

- Other costs related to the project, such as expenses for licensing procedures
- Inflation
- Interest rates for the invested capital
- Profit margins for investors.

According to the expected amount of electricity generated, the estimated lifetime of the power plant and the expected ROI which is necessary to trigger the investment, a level of remuneration (or strike price) can be defined. Most EU countries that apply feed-in systems use this concept based on electricity generation costs to determine the applied strike prices.[3]

2.2.2 Avoided costs

A very different and somewhat unconventional approach to determine the strike price is to take into consideration avoided costs. These are the hypothetical costs of producing the same amount of electricity as from the renewable sources by using conventional technologies. These costs would include fuel costs, but also investment costs as well as expenditures for operation and maintenance. In addition, the avoided external costs can be considered when fixing the level of remuneration. External costs arise "when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted, or compensated for, by the first group" (European Commission 2003, p. 5).

Among others, the following possible external costs can be taken into account for electricity generation:

- Climate change
- Health damage from air pollutants
- Agricultural yield loss
- Material damage
- Effects on the energy supply security.

Only very few countries use (or used to) apply this methodology to define strike prices under a feed-in system, such as Portugal. A problem of this approach is that it does not consider the investor’s perspective (what internal rate of return is required to invest in RES-E) and may lead to over- or under-compensation from the LCOE perspective.

[3] A more detailed description on how to determine the electricity generation costs, using Germany as an example, is given in Chapter 15 of the EEG Progress Report 2007. http://www.bmu.de/service/publikationen/downloads/details/artikel/renewable-energy-sources-act-eeg-progress-report-2007/

2.2.3 Competitive price determination

Auctions are usually seen as a third kind of support instrument for renewables in addition to feed-in systems and quota regulations. However, auctions can also be used to determine the strike price of the feed-in tariff for a specific plant, a group of plants, a technology or all renewables. In most auctions, a strike price for each participating plant is defined (resulting in a fixed feed-in tariff or a premium payment in combination with direct marketing). The main objective of conducting an auction to determine the tariff level is to reduce the influence of lobby groups in the process of tariff-setting and to minimize the effect of asymmetric information between the plant operators and the regulator regarding the LCOE of a project.

The auction usually functions as follows: the government or responsible agency sets an amount of installed capacity of renewables that shall be installed in a specific time period. Certain conditions for the participation in the competitive tender process (e.g. regarding company profiles, permits, technological requirements) are defined. In most cases, participants bid certain strike prices that they need to make their project viable in a certain period of time (which is either pre-determined by the auction organizer or part of the bid). The auctions are mostly either organised as sealed-bid pay-as-bid auctions or as descending clock auctions with uniform pricing. In the former option, successful auction participants receive the strike price offered in their bid (pay-as-bid auction). In the latter option, they receive the resulting uniform price, whereby usually the highest selected bid sets the strike price for all selected bids.

2.2.4 International experiences

LCoE approach: Determination of feed-in tariffs and premiums in Germany

Until 2011 in Germany renewable electricity was supported with a fixed feed-in tariff. A sliding premium was introduced as an optional support instrument for renewables in 2012. The sliding premium means that the premium payment on top of the wholesale market price is adjusted (thus, not fixed) in order to reduce remuneration risks for plant operators. Between 2012 and 2015 renewable plants could/can choose between support under the fixed feed-in tariff and under the feed-in premium. From 2016 onwards, only small installations (≤100kW) can receive the fixed tariff. Plants under the premium scheme initially received a market premium and a management premium on top of the market price (Klobasa et al. 2013). It is meant to cover additional costs (e.g. IT infrastructure, personnel, forecasts and balancing costs) due to the direct marketing of electricity sold under the premium model. This additional payment was technology-differentiated. Since its recent revision (EEG 2.0), that has been approved by parliament (Bundestag) end of June 2014 and has come into force on August 1, 2014, the management premium is directly included into the tariff. Furthermore, operators of biogas plants are entitled to a flexibility premium if they increase their installed capacity without producing more electricity and thus can react flexibly to market signals.

In principle, LCoE calculations used for the determination of the fixed tariff and of the premium are the same. However, the obligatory participation in the premium model for most of the RES-E power plants introduced in the new EEG makes the translation of LCOE into strike prices more complicated. For instance, additional income streams from selling heat or the consideration of own consumption make the translation into tariffs even more complex. The determination of feed-in tariffs and premiums in Germany is based on cost calculations provided by the periodic evaluation reports. For calculating LCOE, the net present value (NPV) is calculated in a first step and then this NPV is converted to an annualised payment (Staiß et al. 2007). Taxes and possible income from other support mechanisms than the feed-in scheme are not taken into account, since the estimation of the tax rates depends on the individual ownership structure and cannot easily be generalised (Staiß et al. 2007).

For calculating LCoE in the most recent progress reports of 2014, assumptions for working average costs of capital are differentiated according to combinations of the technology, plant sizes and the prevailing investor structure in order to reflect different risk profiles (see Table 2). The share of equity and debt has partially been identified based on surveys (sewage, landfill and mining gas, Solar PV).

Table 2: WACC assumptions for LCoE calculations in EEG progress reports 2014

Technology	Sewage, landfill, mining gas	Biomass and biogases	Geothermal	Solar PV	Hydro	Onshore Wind	Offshore Wind
WACC	6.5%	6%	8.9%	4.3–4.4%	4.7–6.8%	4.6%	8.1%

Source: Interim progress reports 2014. Available at: http://www.bmwi.de/DE/Themen/Energie/Erneuerbare-Energien/eeg-reform.html

Also data sources for cost calculations in the German progress reports differ according to the respective technology. In general technical parameters and cost assumptions including investment, O&M costs, fuel costs, etc.) are based on expert knowledge and experiences of project partners and publicly available cost data (Staiß et al. 2007). For some technologies such as Solar PV, cost estimations rely mainly on public sources and analyses of raw material and component price development (e.g. silicon, wafer, modules, inverter) (Kelm et al. 2014). For other technologies the available data is supplemented with stakeholder surveys, as e.g. in the case of wind energy, where a survey on the different cost components was realised among manufacturers, project developers and wind farm operators in spring 2013 (Falkenberg 2014). In total 155 companies and institutions have been consulted for the survey on wind energy costs (Falkenberg 2014). Results of this survey have been compared with previous studies and data from literature in order to guarantee plausibility of survey results.

Tariffs are not only differentiated according to each technology but also depending on the plant type and size and in case of onshore wind on the location. In case of onshore wind this means that plant operators receive a fixed FIT (8.9 €c/kWh in 2012) during the first five years after the plant has started operating. The German Renewable Energy Act ("Erneuerbare-Energien-Gesetz", EEG) defines a *reference wind turbine*, which is located at a site with a wind speed of 5.5 m/s in an altitude of 30 meters. This reference turbine would generate a so-called *reference yield* in a five-year-period. If a wind turbine produces at least 150% of this reference yield within the first five years of operation, the tariff level will be reduced to a base tariff (4.87 €c/kWh for plants installed in 2012) for the remaining 15 years of support. However, for each 0.75% the generated electricity stays below the reference yield, the higher starting tariff will be paid for two further months. In theory, this means that the use of wind energy to generate electricity is not restricted to locations with very good wind conditions but that sites with less favourable conditions can also be exploited. In practice however, it was observed that the German system does not lead to a strong differentiation between locations as most locations are classified as low resource locations and thus receive a high tariff under the current scheme.

In Germany, the FIT and FIP rates for RES-E remain constant in nominal terms over the lifetime of the power plants. Thus, there is no inflation correction, meaning that the tariff implies an indirect digression over lifetime corresponding to the inflation rate.

In its extensive progress reports, LCOE calculation methodology and assumptions are made transparent on a high level of detail. However, although the actual tariff setting procedure is based on the LCOE calculations, the detailed methodology of converting costs into feed-in tariffs is not made publicly available. In addition, proposed tariffs have to pass the parliament and are therefore affected by political decisions. The German strike price setting process partly serves as an example for best-practices in particular due to its high level of detail regarding the periodic analysis of generation costs and to the use of surveys in order to estimate cost components. However, this involves considerable efforts in terms of costs, which might not be possible for all Member States. Participatory elements are included, but restricted to the direct stakeholders. One main point of criticism is the lack of transparency regarding the translation of LCOE calculations into strike prices. Opportunities for lobbying of tariffs through the respective industries during the political approval process may weaken the initial approach of setting tariffs on a purely objective or scientific basis.

LCoE approach: Feed-in Tariff with Contracts for Difference in the United Kingdom

In January 2014, the UK government introduced a sliding feed-in tariff with Contracts for Difference as a way of supporting investment in low-carbon electricity generation. CfDs are contracts that provide long-term electricity price stability to developers and investors in low-carbon generation. Generators will receive the price they achieve in the electricity market plus a "top up" from the market price to an agreed level (the "strike price"). This "top up" will be paid for by consumers. Where the market price is above the agreed level, the generator would be required to pay back and thus ensure value for money and greater price stability for consumers. It is important to note that while the strike price is closely related to LCOEs, it will ultimately be determined in a competitive bidding procedure: Once applications for support have been submitted, National Grid evaluates them, to see if allocation would be constrained. If there is sufficient budget for all projects, unconstrained allocation will apply, and all projects will receive the administratively defined Strike Price. However, if there is insufficient budget, constrained allocation will apply and an auction will be implemented. In this case, administratively defined strike price serves as a ceiling price for the auction.

The initial estimation of strike price is based (in part) on the levelised cost of energy for the technology in question. However, the initially defined strike prices could be higher or lower compared to the levelised costs for a number of reasons. The elements that are incorporated in the strike price setting process are transmission losses (the strike price is increased to account for this), existing Power Purchase Agreements (the strike price is increased when generators are not able to sell their electricity at the reference price), CfD contract length (the strike price should be increased when the CfD is set at a shorter period than the operating life of a project) and other policies (the strike price is reduced to account for the Levy Exemption Certificates of 5 £/MWh) (DECC, 2013).

Draft strike prices have been published for the first time in the draft Energy Market Reform Delivery Plan of June 2013. This plan has been subject to a public consultation round from August to October 2013. Over hundred responses have been received from a wide range of individuals and organisations including generators, suppliers, consumer organisations and environmental groups. The responses have been analysed and some changes have been included on a number of key assumptions. Final decisions on strike prices for renewable technologies for the period 2014/15 to 2018/19 have been formally published by DECC in December 2013.

The UK system operator National Grid provided evidence and analysis to the government to inform its decisions on CfDs and the capacity market. The National Grid launched a Call for Evidence (CfD) that invited all stakeholders to come up with most recent and relevant technology costs and economic assumptions for setting strike prices. The results of the National Grid Call for Evidence were combined with the generation cost data collected by DECC (DECC, 2013) to produce the aggregated cost information utilised in the modelling.

Levelised cost estimates for all cases have been calculated using the DECC Levelised Cost Model. Assumptions and results are published in the Electricity Generation Costs report of DECC (DECC, 2013). Levelised costs estimates for a number of different cases are considered in the DECC report. These cases are presented in the table below.

In calculating electricity generation costs, DECC makes a distinction between First Of A Kind (FOAK) technologies and Nth Of A Kind (NOAK) technologies. FOAK technologies do not have the advantages of learning from earlier projects and correspondingly experience higher costs.

Table 3: Different project types included in LCOE calculations

Case No.		
1	Projects starting in 2013	All at 10% discount rate. Technologies are mixture of FOAK and NOAK
2	Projects starting in 2019	
3	Projects starting in 2014, 2016, 2020, 2025 and 2030	

Costs are calculated over the full lifetime of the plant. This includes pre-development, construction, operation and decommissioning. Decommissioning costs are treated as an additional cash flow charge, a so-called "provisioning fund" that is treated as an operational cost on output generated. The assumption is that the provisioning payments will accumulate over time to provide a fund that will be the appropriate (DECC, 2013).

Levelised costs estimates are highly sensitive to the underlying data and assumptions used including those on capital costs, fuel and carbon costs, operating costs, load factor and discount rates. As such it is often more appropriate to consider a range of cost estimates rather than point estimates. Low, medium and high values are included for all project timings, some technical data, all capital costs, operating costs, CO_2 transport and storage costs, fuel prices, carbon price (DECC, 2013).

Levelised cost estimates of technologies are compared at a 10% discount rate, which is considered neutral in terms of financing and risk (DECC, 2013).

As mentioned above, levelised cost of electricity is only one input factor for the setting of strike prices. Other key assumptions include fossil fuel prices, effective tax rates, PPA discounts and maximum build assumptions. All are listed in the UK government report 'Electricity Generation Costs' (DECC, 2012). The levelised costs are calculated by DECC's Levelised Cost Model.

The levelised cost estimates given are generic, rather than site specific. For instance land costs are not included in the estimations and although use of system charges are included, they are calculated on an average basis (DECC, 2013).

Some cost elements not explicitly mentioned in the EC guidance, but included in the DECC cost methodology include: insurance costs, connection and Use of System (UoS) charges and CO_2 transport and storage costs. Furthermore, costs of grid connection for increasing amounts of renewables and providing back up to a grid which relies more on intermittent power are not included in the levelised cost calculations.

DECC used a number of different sources to compile the generation costs for renewable and non-renewable technologies. Cost data of renewable energy technologies have been drawn from nine different sources of information (DECC, 2013). For both renewable and non-renewable technologies, the DECC report includes the data sources used.

Regarding its transparent process and the related stakeholder involvement the definition of strike prices in the UK appears to follow best practices for LCOE calculations. The lack of differentiation of sites and plant sizes however, might make LCOE calculations and according strike price setting less precise. Calculating the LCOE in the UK serves a twofold purpose: if there is more demand for support than available support budget, an auction is implemented and the LCOE calculations serve to set the ceiling price. If there is no scarcity in support budget, the administratively defined strike price is provided to the applicants.

Tariffs based on avoided costs in Portugal

The Portuguese concept to determine the tariff levels was based on the avoided costs due to RES-E generation. RES-E producers receive a payment that is calculated by a special formula on a monthly basis. The elements of the formula represent different factors that influence the costs avoided due to the electricity generation from RES-E. They include the following:

- A fixed contribution on the plant capacity to reflect the investment for conventional power plants that would have to be built, if the RES-E plant did not exist.
- A variable contribution per kWh of electricity generated that corresponds to the power generation costs of those hypothetical conventional power plants.
- An environmental parcel corresponding to the costs for CO_2 emissions prevented due to RES-E generation, multiplied by a technology-specific coefficient.
- A factor that represents the avoided electrical losses in the grid due to the RES-E plant.
- Adjustment to inflation.
- Different tariff levels for electricity generated during day and night time.

This approach is interesting in terms of calculating the value of RES-E deployment in a broader sense. However, using external costs to derive the strike price it is problematic, because strike prices should in principle be just sufficient to trigger RES-E deployment, but avoid windfall profits on the other hand.

Competitive price determination: SDE+ in the Netherlands

The Dutch SDE+ is a sort of auction scheme, in which RES-E generators can apply for a sliding premium. The SDE+ opens in a number of sequential auction rounds that represent increasing support levels (ascending clock principle). However, while the SDE+ is a competitive bidding process, each year, the Dutch government pre-defines the strike prices (so-called base rates) per auction round and the maximum eligible strike price per technology (which thus has the function of a technology-specific ceiling price). These maximum prices per technology are predefined in an administrative process based on LCOE calculations.

The SDE+ provides a sliding feed-in premium covering the difference between the strike price and the reference electricity price, which is determined annually. Different price indices are used to calculate the reference price, such as electricity prices for base and peak load, natural gas prices and derivatives (ECN, 2013).

ECN and DNV GL annually advise the Dutch ministry on the level of the strike prices (the production costs of renewable electricity, renewable heat and green gas) for the categories prescribed by the Ministry. Each year, these institutes calculate the estimated costs (the LCOE) of renewable energy projects in the Netherlands to be realised in the year ahead.

A consultation round and external review are part of the tariff setting process. The draft version of the advice on strike prices is subject to a consultation round with market parties. There is consensus between the government and stakeholders for using the LCOE-model, which is based on a simplified cash-flow model. Discussions often relate to the estimation of techno-economic and financial parameters in the model.

In the open consultation round market parties are invited to provide their written comments on the draft advice within three weeks. After addressing the comments of market parties, the final advice is sent out for an external review. Latest external reviews on the base rates were conducted by Fraunhofer ISI in 2012 and the Institut für Energie- und Umweltforschung in 2013. The external review focuses on the process, the advice and the way ECN and DNV GL have included the market responses.

The definitive strike prices are sent to Parliament for adoption. Mostly, the SDE+ is adopted in line with the advice. After approval, the Ministry decides on the opening of the scheme for the subsequent year, on the categories to be opened and on the strike prices for new allowances for the year ahead.

The related LCOE calculations are done on basis of OT-model (Onrendabele Top / 'financial gap') of ECN[4]. The OT-model is a spreadsheet-based cash flow model and used for doing the financial gap calculations. The cash-flow model provides for the annual estimation of all project expenses, revenues, tax obligations or benefits and payments to capital providers. The individual annual cash flows are discounted to a single net present value (NPV). LCOEs (Euro/kWh (electricity), Euro/GJ (heat) or Euro/Nm^3 (biogas)) are calculated from the discounted cash flows (Euro) and the discounted energy production. Unlike conventional cash-flow models the OT-model does not calculate the internal rate of return (IRR) of a project, but it calculates the LCOE as a function of the cash flows and a minimum required return on capital. As a result the internal IRR is equal to this required return on capital (ECN, 2003)[5].

4 Downloadable at https://www.ecn.nl/projects/sde/sde-2014/

5 Return on equity = 15%, return on debt = 6%

In projecting the subsidy base rates, a standard return on capital is presumed with a nominal weighted average cost of capital (WACC, post-tax) of 6-8% per year, based on an interest rate of 5-6%, a required return on equity of 15%, and a debt/equity ratio of 80%/20% (ECN, 2011)[6]. In 2013, the Ministry asked ECN and DNV GL to assume a total financial return of 7.8%. This return is considered to be a reasonable compensation for the total risk of the project. It should also capture the project preparation costs.

From 2014 onwards, projects that apply for the SDE+ subsidy will no longer be eligible for the Energy Investment Allowance (Energie Investeringsaftrek, EIA) tax relief programme. Therefore, possible benefits from the EIA scheme are not included in the calculations anymore (ECN, 2013). The benefits from the green soft-loan scheme are deducted from the base rates to the extent that these benefits apply generically to a category. The green soft-loan scheme assumes an interest benefit of 1% (ECN, 2013). The pre-set 6% interest on the loan changes to 5% in case green financing applies. The duration of the loan and depreciation periods are assumed to be equal to the subsidy duration. For the biomass categories, the subsidy duration is set to 12 years, for all other categories the subsidy duration is 15 years.

The SDE+ has some degree of technology differentiation for the maximum strike prices, but size differentiation is limited. The SDE+ has five main categories (biomass, geothermal, hydro, wind and solar) and is further differentiated on technology level. In 2014, maximum strike prices were defined for 58 different technology subcategories (see OT-model).

One of the major changes of the SDE+ scheme was the introduction of wind differentiation as of 2013. The scheme differentiates maximum strike prices according to the size of the wind turbines and the wind conditions at the project site. Table 4 shows the differentiation for wind for the 2014 SDE+ scheme. For onshore wind three subcategories are defined, namely onshore wind, onshore wind >6 MW and wind in lake. Further to this, onshore wind knows three different wind classes, characterized by different wind speeds. Wind turbines located at sites where wind conditions are less favourable will lead to less full load hours. For such wind projects the established maximum strike prices will be higher.

6 ECN (2011) Cost-benefit analysis of alternative support schemes for renewable electricity in the Netherlands

Table 4: Onshore wind differentiation (ECN, 2013)

Subcategory	Subdivision	Wind speed at 100 meters (m/s)
Onshore wind	Stage I	8.0
Onshore wind	Stage II	7.5
Onshore wind	Stage III	7.0
Onshore wind ≥ 6MW	-	8.0
Wind in lake	-	8.0

The data gathering and rate-setting processes are highly transparent. Initial efforts to fill the OT-model with data are with ECN and DNV GL, but market parties are invited to come up with proposals to adjust the data that are in the public spreadsheet. The calculation method for the base rates is visible from the spreadsheets.

In terms of transparency of the process to define the strike prices, the Dutch model appears to perform very well. Also the calculation of the LCOE seems appropriate and straight forward. Moreover, the SDE+ combines a transparent process of LCOE-based maximum strike price definition with a competitive bidding process, thereby increasing market compatibility. However, this should not be mistaken with a good performance of the SDE+ as such, since the effectiveness of the support scheme and its dynamic efficiency (in terms of bringing more costly technologies into the market) are somewhat problematic (which is however, beyond the scope of this report).

2.2.5 Short assessment of concepts to determine the tariff level (Best-practice)

2.2.5.1 Market compatibility

In terms of pure market compatibility, neither the LCOE approach nor the avoided external cost approach reflects market principles in the definition of strike prices. However, the LCOE approach, much more than the avoided costs approach, aims to reflect the investor’s perspective by estimating actual production costs and determining strike prices close to LCOE. The competitive bidding process evidently performs better in terms of market compatibility. The competitive bidding process introduces a market mechanism into the allocation of support and the determination of strike prices. However, depending on the specific design of the auction, more or less market principles can be introduced. If an auction is designed in a technology-neutral way, it introduces competition between various technologies. However, technology-neutral auctions tend to delay the deployment of more expensive technologies, thereby reducing the longer term dynamic efficiency.

Moreover, in auctions the lower and upper limit for accepted bids can be defined, thereby reducing the risk of underbidding (floor price) and the risk of excessively high tariffs (ceiling price). However, both imply a limitation of market principles. Also, in case of limited competition, the ceiling price might lead to strategic bids close to the ceiling price.

In general, in particular early experiences with tenders in the EU in the 1990s and early 2000s were rather disappointing. For example, the tender regime in the UK under NFFO resulted in a low rate of implemented projects. Currently, auctions are used to determine tariff levels in the Netherlands for all technologies, if the application volume exceeds the available budget. Italy uses tenders as main mechanism to determine support level for large-scale power plants. Denmark and France among others use tenders for offshore wind; in France and Cyprus, the tariff level for solar PV is derived in an auction. Experiences from all countries are rather mixed and have shown that design details of the auctions are crucial in order to prevent unintended outcomes, such as underbidding or low implementation rates of selected projects.

2.2.5.2 Investment risks

The tariff level does not have a direct effect on the investment risk, but in practice, excessive support levels often lead to acceptance problems and the (sometimes retro-active) change of feed-in schemes. Therefore, the LCOE approach may help to create a stable policy environment for FIT or FIP systems. In case of the administrative determination of the strike price with the LCOE approach the investor knows upfront the strike price he will receive and usually is exposed to little risks of sunk costs.

In contrast, auctions introduce additional investment risks. Two types of risks are relevant here: first, the risk of not being granted access to support for a project and, second, the risk of non-implementation of a project, which might involve penalties for the project developer (and ultimately on the investor). Regarding the former risk, projects need to be pre-developed to a certain extent at the time of participating in an auction: this is necessary to meet potential prequalification criteria (as seen above) and in order to be able to calculate the required strike price to develop an adequate bidding strategy. This creates a "bidding risk": (sunk) costs occur which might not be recovered in case the bid is not successful and therefore not granted support. Regarding the second risk, the risk of non-implementation of a project, the implementation rate of projects is sought to be increased by implementing penalties. Such penalties have to be paid if projects are implemented with a delay or not at all. The project developer/investor carries this risk and has to account for it in the risk premium of the investment (the higher the risk of an investment, the higher the required return on investment). Hence, auctions introduce competition and improve market compatibility, but they introduce additional risk elements, which might in turn increase the required strike prices.

2.2.5.3 Recommendation

In terms of increasing market compatibility setting strike prices based auctions is certainly recommendable, if these are carefully designed. However, some caveats are important, e.g. the increased investment risks. These can be addressed through exemptions for actors who are less able to cope with risks such as small players. In addition, auctions need to be designed in a way that they reduce the investment risks to the extent that they allow the project developer to address those risks he/she can deal with best, but to avoid other risks that he/she cannot influence, as those will only increase support costs through increased risk premiums. Moreover, if ceiling prices are pre-defined, this should be based on a transparent and objective LCOE calculation, including sufficient stakeholder engagement.

Table 5: Recommendation for an approach to determining tariff levels

LCoE Approach	Competitive price determination
• If successfully applied: "appropriate" strike price to trigger investment while avoiding windfall profits. • Difficult to determine (lobby influence) and high effort of estimating costs • Can only be successful if adequate information (on generation costs) is available	• Tariff is not fully predetermined by the government but in a market-based process. Thus the tariff level is less prone to lobby influences. • Auctions should only be implemented if demand for RES-E support exceeds the available RES-E support budget/volume and if investors are well able to cope with associated investment risks. • Overall support costs might decrease, because competition between technologies is introduced. However, risk premium will be added.

2.3 Revising and adjusting tariffs over time

In order to make sure that tariff levels are still appropriate to reach energy policy goals and to adapt the tariff level to the learning effects, administratively defined strike prices have to be revised on a regular basis. In the case of auctions, tariffs are set in each auction, thus, they don't require tariff adjustments as such. Notwithstanding, also in auctions certain elements might have to be regularly revised, such as ceiling or floor prices or the bids themselves (as in the SDE+).

Different methods to revise the level of remuneration are applied in the EU Member States:

- Periodical revision and adjustment of tariffs.
- Automatic periodic tariff degression, e.g. on annual basis.
- Capacity dependent adjustment of tariffs.

Furthermore, tariff adjustments can be applied to new installations only or also to existing ones. Investment security is however much higher when only new plants are affected by tariff changes. Also, the exclusion of existing plants enables steeper tariff cuts for new plants. A further question is whether the tariffs are adjusted to inflation, in which case the tariffs of existing plants should be included.

2.3.1 International experiences

2.3.1.1 Periodical revision and adjustment of tariffs

Most countries revise the strike prices periodically. A degression mechanism may be introduced based on periodic reviews on current cost levels. However, this approach requires precise knowledge of cost levels and may involve high transaction costs by means of required studies.

In **Greece**, the revision of tariffs for PV power plants is undertaken more often than for other technologies, but PV power plant producers have 18 months to start plant operation at the initially agreed feed-in tariff. However, this comparatively long timeframe enables unnecessary windfall profits and may lead to inefficiencies in support for technologies with a very dynamic technology development.

In the **Czech Republic** the level of remuneration for new installations is set annually by the Energy Regulatory Office. These tariffs cannot decrease by more than 5% in relation to the level of those plants that started operation in the previous year. This rule causes stability and investment security. Moreover, feed-in tariffs for new and existing RES-E generation are adjusted, that is increased, annually according to the inflation from 2% up to 4%. (Parliament of the Czech Republic 2005, p. 6)[7].

In **Slovenia**, the feed-in tariff is based on the Reference Cost of Electricity (RCE) that reflects the overall annual cost of operating a RES-E/CHP plant, minus all revenues and benefits of operation. The RCE is further split up into a fixed and a variable part. The fixed part of RCE is adjusted every 5 years or more frequently in case of substantial change of conditions. The variable part of RCE is determined annually or more frequently on the basis of forecast of reference energy market prices.

In **Germany**, tariffs are based on the calculation of the LCoE, as explained above. The tariffs are reviewed regularly by the Ministry for Environment (BMU, until 2013) and the Ministry for Economic Affairs and Energy (as of 2014). The LCoE calculation takes place within the general process of evaluating the experience gained with each amendment of the main German support scheme, the "EEG". The German Renewable Energy Act (§65) requires a periodic review that has to be presented to the German Parliament. In these evaluation reports ("Erfahrungsberichte"), which are due every four years, the Ministry of the Environment (until 2013) and the Ministry for Economic Affairs and Energy (as of 2014) assigns external experts to evaluate experiences made with the EEG in order to adapt the EEG to the dynamic development of technology costs, support costs, etc. The "Erfahrungsberichte" contain a review of the feed-in tariff rates and an analysis of cost

[7] Note that the FIT and FIP have been abolished in the Czech Republic and that the future development of its support scheme is currently uncertain.

development and serve as a basis for modification and amendments of the EEG.[8] Around eight research institutes have been contracted to conduct the detailed bottom-up analyses on technology level. For 2014, six reports with a focus on a specific technology category have been published[9]. This shows the considerable effort, Germany puts into the periodic review of its Renewable Energy Act.

Before being translated into tariff adaptations, the draft of amendments is discussed in and has to be approved by parliament. Tariffs in Germany are thus not adjusted in a purely administrative process, but rather in a mix of an administrative and political process. There are concerns that this procedure opens up opportunities for lobbying through the respective industries, thereby weakening the initial approach of setting tariffs on a purely objective or scientific basis.

2.3.1.2 Automatic periodic tariff degression

In countries where a periodic tariff degression, e.g. on annual level, is applied, the strike price for new plants is reduced by a certain percentage every year. However, the remuneration per kWh for commissioned plants remains constant for the guaranteed duration of support. Therefore the later a plant is installed, the lower the reimbursement received. The tariff degression can be used to provide incentives for technology improvements and cost reductions. Furthermore, it reduces the risk of over-compensation. Ideally the rate of degression is based on the empirically derived progress ratios for the different technologies. Thus, cost reductions due to the experience curve effects are included in the policy and a continuous incentive for efficiency improvements and cost reductions for new plants is offered (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit 2008).

Among others, Germany, Greece, France and Luxembourg apply a support system for RES-E with a tariff degression. Subsequently these concepts will be described.

As mentioned above, in **Germany**, the main revision mechanism of the German EEG is the periodic revision of tariffs every four years. For tariffs paid for PV power plants, this periodic revision has been supplemented with an automatic tariff digression procedure since 2009. Tariffs are adjusted depending on the type of technology – reduction ranges from 1% for hydro plants to 7% for wind offshore (albeit starting only in 2018). For PV higher reductions are possible depending on installed capacities, as explained below.

In **Greece**, for small photovoltaic systems (<10 kWp) a tariff degression is applied. A pre-defined degression is foreseen for new entrants between 2012 and 2019 (Art. 3 Par.

[8] For the EEG 2011, evaluation reports for each technology can be found here: http://www.erneuerbare-energien.de/die-themen/gesetze-verordnungen/erneuerbare-energien-gesetz/eeg-erfahrungsbericht-2011/ (in German).

[9] Available at: http://www.bmwi.de/DE/Themen/Energie/Erneuerbare-Energien/eeg-reform,did=616706.html (in German).

3 FEK 1079/2009): 120 €/MWh (after 02/2014), 115€/MWh (after 02/2015), 110 €/MWh (after 02/2016), and a reduction of 5€/MWh per 6 months from 2017-2019.

In **France** an annual tariff degression is applied for new installations. However, only a certain percentage of the total tariff is subject to the degression (e.g. 60% of wind tariffs, 70% of geothermal tariffs). This part of the tariff is reduced by a predefined index, which takes into account the index of labour costs per hour and the index of industrial production costs. For PV, tariffs are reduced more frequently based on installed capacities.

In **Luxembourg**, a feed-in tariffs for new installations where reduced by a certain percentage annually. The degression differed by technology, varying between 0.25% and 9% (PV) per year. However, in 2014 tariffs have been increased to improve the attractiveness of investment in RES-E in Luxembourg:

- Wind energy (+13%): 9.4 €ct./kWh
- Hydro-Power (+ 56%): 13.3 – 16.4 €ct./kWh
- Biomass: (+11%): 12.2 – 16.1 €ct./kWh
- Biogas: (+31%): 15.7 – 19.7 €ct./kWh

2.3.1.3 Capacity dependent adjustment of tariffs

In a number of countries tariffs are adjusted based on installed capacities. This mechanism is most often used to adapt tariffs for photovoltaic installations as this technology has reached the fastest cost developments and high deployment in recent years.

After a 3 month moratorium for PV feed-in tariffs, **France** introduced a target installation capacity of 500 MW for PV plants in 2011. In addition, tariffs are adapted on a quarterly basis depending on the installed capacity in the previous quarter. Tariff degression ranges between 0% (if less than 5 MW were installed) and 9.5% (if more than 65MW were added in the last three months).

A capacity-based tariff adjustment for PV was introduced in **Germany** in 2009. It was decided that if the overall newly installed PV capacity in one year exceeded a certain amount (growing from 1500 MW in 2009 to 1900 MW in 2011) the degression would be raised by 1%, if it fell short of a certain value it would be lowered by 1% (Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit, 2008). Thus, this "breathing cap" links the tariff level to the capacity development occurred in the past. The growth corridor was amended in 2010, such that a reduction of the tariff by 1 / 2 / 3 / 4 % applies if an amount of 3500 / 4500 / 5500 / 6500 MW per year is exceeded. Despite this amendment, the installation rate for solar PV in Germany remained extremely high in 2010 and 2011. Therefore, in 2012 another amendment was introduced: in addition to the half-annual tariff degressions, tariffs for PV were reduced by 1% per month in order to avoid very high installation rates just before the tariff cut as in December 2011 when 3.5 GW of PV were installed in one month. It is important to note that with the EEG 2014, Germany introduced auctions to determine strike prices for ground-mounted PV.

2.3.2 Short assessment of the revision of tariffs

2.3.2.1 Market compatibility

The regular adjustment of strike prices relates in particular to administratively defined strike prices, which are less market compatible than, for instance, auctions. However, also auctions may require an adjustment of, for instance, ceiling prices.

The periodical review and adjustment of strike prices might reflect actual costs development more effectively than flat-rate approaches, such as the annual tariff degression or capacity-dependent adjustment of tariffs. In contrast, the capacity-dependent degression does somewhat reflect the market, since the decrease of tariffs depends on how the market has developed. In this sense, it also creates an indirect market signal to project developers who receive information about the supply of support and the demand for it. However, the price signal is difficult to predict and anticipate: the change in tariffs happens whenever other projects are already commissioned, thus, too late for new projects to reflect this signal into their decision.

2.3.2.2 Investment risks

The periodical revision and adjustment of tariffs introduces a risk during the early stage of the project development. In this stage such revisions might lead to uncertainty because it is not foreseeable to which extent tariffs will be reduced and thus, which ROI can be expected or, in some cases, whether projects will be bankable at all. The capacity dependent adjustment of tariffs also poses quite some investment risks, since the degression is not predictable by investors/project developers.

In contrast, a periodic tariff degression e.g. on annual level reduces investment risks considerably, since at all stages of the project development until its commissioning, investors can precisely determine the relevant strike price – thereby reducing revenue risks during the early stage of project development. However, fixed annual tariff degressions have often been insufficient to reflect the development of costs for certain technologies, foremost concerning the cost of PV. To avoid excessive windfall profits, but at the expense of lowering investment security, annual degression rates have been repeatedly combined with either ad hoc or regular, periodic tariff adjustments.

2.3.2.3 Recommendation

Among other factors, a stable policy framework with fixed FITs guaranteed over a long period may lead to high investment security and to high exploitation of RES-E, as has been seen for example in Germany and Denmark in the last years (and in Spain until some time ago). However, in order to guarantee the flexibility of the system to react quickly enough to changes in the costs for a technology or in the electricity price periodic revisions are foreseen in most feed-in systems. It is a challenge to provide a framework that is flexible enough but also leads to high investment security.

Depending on the cost dynamics of a technology periodic fixed and foreseeable degression rates can be useful to incorporate technological learning without substantially increasing investment uncertainty. Capacity-dependent but fixed and transparent degression might be used for technologies with fast and unforeseeable learning curves. Predefined degression rates might also be a good option to avoid industry influences when setting and revising the tariffs. However, the development of electricity generation costs is often not foreseeable and thus pre-established degression rates are problematic. Therefore, additional periodical revisions seemingly cannot be avoided.

Table 6: Recommendation for revising tariff levels

Periodical revision	Periodic tariff degression	Capacity-dependent degression
• Should be applied carefully, e.g. only as revision complementary to the annual or capacity-dependent degression • If applied, it needs to follow a transparent procedure.	• Can be useful for technology with a good estimation of future cost reductions. • Provides good investment security and is transparent. • It provides incentives to build a plant early in time. • Since the development of technology costs is not foreseeable for several years, annual degression rates have to be adapted after a few years.	• Provides an indirect market signal and is potentially suitable for technologies with steep learning curves.

3 Design features of quota obligation systems

3.1 General design features

This section deals with design features of quota obligation systems. Provided that several Member States (Italy, Poland, United Kingdom) have substituted their quota obligations with other support schemes, quota issues are not the key issue of this analysis. Instead we focus approaches to parameterize technology banding and price limits in technology specific quota systems. Initially, most of the quota systems followed a technology-neutral design, but high producer rents (windfall profits) caused by the combination of uniform pricing and strongly diverging technology costs led most Member States to modify quota design by making it technology-specific. In principle, this can either be done by assigning a different number of certificates to the technologies or by defining technology-specific targets (carve-outs). While avoiding windfall profits, the technology specificity involves further implications. Thus, technology banding adds complexity to the market and does hamper the accuracy and control of target achievement compared to technology-neutral quota. The prediction of certificate prices in banded systems is made more difficult, implying higher risk premiums from investors. Carve-outs maintain the advantages of predictable and controllable targets, but lead to less liquid markets.

Typically, quota systems involve higher price risks than feed-in systems, since power plant operator face variable prices for all remuneration components, the electricity market price and the certificate price. One measure to reduce the risk premium is to introduce minimum prices. Maximum prices or penalties are implemented in practically all quota systems in order to ensure target fulfilment. These penalties have to exceed the costs of the marginal technology required to meet the target.

Another relevant issue of the quota obligation is its path dependency when it has already been implemented. Provided that the revenues depend on demand of and supply for certificates, the continuation of stable financial support has to be organized when the quota obligation is substituted by another support scheme. Thus, the transition process of phasing-out a quota is more complex than of price-based support systems. This transition process can either be done by maintaining a certificate market with decreasing targets until the last plants achieve the end of support or by substituting the support of plants receiving support from certificate prices with an alternative payment. However, both options introduce a high level of uncertainty for plant operators.

Subsequently, we present experiences with implemented quota obligation systems, mainly focussing on the comparison of technology-neutral and technology-specific quota systems and one example of dealing with phasing out the quota system.

3.2 Calculation methodologies for banding factors and penalty levels – international experiences

Approaches to calculate banding factors and penalty levels are in principle similar to prime determination processes described in section 2.2. This section presents some examples of how to calculate the banding factors and analyses experiences made with the parameterization process.

Technology-banding in Flanders/Belgium

In the Flemish region in Belgium renewable energy sources are supported by a green certificate trading system (Groenestroomcertificaten). All renewable generation technologies are eligible for support, although there are differences regarding the duration of support. PV and wind installations can receive certificates during 15 years whereas biogas, biomass and CHP can receive certificates during 10 years. Green electricity certificates are allocated to plant operators by the Flemish regulatory authority (VREG). If electricity suppliers fail to meet the quota a fine of 100 EUR has to be paid for each missing certificate. The minimum price for green certificates is set to 93 EUR by the regulatory authority.

To receive certificates the plant operators have to submit an application to the regulatory authority VREG. If plants generate more than 1000 kWh the installations have to be certified by an authorized body. Each month green certificates are allocated to the plant operators according to the amount of green energy generated and the respective banding factors.

The number of certificates allocated to 1 MWh of electricity generated can be derived based on the banding coefficients of the corresponding technology. Banding factors are typically calculated once a year for most of the technologies and twice a year for PV. Existing banding factors are replaced if their value differs more than 2% from the new calculated banding factor.

The banding factors represent the ratio between the amount of Euro needed per MWh for the amortization of the installation ("onrendabele top") and the estimated average value of green electricity certificates. The calculation model is based on the Dutch "Onrendabele Top model" utilized in the SDE+ support scheme. The banding factor is calculated using the following equation:

$$BF = \frac{OT}{BD}$$

where BF represent the banding factor, OT represents the „onrendabele top" and BD represents the banding denominator (deler). The banding deler is currently fixed to 97 EUR.

The „onrendabele top" can be calculated with the following equation[10]:

[10] http://codex.vlaanderen.be/Zoeken/Document.aspx?DID=1019755&param=inhoud, Besluit van de Vlaamse Regering houdende algemene bepalingen over het energiebeleid [citeeropschrift "het Energiebesluit van 19 november 2010"].

$$NCW\ (OT) = -I + \sum_{t=0}^{Tb+Tc1} \frac{OKS_t(OT)}{(1+r)} = 0$$

with I: total investment, Tb: project period, Tc: construction period, OKSt: operational cash flow in year t, r: planned return on total investment.

In the following part assumptions and financial parameters are presented that are used for the calculation of banding factor for PV and wind installations:

(i) PV installations up to 10 kW

Regarding the calculation of a banding factor for PV installations with a capacity up to 10 kW a reference plant with 5 kW_{peak} is considered for the calculation. For the depreciation period of 15 years the amount of full load hours is assumed to be 897 hours per year. Investment costs include the purchase, installation and testing of the PV system. Maintenance costs are not considered for PV installations. Total investment costs are assumed to amount to 1960 EUR / kW_{peak} for the banding factor calculation of 2013 (Vlaams Energieagentschap 2013a, Vlaams Energieagentschap 2013b). Costs for the replacement of a transformer are set to 257 Euro per kW_{peak}. The above-mentioned financial parameters are based on historic data, on information provided by installers and on experiences of existing PV installations.

(ii) PV installations from 10kW up to 250 kW

As a reference capacity for PV installations from 10 kW to 250 kW an installation with 125 kW_{peak} is used for the banding factor calculation. 850 full load hours are assumed for these installations per year. The specific investment costs are estimated to be around 1440 EUR / kW and include the same components as for the above-mentioned 10kW installations. Total investment costs include grid connection costs and the specific investment costs.

Replacement costs for transformers add up to about 150 EUR / kW_{peak}, whereas yearly maintenance costs are estimated to 19 EUR/kW_{peak}. Again, parameters are based on gathered data and information provided by installers (Vlaams Energieagentschap 2012).

(iii) PV installations from 250 kW up to 750 kW

As a reference an installation with 400 kW_{peak} is used for the banding factor calculation. 850 full load hours are estimated for this category. Specific investment costs amount to 1280 EUR/kW_{peak}. Total investment costs including the costs for grid connection are determined to 1300 EUR/$kW_{peak.}$ Replacement costs for transformers are set to 150 EUR/kW_{peak}. The financial parameters are calculated based on historic data and were published in Vlaams Energieagentschap (2013a).

(iv) Wind installations with a capacity up to 4MW

The banding factor calculation for wind installations is similar to the PV installation, nevertheless there are small differences concerning the cost allocation. The full load hours for wind installations is derived by collected data from existing wind installations and is fixed to 2050 hours per year. The reference capacity for the calculation is a 2.3 MW wind installation. Financial factors considered are investment costs, operational costs and maintenance costs. Investment costs include the installation of the components, site costs, infrastructure, testing and the grid connection. Overall the total investment costs are estimated to be 1520 EUR/kW based on invoice data of the VREG database and information provided by installers (Vlaams Energieagentschap, 2013a).

Operational cost can be divided into fixed costs and variable costs. Fixed costs include insurance, management fees, communication, environmental coordination, internal consumption and amount on average 24 EUR/kW. Variable costs include costs for maintenance and in average add up to 25 EUR/kW. In total, operational costs per year are assumed to amount to roughly 51 EUR/kW. Assumptions and reference costs are based on historic data collected by the regulatory authority and information provided by installers and are valid for 2012/2013 (Vlaams Energieagentschap, 2013a).

Depending on the fuel and the installation capacity banding factors can vary. In attest banding factors are listed.

Table 7: Banding factors in Flanders

Technology	Banding Factor
PV	0.268 – 0.522
Onshore wind	0.777
Biogas	0.0409 - 1
Biomass	0.0496 - 1
Valid for installations constructed between 01.01.2014 – 30.06.2014	

Source: RES-Legal[11]

Technology banding in Romania

Quota targets in Romania are annually calculated and can be adjusted by the regulatory authority ANRE. The amount of green certificates is technology-related. The green certificates are tradable at prices between 27 EUR to up to 55 EUR per green certificate.

When the Romanian government introduced the support scheme it was described as the most generous support scheme existing and Romania earned a reputation as an attractive location for green energy investments[12]. At the same time, the generous

[11] http://www.res-legal.eu/search-by-country/belgium/tools-list/c/belgium/s/res-e/t/promotion/sum/108/lpid/107/

[12] http://www.nytimes.com/2013/05/22/business/energy-environment/romania-changes-course-on-renewable-energy.html?pagewanted=all&_r=0

support scheme was seen as weakness of the Romanian energy sector, since the incentive system incentivised overcapacity and could therefore affect the safety and stability of the Romanian power system[13]. The number of green certificates allocated to suppliers was up to 50% above European average (Pislaru, 2014). For example, PV installations were eligible to receive 6 green certificates per MWh, small hydro power installations were eligible to receive 3 green certificates per MWh. In combination with the achievable certificate prices between 27 EUR and 55 EUR, this led to considerable overcompensation for some capacities. Due to the favourable RES-E potential and the generous support scheme a large increase of RES-E was noticeable in Romania in 2011 exceeding the expectations of the government. As a consequence, energy prices increased and worries about increasing "energy poverty" (a large amount of the annual income is spent to pay energy bills) arose (Mislea & Leca, 2013).

To avoid an over-compensation of investors and increasing energy prices, the Romanian government decided to cut the number of green certificates and to hold back paying subsidies for several years[14]. The change in legislation was perceived to be a mistake without legal justification[15]. The number of green certificates allocated to PV installations was reduced to 3 certificates per MWh, small hydro power was reduced to 1 certificate per MWh[16].

As a consequence large RES-E investors such as Kronos withdraw green energy projects in Romania since there was no stabile framework given to plan long-term investments (Mislea & Leca 2013). After the change of legislation companies and investors started to target future investments in RES-E to other countries with a more stable policy framework.

It is not clear based how banding factors are calculated by ANRE and therefore difficult to say, if the number of green certificates is appropriate for each technology. The Romanian support scheme shows how important an appropriate way of banding factor calculation is. As a perquisite for an elaborated support of RES-E it is important to find adequate methodologies to derive banding factors. In particular, the overestimated banding factor in a first step and the subsequent abrupt change in the banding factor led to considerable costs and afterward to a loss of investors' confidence. Not only companies suffered from this approach but also the Romanian population since energy prices increased due to the miscalculation.

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13 http://oldrbd.doingbusiness.ro/en/5/latest-articles/1/893/priorities-for-the-romanian-national-energy-strategy

14 http://oldrbd.doingbusiness.ro/en/5/latest-articles/1/893/priorities-for-the-romanian-national-energy-strategy

15 http://www.nytimes.com/2013/05/22/business/energy-environment/romania-changes-course-on-renewable-energy.html?pagewanted=all&_r=0

16 http://www.euractiv.com/energy/czech-utility-alerts-romanian-ro-news-529913

Technology-banding in the United Kingdom

The United Kingdom chose a renewables obligation (RO) with a tradable green certificate market as its main support scheme for RES-E from 2002 to 2013. Initially, the British RO was implemented in a technology-neutral form, but technology-banding was introduced in spring 2009 to reduce windfall profits for more cost-effective technologies and to stimulate growth of more innovative technologies.

Next to the quota, the British government launched a FIT scheme for small-scale technologies in spring 2010. The validity horizon of the quota obligation was extended from 2027 to 2037 in 2010 to increase investment certainty and trigger more long-term investments (Kopp et al., 2013).

Nevertheless, the British government started to replace the RO by a feed-in premium scheme (Contract for Difference – CFD) in 2014, indicating that the implemented modifications of the quota obligation failed to live up to expectations of the British government.

Abolishing a quota system poses the question of how to continue support for existing installations. In the UK new plants may still apply for support under the RO until March 2017 and the quota obligation will run in parallel to the CfD system until 2037, allowing for revenues from certificate prices during 20 years after the last new plant enters into the certificate system. Thus, two parallel support systems are maintained in the UK during more than 20 years in the future. The continuation of the quota obligation requires an adaptation of the quota target in order to reflect the expected decreased participation in this scheme and to keep prices stable. All these changes in the UK illustrated the complexity of the transition process and the strong path dependency of quota systems when these are too phased out.

Experiences with technology-banding in the UK show that the design of the banding and the determination of the multipliers are crucial for the success of the banded quota. In principle, technology banding is an approximation to price-based approaches such as feed-in systems, as knowledge of RES-E-generation costs is required. Similarly, introducing banding in the British quota system has been partly perceived as abandonment of market-principles (Buckman 2011).

Banding factors in the UK were calculated based on RES-E generation costs at present and their outlook until 2020. A revision of the initial wind multiplier for offshore wind from 1.5 to 2 after a public consultation indicated some difficulties to adequately calculate costs and determine banding multipliers. According to Buckman (2011) revenues from banded certificates were still more generous for certain technologies such as wind onshore and landfill gas than for others. In addition, higher risk premia may be perceived in banded quota systems due to more difficulties in estimating the future certificate price (Johnston et al. 2008). The price depends on the degree of target achievement which is much more difficult to predict in a banded quota system.

Accordingly, stronger fluctuation of certificate prices could be observed since the introduction of banding.

Technology-banding in Italy

The Italian quota system which was introduced back in 2001 was replaced by a tender scheme for large-scale power plants as of 2013. At the same time smaller-scale applications still receive feed-in tariffs. Initially, first elements of technology-banding in Italy were introduced by differentiating the validity horizon of certificates for different technologies already in 2006. Afterwards tradable green certificates were allocated according to technology categories based on multipliers since 2008 until the end of the Italian quota system. However, only little technology differentiation through banding with multipliers ranging from 0.8 for biogas to 1.8 for ocean technologies was used. In general, the performance of the Italian quota obligation was characterised by high certificate prices - with average values ranging from 74 to 85 €/MWh between 2009 and 2012 – and low effectiveness for most of the technologies in particular in the earlier phases of the quota obligation (Steinhilber et al. 2011). Despite the less favourable banding factor the development of onshore wind has been stronger than in case of biomass in particular in the last two years of the obligation. Another problem observed in the Italian system was the non-existence of clear and explicit non-compliance penalties. Although sanctions in case of non-fulfilment exist in theory, there were only vague rules for monitoring compliance.

3.3 Short assessment

The performance of quota obligations strongly depends on its concrete design. If these are designed in a technology-neutral way, only the most cost-effective technologies are supported, leading to a high static efficiency in terms of generation costs. However, the associated dynamic cost efficiency is typically low, since most of the cost-intensive technologies do not receive sufficient support, whilst high producer rents may occur for the lower cost technologies.

3.3.1 Market compatibility

In general, quota obligations are highly compatible with market principles and competitive price determination. Introducing technology-specific elements can improve support conditions for more cost-intensive technologies and windfall profits for the more cost-efficient technologies can be reduced. At the same time experiences e.g. in Romania have shown difficulty to parameterise banding factors and the strong impact on support costs and investor confidence, if banding factors do not reflect actual generation costs. In addition, it is rather challenging to deal with cost reductions and the required adaption of banding factors over time. Similar to the design of feed-in systems, the introduction of technology-specific design elements requires a good knowledge of generation costs and potentials.

3.3.2 Investment risks

High risk premiums resulting from the uncertain development of the electricity and the certificate price typically increase policy costs. The introduction of technology-specific elements can further increase uncertainty about future prices. Existing price risks in both markets can be mitigated by concluding long-term contracts or by establishing floor prices for the certificate price. Alternatively, the quota target could include a so-called "head-room", meaning that quota targets can be increased, if prices fall under a certain threshold in order to maintain shortage of certificates.

3.3.3 Recommendation

In many countries, quota obligations have turned out to be an expensive instrument for supporting RES-E. Thus, we can only recommend using a technology-neutral quota if abundant RES-E-potential is available and if costs of the different technology options are similar.

Table 8: Recommendation for designing quota obligations

Technology-neutral quota	Quota with technology banding	Quota with carve-outs
• A technology-neutral quota seems only beneficial if abundant RES-E-potential is available and if costs of the different technology options are similar.	• In case of steeper cost-resource curves, technology banding is an effective way of avoiding windfall profits and providing support for less mature technologies. • However, several difficulties occur e.g. to parameterize banding factors of technology banding, Negative impacts resulting from a weak parameterisation process should be avoided.	• No experience with carve-outs is available in Europe. There is a high risk that the liquidity of the markets becomes too low, therefore they should only be considered in sufficiently liquid markets. Currently this option does not seem suitable for RES-E support in Europe.

4 Burden sharing of support costs (independent of support scheme)

4.1 Releasing the burden for energy-intensive industries

In the context of increasing policy costs for RES-E-support, the fair distribution of the resulting burden without adversely affecting the competitiveness of energy-intensive industries is very important in order to maintain public acceptance of RES-E-support. In particular the coordination of burden sharing approaches for the RES-E policy levies among final consumers needs increasing attention. Here particularly the rules for exempting energy intensive industry are of relevance in order to avoid distortions on the competitiveness of EU industries due to renewable energy support schemes.

The choice and the design of the applied burden-sharing approach depends in particular on the overall share of RES-E in the system and on the cost level of respective renewable energy technologies used in the system. Examples of how energy intensive industries may receive special treatment with regard to bearing RES-E-support costs are briefly analysed in section 4.2.

Funding may either come from a public budget (paid for by tax payers) or from a levy linked to the consumption level and included into the final energy price (financed by consumers). In the electricity sector most of the EU Member States distribute policy costs for RES-E support among all electricity consumers by imposing a levy per unit of electricity generated on top of the electricity price. In its proposal for guidelines on support schemes, the EC clearly states a preference for financing RES-E-support via levy (European Commission 2013) in order to make RES-E-support more compatible with European rules on state aid and the environmental polluter pays principle. According to European Commission (2013) almost all countries already finance their RES-E-support off-budget. Only Luxembourg and partly Belgium still use a state budget for bearing the main part of RES-E-support costs.

Several countries use exemptions or reductions for energy-intensive industries in order to maintain competitiveness of companies where electricity costs represent a significant part of total expenses. The preferred treatment of energy-intensive industries by granting exemptions or reductions of the required levy improves the international competitiveness of these industries, but increases the burden for the remaining consumers at the same time. Consequently, only companies who actually need an exemption or reduction to withstand international competition should be granted such privileges. Furthermore it has to be assured that distortions between different EU Member States in terms of the burden put on different industries will be minimised. Adequate criteria have to be defined to determine which companies should be exempted from or contribute less to finance renewables support. The EU regulations have been redefined in 2014 based on the new state aid rules (European Commission 2014). It can be expected that these regulations will cause a substantial pressure towards convergence between practices used in Member States today. Some of these current practices in

Member States are described in section 4.2 below and the new State Aid Regulations are summarised in section 4.3.

4.2 International experiences

The Netherlands

The former Dutch renewables support scheme SDE was financed through the state budget from 2007 until 2013. However, from January 2013, a levy on the energy bills of end consumers (households and businesses) was introduced to finance the follow-up programme SDE+. The distribution of the financial burden aims for 50% households and 50% businesses. It concerns a weighted average (estimated production and price for each kWh that is adjusted to meet the budgetary needs of that year and adjusted to meet the 50/50 distribution) established at the end of each year, for the next year. The levy is charged by the utilities and included in the monthly energy bills. Utilities are responsible for passing on the amount to the government. The levy is set until 2016 and increases every year to match the available SDE+ budget for the respective year. The following levies were agreed for 2013:

- Electricity: 0.13 €ct./kWh for 1 – 10.000 kWh, 0.17 €ct./kWh for 10.001 – 50.000 kWh and 0.05 €ct./kWh for 50.001 – 10 mln kWh;
- Gas: 0.23 €ct./m^3 for 0 -170.000 m^3 and 0.09 €ct./m^3 170.000 – 1 mln m^3, 0.03 €ct./m^3 1 mln – 10 mln m^3 and 0.02 €ct./m^3 > 10 mln m^3.

For households with an average electricity and gas consumption the levy was around 9 Euro per year in 2013.

Germany

In Germany, the burden for RES-E support is distributed to the electricity consumers via the EEG levy ("EEG-Umlage"). The German system provides exemptions from the EEG levy and from other charges or fees to selected groups of stakeholder for different reasons:

- First, energy-intensive industries are granted reduced fees or even exemptions from levies in order maintain their competitiveness
- Second, onsite electricity consumption of RES-E and CHP technologies is encouraged, by granting exemptions from the EEG levy.

The described privileges ultimately reduce the amount of electricity the burden is distributed over. This results in an increased burden for the remaining consumers. The regulations for relieving energy-intensive industries have been revised in each revision of the feed-in tariff and in particular in the revision of the EEG-2014, which implements the new State Aid Guidelines. Below we first show the regulations valid in the EEG-2012 and secondly list main amendments due to the EEG-2014.

Only companies with an annual electricity consumption of more than 1 GWh per year and a share of electricity costs exceeding 14 % of the gross valued added are eligible for a reduction in the EEG-levy. Thus, eligible companies have to pay the full levy for the first GWh of electricity consumed, whilst a partial exemption applies for up to 100 GWh. Between the 2nd and the 10th GWh, 10 % of the normal levy is due, whilst 1% of the normal levy has to be paid for electricity consumption between 11 and 100 GWh. Electricity consumption over 100 GWh per year pay a fixed rate of 0.5 €/MWh. In case the share of electricity costs in gross added value exceeds 20%, companies are fully privileged consumers and pay 0.5 €/MWh for the total amount of electricity consumed. This regulation also applies for railway companies. shows that in addition to the EEG-levy, energy intensive industries count on additional reductions in other fees, charges and taxes, including VAT, grid charges.

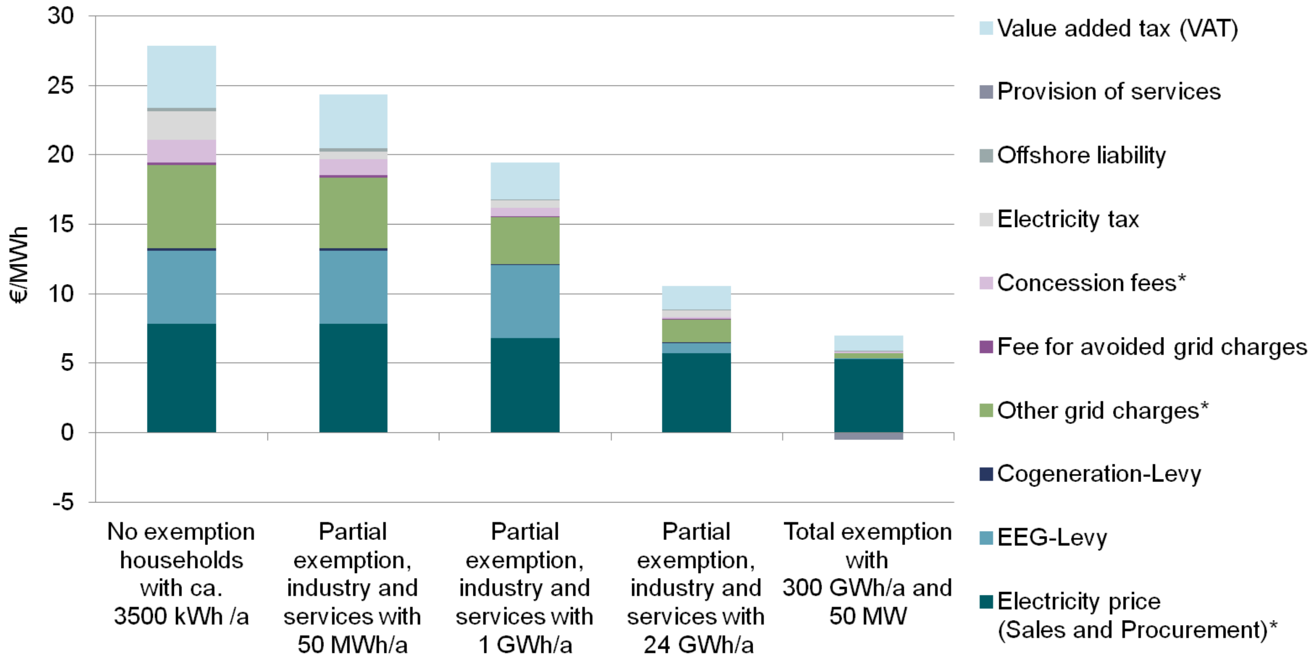

Figure 2: Components of electricity prices in Germany according to consumer type in 2013.

Source: Own illustration based on Bundesnetzagentur (2011)

With the revision of the EEG in 2014[17], which became operational on 1st of August 2014 the new State Aid Guidelines were implemented in the German support scheme for renewable electricity. This led to the following main changes:

- A list of eligible sectors, which is closely aligned to the one given in the State Aid Guidelines restricts the possibility to relieve companies to the corresponding sectors.
- This list differentiates between two classes of sectors with different degree of pressure on international competitiveness. Depending on this class companies with an annual electricity consumption of more than 1 GWh per year and a share of electricity costs exceeding 16 % or 20% of the gross valued added are eligible for a reduction in the EEG-levy.
- Privileged companies generally pay 15% of the EEG-Levy. For highly electricity intensive companies the level of the EEG-Levy can be reduced further to 4% / 0.5% of the gross value added (according to the "Cap" and "Super-Cap" defined in the State Aid Guidelines). In any case companies pay the full EEG-levy for the first GWh consumed and a minimum of 0.1 € cent / kWh for the remaining consumption.

Austria

Until the end of 2006, Austria used a levy per unit of electricity produced to finance the promotion of all RES-E with the exception of small-scale hydropower. The levy was defined according to the respective voltage level the electricity consumer was connected to. Thus, lower specific burdens were put on high voltage clients, typically energy-intensive industries. In 2007, the "*Ökostromgesetz-Novelle*" modified the existing regulation by dividing the burden in two main components:

- Fixed annual charge according to the grid level
  ("Zählpunktpauschale" until 2007, "Ökostrompauschale" as of 2012)
- Variable levy paid and passed on to consumers by electricity traders

Electricity traders are obliged to procure a certain percentage of their electricity at a predetermined increased price ("*Verrechnungspreis*"). This "*Verrechnungspreis*" amounted to 105 €/MWh for all RES-E plants (excluding small-scale hydropower) in 2009, 124 €/MWh in 2010 and to 127 €/MWh in 2011. A more recent modification from summer 2012 changed the attribution of the levy – which was part of the electricity price until 2012 – and included the levy into the network charges in order to increase transparency. In addition the fixed component has been increased, as shown in Table 9. The share of the variable components increased from slightly above 60% to around 72% (E-Control 2012).

[17] Gesetz für den Ausbau erneuerbarer Energien: http://www.gesetze-im-internet.de/eeg_2014/

Table 9: Consumers' contribution to financing RES-E support in Austria.

Grid level	Annual costs for RES-E support		
	2006	2007 – 2012 Zählpunkt-pauschale	As of 2012 Ökostrom-pauschale
Grid level 1 – 3 (110 - 380 kV)	3.25 €/MWh	15,000 €/a	35,000 €/a
Grid level 4 (Transformation from 110 kV to 10-30 kV)	3.82 €/MWh	15,000 €/a	35,000 €/a
Grid level 5 (10 – 30 kV)	3.82 €/MWh	3,300 €/a	5,200 €/a
Grid level 6 (Transformation from 10-30 kV to 400 V)	3.98 €/MWh	300 €/a	320 €/a
Grid level 7 (400 V)	4.64 €/MWh	15 €/a	11 €/a

Source: Own illustration based on E-Control 2006, §22a Abs 1 Ökostromgesetz idf Novelle 2009, §45 Abs 2 Ökostromgesetz 2012.

Denmark

Denmark passes additional costs resulting from the use of RES-E on to consumers through the *Public Service Obligation* (PSO) in terms of an additional levy on total electricity consumptions. This surcharge is determined on a trimestral basis by Energinet, the Danish TSO and varies with the consumers' electricity consumption. Consumers with an annual electricity consumption exceeding 100 GWh only have to pay a decreased levy. The levy is reduced for all the electricity exceeding 100 GWh covering costs of grid companies and the system operator for the provided services. In contrast to Germany, only a small number of companies – seven – are covered by this regulation.

4.3 Short assessment of burden sharing approaches in the context of the new State Aid Guidelines

The examples in the section above show the heterogeneity of approaches for burden sharing in EU Member States. The degree of relieving energy intensive industries depends on the total level of the levy and on the industrial structure of different countries. In particular many countries did not consider the actual impact of electricity costs on international competitiveness of different industries. Therefore, the EU Commission introduced new Guidelines on State aid for environmental protection and energy 2014-2020 in June 2014.

These guidelines require that "*the aid should be limited to sectors that are exposed to a risk to their competitive position due to the costs resulting from the funding of support to energy from renewable sources as a function of their electro-intensity and their exposure to international trade. Accordingly, the aid can only be granted if the undertaking belongs to the sectors listed in Annex 3. This list is intended to be used only for eligibility for this particular form of compensation.*" It has been argued however, that an even more restrictive approach should be followed for defining the "competitive position" of EU industries and therefore state aid should be granted to a more limited list of sectors (Agora Energiewende 2014).

In addition to the sector classification the European Commission suggests that additional reductions from costs resulting from renewable support, may be granted *"if the undertaking has an electro-intensity of at least 20 % and belongs to a sector with a trade intensity of at least 4 % at Union level, even if it does not belong to a sector listed in Annex 3."*

Regarding the costs that need to be covered by the companies eligible for compensation "*the Commission will consider the aid to be proportionate if the aid beneficiaries pay at least 15 % of the additional costs without reduction*".

4.3.1 Market compatibility

In general, the exemptions lead to lower market compatibility, but harmonised rules for relieving energy intensive industries can be expected from these new state aid rules. This will reduce distortions between the support schemes in EU Member States and therefore lead to increased market compatibility.

4.3.2 Investment risks

Regarding investment risks, the impacts of releasing energy-intensive industries from the burden resulting from RES-E support do not effect investors directly, but there are some indirect effects. Typically budget-based financing involves higher risk for investors, as budget cuts may lead to stop-and go policies and thereby make the planning phase for investors more difficult, since they have to anticipate that support may not be available anymore. Levy-based financing appears to offer higher investment security, but increasing levies can endanger public acceptance of RES-E-support and thereby even jeopardise the continuation of RES-E support. The relief of energy-intensive industries leads to better RES-E support acceptance for these industries on the one hand, but increases the burden for the remaining consumers.

4.3.3 Recommendation

Table 10: Recommendation for levies for energy-intensive industries

Releasing energy-intensive industries
• We recommend restricting exemptions and reductions carefully based on meaningful criteria defined to judge whether exemptions are required to main the competitiveness on international level. • Exemptions and restrictions should be limited as much as economically feasible in order to avoid acceptance problems. • The harmonised definition of criteria could help guarantee equal treatment of industries in all European Member States.

5 Coordinating design features of support schemes

5.1 Why coordinate policies in Europe?

Support schemes in Europe already show an increasing convergence towards the best practices outlined in this paper: countries with administratively defined support schemes tend towards FIPs to incentivize operational decisions according to market signals – quota schemes sometimes have been modified to include price floors to reduce price risks. However, other aspects of support scheme design in Europe remain fragmented.

Regarding feed-in systems, regulatory fragmentation remains for instance regarding how reference prices are calculated (e.g. yearly, monthly, daily, hourly). Moreover, the way strike prices are defined differently, for instance, regarding the LCOE calculation. Also auctions are applied in a wide variety of ways throughout Europe (reflecting the little experience with this instrument). Moreover, the way tariffs are revised (in case of administratively defined tariffs) differs heavily between countries.

Regarding quota obligations, the main differences in the applied systems are:

Quota obligations may be applied in a technology-uniform way or contain technology-specific elements. In the latter case this may either be realised by introducing multipliers defining how much certificates a certain technology receives or by a complete separation of markets per technology. Thus, several countries such as Belgium, Italy and the United Kingdom opted for introducing technology banding in their previously technology-neutral quota systems, whilst Poland and Sweden stick to their technology-neutral quota. In general, there is a trend in Europe of countries substituting quota obligations through alternative support schemes such as feed-in premiums combined with competitive bidding procedures (Italy, Poland, United Kingdom).

The differences observed imply two major problems: First, numerous support schemes differ from acknowledged best practices and this provides a sub-optimal balance between market compatibility and investment security. Second, differences in support scheme design are one cause for a fragmented market within Europe. However, creating the internal market implies to overcome this fragmentation which in turn requires greater convergence on support scheme design.

But how can this convergence towards best practices best be achieved? Again, two extreme approaches appear in the European context: Either support schemes and related regulations could be harmonised in a top-down manner e.g. initiated by the European Commission or they could be coordinated in a bottom-up approach, without any "interference" of the EC. Currently, a mixture of both approaches seems to be applied in Europe:

5.2 Current state of top-down coordination

For instance, already in the Renewables Directive 2009/28/EC, several aspects regarding support schemes have been "harmonised". These include the obligation of Member States to "introduce measures effectively designed to ensure that the share of energy from renewable sources equals or exceeds that shown in the indicative trajectory" (Art. 3), planning and reporting requirements (e.g. "National Renewable Energy Action Plans", progress reports from the Member States on a bi-annual basis) and the calculation method of the share of energy from renewable resources. Regarding Guarantees of Origin, the Directive harmonises minimum design criteria (e.g. with respect to their cancellation and the necessarily included information) (Art. 15). Also, Member States "shall ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources" and priority dispatch for electricity from renewables is obligatory for Member States (Art. 16). Articles 17 and 18 refer to harmonised sustainability criteria for biofuels and bioliquids, and the verification of their compliance with these criteria. Thus, the existing Directive has, to some extent, already harmonised parts of renewable energy policies, albeit without fixing a common or harmonised support scheme and without being very specific on most of the issues discussed in this report so far.

However, not only the RES-E Directive already harmonises certain elements. The recently published EEAG provide further legally binding prescriptions on how support schemes should be designed. This includes for instance the implementation of FIPs from 2016 onwards, thereby phasing out FITs for most of the renewable power plants (apart from installations <500 kW or 3 MW wind). Moreover, the introduction of competitive bidding schemes to determine strike prices for RES-E is expected as the default process: 5% of planned new capacity in 2015 and 2016 and full introduction of auctions from 2017 onwards is envisaged. Also, in principle the EEAG suggest technology-neutral support. However, they allow technology-specific auctions in a number of cases (e.g. the broad concept of "the need to achieve diversification"). Again, exemptions to the requirement of implementing auctions are possible for installations of <1MW (or <6MW of wind capacity). Thus, while the Renewables Directive 2009/28/EC defined first steps in coordinating in a top-down manner certain support scheme aspects, the EEAG seeks to further harmonise parts of renewable energy policies, but still without fixing a common or harmonised support scheme.

5.3 Why not harmonise support scheme regulations?

If we are able to identify best practices with respect to the balance between market compatibility and investment security, and if the RES-E Directive of 2009 and the EEAG of 2014 already "coordinate" (i.e. harmonise) part of support scheme regulations, why not simply harmonise all related regulation towards best practises? A full top-down harmonization of the discussed support scheme elements does not seem favourable for various reasons:

First, a lack of context specificity could lead to decreased effectiveness and efficiency of harmonised support. Since Member States have different geographical, legal, political, and market conditions in which renewable energy support schemes operate, the establishment by the EU of a harmonised support scheme without aligning or reflecting these context conditions could be less effective and efficient than locally-adapted national support schemes (Dårflot, 2004). In addition, Member States pursue different objectives with different priorities (for instance, regarding technologies or by focussing on low support costs versus effectiveness) and may therefore have difficulties to apply a harmonised approach.

Second, Ragwitz et al. (2007) have argued that, before the EU adopts a harmonised RES-E support scheme, it is necessary to establish a common electricity market. According to the authors, divided national electricity markets run counter to the objective of increased efficiency through harmonisation. Bergmann et al. (2008) pointed in a similar direction: for the time being, they recommended a focus on harmonising framework conditions and obliging Member States to implement best-practice generic design criteria in their national support schemes.

Third, full harmonisation (i.e. top-down coordination) would lead to a lack of policy competition and innovation, which could ultimately decrease the effectiveness and efficiency of support schemes rather than increase it. Several authors point to the dynamic and successful deployment of renewables in national support schemes, particularly regarding feed-in tariffs (Meyer 2003, Lauber 2004, Jacobson et al. 2009). Their arguments mainly opposed quota schemes based on tradable green certificates (TGCs), which is characteristic of the early phase of the harmonisation debate. For instance, Lauber (2004) argued that "using harmonisation to eliminate all but RPS [Renewable Portfolio Standards] systems is to ignore a key requirement of a rapid transition to a renewable-based system. The coexistence of state-of-the-art models of both schemes is likely to be more helpful". Jacobsson et al. (2009) stressed the innovation of national RES-E support policies that would be threatened by a harmonised scheme.

Fourth, a full harmonisation of support schemes would neglect domestic costs and benefits and could lead to local opposition and loss of public acceptance for RES-E deployment. Since harmonisation would shift renewable energy support to those regions where the operation of plants is most cost-efficient, industry, skilled workers, and investments would leave regions where renewable energy was not sufficiently profitable. As a result, some Member States would benefit while others would suffer. This could potentially lead to increased political and local resistance (Ringel, 2006). A uniform, EU-wide quota, on the other hand, would hardly be practicable in political terms (Resch et al. 2013). Del Rio (2005) argued that if policy makers give priority to the local/regional/national benefits of RES-E, "then harmonisation in combination with a tradable green certificate scheme is not so advantageous for countries." (Del Rio, 2005). Klessmann et al. (2010) have also emphasised such indirect costs and benefits, albeit with regard to the cooperation mechanisms of the Renewables Directive. They point to the fact that, besides the direct support costs, "Member States should consider the indirect costs and benefits for RES-E deployment in their cooperation. (…) The final balance, however, will be the result of a negotiation process between the involved Member States" (Klessmann et al. 2010).

Fifth, full harmonisation of support schemes is not practical against the background of the broader national energy policies and different policy interests. Energy policy has been a competence of Member States since the foundation of what is now the European Union and Member States have developed national energy policies with different goals and ambitions, also with regard to the national electricity mix. Moreover, these policies are often adapted to local natural circumstances: e.g. to the availability of natural resources such as solar irradiation, rivers, coal or natural gas. As a result, not all Member States share a comparable ambition towards renewable energy and most Member States are not yet willing to transfer these competences to the European level. This makes harmonisation of renewable energy support politically difficult to achieve (Ringel, 2006; also Lauber 2004). While other authors underlined that it could be beneficial to "move towards the definition of some common rules (…) as rapidly as practicable" (Connor/Mitchell 2004: 34), they recognised that there was a deep trench between the interests of Member States themselves and the Commission. Dissent can concern: the right instrument (feed-in tariffs vs. TGCs); the level of harmonisation (subsidiarity vs. full harmonisation); and economic fairness (benefits vs. disadvantages for Member States due to a single market).

In short, numerous arguments have been raised since the early calls for full harmonisation of support schemes, most of which are equally valid today. This is true at least if the option to harmonise was a technology-neutral quota scheme, which would not have struck a good balance between market compatibility and minimized investment risks. At the same time, numerous support scheme regulations in Europe heavily divert from best practices and persisting fragmentation of support scheme designs in Europe pose a serious barrier for the actual implementation of the internal energy market. Thus, in contrast to a full top-down harmonisation, what does bottom-up cooperation and coordination deliver in terms of increasing policy convergence towards best practices?

5.4 Bottom-up cooperation and coordination

So far, the bottom-up approach allows for decentralised cooperation in "participatory networks, experimentation, learning and persuasion" (Benz 2007). This bottom-up process, which is similar to "intergovernmental cooperation", has effectively been applied in different fora, such as the International Feed-In Cooperation (IFIC) which was founded by Germany and Spain and later on joined by Slovenia and Greece. It aims to "promote the exchange of experience concerning feed-in systems, improve feed-in systems where necessary by, e.g., increasing their efficiency and effectiveness, support other countries in their endeavours to develop and improve feed-in systems, and contribute knowledge to the international policy area, in particular to the policy debate in the European Union" (IFIC 2012). More importantly, it is worth mentioning the "Concerted Action on the

Renewable Energy Sources Directive (CA-RES)", which started in July 2010 and which is accessible to the Member States only (plus Norway and Croatia) and thus excludes the public or the academic community in order to create confidentiality. The CA-RES-E primarily serves to support the transposition and implementation of Directive 2009/28/EC on the national level, but it also serves for Member States to "exchange experiences and best practices and develop common approaches" (CA-RES-E2012).

Based on the discussed best practices, on the exchange fora and on guidance provided by the EC, support scheme design convergence does appear to be emerging. The diffusion of feed-in premium systems as a compromise between revenue security for investors and RES-E exposure to market signals seems to point towards selective and partial trends towards convergence. However, admittedly the level of detail to which support scheme regulations are effectively coordinated is rather limited, thus further steps might be required to, first, strike a better balance between market compatibility and reduced investment risks and, second, to overcome regulatory fragmentation in Europe.

5.5 Conclusions - the way forward

While in the past a combination of coordination, cooperation and selective top-down harmonisation has been applied, this approach is most likely the most feasible one for the foreseeable future as well. This mixed approach can effectively lead to increased convergence of the most important aspects of effective and efficient support schemes, which allow for gradual and selective market integration (depending on the maturity of the relevant technology and market). In this scenario, RES-E market conditions (comprised of the support scheme and other contextual conditions) would converge in the medium and long term rather than in the short term. As a result, the complete implementation of the internal market to the RES-E would also have to be envisaged in the medium and long term as a gradual process. The continuation of a mixture of top-down and bottom-up processes, also beyond 2020, would focus on harmonised minimum design criteria (top-down) and intensified coordination and cooperation between Member States (bottom-up). This option would foster policy convergence and market integration, while respecting the Member States' different preferences, which should increase the political feasibility and public acceptance of such an approach.

This mixed approach will be crucial in the upcoming development of a post 2020 framework, which is likely to either incentivise regional coordination and cooperation or even to make it obligatory. Thus, which are the main issues related to support scheme design that could be more strongly coordinated, without losing Europe's unique innovative capability?

- First, convergence will increase due to the new EEAG in terms of phasing out FITs and implementing FIPs. Further coordination (and resulting convergence) might be applied with regards to the calculation of premium payments (e.g. whether a yearly, monthly or daily electricity reference price is used).

- Second, the calculation of LCOEs is highly fragmented and could further be coordinated. This is somewhat politically sensitive as the LCOE calculation is precisely the step used by national lobby groups to influence tariff setting. At the same time, a common methodology for LCOE calculation would greatly increase comparability between the setting of strike prices.
- Third, as auctions will increasingly be implemented, an intensive exchange on possible auction designs and a structured evaluation of how different auction designs perform in different contexts seems highly recommendable. This would likely lead to the identification of best practices in auction design, which would be the basis for increased policy convergence within this specific aspect of support scheme design.
- Fourth, revising and adjusting tariffs over time is handled differently throughout Europe and, admittedly, there seems to be no "silver bullet" to strike a perfect balance between adjustments to unforeseeable cost developments on the one hand and keeping investment risks in check on the other hand. In any case adjustments should only apply to new plants and should be performed in a systematic and foreseeable manner.
- Fifth, quota obligations can be implemented as joint support schemes, but it is difficult to implement only selected joint elements. Problems with quota obligations and their recent substitution through other policies indicate that these are at the moment rather unsuitable for coordination.
- Sixth, with respect to burden sharing, rules to determine industries that should be released from some of the burden arising from RES-E-support, could be coordinated and perhaps even harmonised between MS.

Such coordination is not identical to a full top-down harmonisation. However, if implemented more effectively, coordination would lead to increased policy convergence, thereby paving the way for a more effective implementation of the internal energy market, while strengthening a good balance between market compatibility and reduction of (or keeping in check) investment risks.

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