

Regulatory instruments to deliver the full potential of renewable energy sources efficiently¹

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¹ To some extent this paper expresses viewpoints by the authors which cannot be easily proven or verified.

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Abstract

Increasing the share of renewable energy sources for electricity generation (RES-E) has a high priority in the energy strategies of the European Commission. Yet, from a pure monetary point-of-view most RES-E technologies are currently not cost-effective. Hence, if RES-E are considered to provide significant benefits for society regulatory interferences are justified. This paper analyses which regulatory issues are of major relevance with respect to the promotion and the grid integration of RES-E. Of core relevance are currently two major issues: implementation of proper regulatory financial support systems and implementation of a clear regulatory framework for cost allocation policies to integrate RES-E technically into electricity grids. The major conclusions of this analysis are: (i) with respect to the design of regulatory promotional strategies currently a well-designed (dynamic) feed-in tariff system ensures the fastest deployment of RES-E power plants at the lowest cost for electricity customers; (ii) with respect to grid integration of RES-E a (super-)shallow RES-E integration approach is clearly preferable to deep integration.

1. Introduction

Increasing the share of renewable energy sources for electricity generation (RES-E) has a high priority in the energy strategies of the European Commission. The major reason is that from society's point-of-view RES-E are considered to have the potential to contribute significantly to the solution of problems like global warming and fossil fuel supply security. Yet, so far virtually no RES-E plant has been constructed without regulatory interventions. This is because of the following two major reasons: (i) on the supply-side from a pure monetary point-of-view most RES-E technologies are currently not cost-effective; (ii) on the demand-side approaches to exhaust electricity customers Willingness-to-pay (WTP) for marketing RES-E on a voluntary base – Green Pricing models, Green power companies – have clearly failed with respect to triggering significant new investments in RES-E capacities. Moreover, it has to be stated that also in the past – under former strongly regulated market conditions – virtually no power plant has under unbiased market conditions. On the one hand, very capital-intensive plant types like hydro and nuclear have virtually always been constructed with significant public support under risk free and very favourable financing conditions (low interest rates, high depreciation times). On the other hand, fuel cost intensive plants based on coal have benefited from subsidies on coal, e.g. in Germany and the UK.

Hence, if RES-E are considered to provide significant benefits for society – see e.g. the arguments in Haas et al (2008) or Meyer (2003) – regulatory interferences are justified. In general to facilitate a breakthrough for RES-E, several economic, institutional, political, legislative, social and environmental barriers have to be overcome. Of core relevance are currently two major issues:

- implementation of proper regulatory financial support systems: In this context the most controversial and discussed issue is whether trading-based instruments (like e.g. guarantee-of-origin trade, tradable green certificates or renewable portfolio standards, or price-driven instruments (like feed-in tariffs or investment support systems) provide the better solution for society; see also e.g. Haas et al (2008), Held et al (2006).

- implementation of a sound regulatory framework (going also in line with basic unbundling and market principles) for cost allocation policies to integrate RES-E technically into electricity grids. At present these policies are very heterogeneous among different EU Member States, still violating basic unbundling and market principles: (i) The connection boundary between the RES-E power plant and the grid infrastructure has not been clarified yet; there exist the following different approaches: deep, shallow and super-shallow integration, (ii) in many EU Member States there don't exist corresponding market places for system balancing and operation to manage the variability and intermittency risk of RES-E (mainly wind) generation do not exist.

The core objective of this paper is to discuss these two categories of regulatory issues and to identify the most important features to be implemented to finally bring about the best solution for society. That is to say the basic evaluation criteria applied in the following is to minimize the overall additional costs to be paid by final customers when deploying a certain amount of RES-E¹.

2. A survey on regulatory promotion schemes

This chapter provides a survey and systematic classification of the existing types of regulatory promotion instruments. Table 1 provides an overview on regulatory promotion strategies (Menanteau et al 2004, Haas et al 2004). It is important to note that all of these regulatory instruments require governmental interferences and finally create artificial markets.

¹ Of course, this argument must be seen in relation to the current situation. One could also argue that raising the cost of electricity would be a goal in its own right, since externalities are not included in electricity prices, and higher prices reduce consumption and hence mitigate environmental problems associated with electricity generation. Yet, as long as no such tax exists, an accepted subsidy in form of a FIT or a green certificate can to some extent help to solve the problem.

Table 1. Survey on regulatory promotional strategies for supporting RES-E (Menanteau et al 2004, Haas et al 2004)

		Direct		Indirect
		Price-driven	Quantity-driven	
Regulatory	Investment focused	<ul style="list-style-type: none"> • Investment subsidies • Tax credits • Low interest/Soft loans 	<ul style="list-style-type: none"> • Tendering system for investment grant 	<ul style="list-style-type: none"> • Environmental taxes • Simplification of authorisation procedures • Connection charges, balancing costs
	Generation based	<ul style="list-style-type: none"> • (Fixed) Feed-in tariffs • Fixed Premium system 	<ul style="list-style-type: none"> • Tendering system for long term contracts • Tradable Green Certificate system 	

Fundamentally, there are two basic regulatory ways to subsidize or promote RES-E: price-driven and quantity-driven strategies.

2.1. Regulatory price-driven strategies

Under these schemes no quantity goals or targets are established. Instead, the focus is on providing generators with financial support in terms of a subsidy per kW of capacity installed or a payment per kWh of energy produced. There are a number of variations under this scheme such as:

- Investment focused strategies where financial support is provided through investment subsidies, soft loans or tax credits, usually per unit of generating capacity installed;
- Generation based strategies where financial support is offered as a *fixed* payment or as a *premium* per unit of energy generated.

Under a fixed payment scheme such as feed-in-tariffs (FITs), generators receive a fixed amount per kWh generated regardless of the costs of generation or price while under a premium scheme a fixed amount is added to the electricity price. In practice, this makes a big difference for the renewable plant owner. In the latter case, the total price received per kWh (electricity price plus the premium) is less predictable than under the FIT because it depends on a volatile electricity price.

2.2. Regulatory capacity-driven strategies

Under these schemes, the policy makers set a desired quota or goal, usually with a target date, to encourage the market penetration of RES. Examples include:

- Tendering or bidding schemes which call for tenders to acquire specific amounts of capacity or generation from specified types of RES. Competition between bidders leads to the winners of contracts which will receive a guaranteed tariff for a specified period of time

- Tradable certificate schemes such as renewable portfolio standards, which are popular in the US, or tradable green certificates (TGC) in Europe. These schemes typically obligate one or more parties involved in the electricity supply chain such as the generators, wholesalers, distribution companies, or retailers to acquire a certain percentage of electricity from RES in their energy mix. Most schemes allow parties to trade certificates to demonstrate compliance. Certificates may be obtained in three ways:
 - from their own renewable electricity generation;
 - by purchasing renewable electricity and associated certificates from other generators; and
 - by purchasing certificates without purchasing the actual power from a generator or broker.

2.3. How feed-in tariffs and trading systems work

Based on the concept of static (and further-on dynamic) cost resource curves of RES (see e.g. Resch et al 2004) TGC-based quotas work as follows (see Fig. 1 – right panel): A quantity/quota (=certain percentage of electricity to be guaranteed from renewable energy sources) is set by a government. The generators (producers), wholesalers, retailer or consumers (depending who is obliged in the electricity supply chain) have to supply/consume a certain percentage of electricity from renewable energy sources. At the date of settlement, they have to submit the required number of certificates to demonstrate compliance.

A Feed-in tariff (FIT) works as follows: a guaranteed price per unit of electricity is paid to a RES-E generator, if his form of generation meets certain criteria. Thus, a federal (or provincial) government regulates the tariff rate. The output due to FITs is uncertain due to the uncertainties in the cost curve (Fig. 1 – left panel). The FIT attracts new capacity, as long as the unit price is sufficiently high (see e.g. the substantial growth of wind power in Denmark, Germany and Spain in recent years).

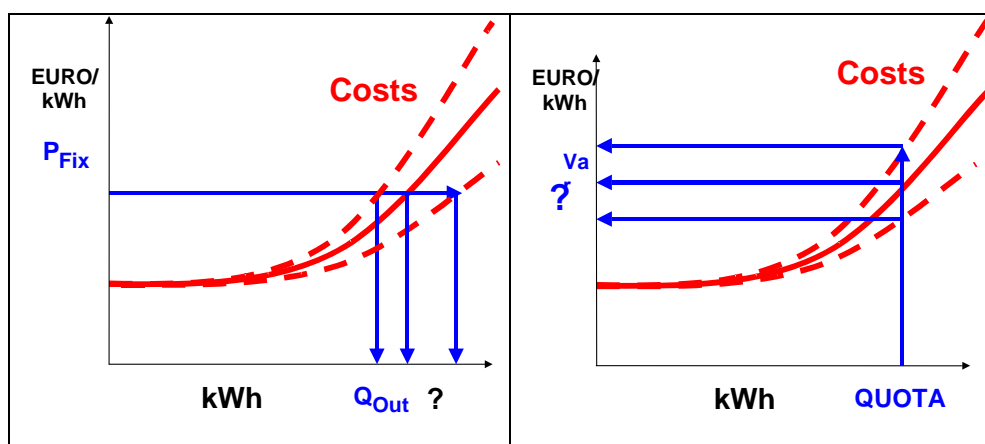


Figure 1. How feed-in tariffs (left) and trading systems (right) work in principle (Source: Haas et al 2004)

3. Criteria for effective promotion schemes and lessons learned

As has been stated before with respect to generating electricity from new RES the following ambiguous situation exists:

- on the one hand past experience has shown that there is no sufficient voluntary WTP from most electricity customers to trigger significant investments in new plants;
- on the other hand there are expected benefits for society from a significant increase in RES-E generation.

This ambiguous situation is the reason for the introduction of regulatory strategies. Given this pre-condition regulatory promotion schemes must focus on two core criteria: (i) a significant additional amount of new capacities installed and (ii) the support costs for these new plants should be as low as possible.

With respect to minimizing support costs the following reflections are important: all types of regulatory strategies create artificial markets and cause additional costs for final electricity customers. One of the major criteria for a successful promotion system is the acceptance by the final electricity customers (who finally in every promotion system will pay the costs). This acceptance is of course strongly dependent on the magnitude of over-all support – the transfer costs which have to be paid by final customers. So it is firstly important to analyze the additional costs of a specific programme for the electricity consumers. Fig. 2 depicts the cost definitions and various cost elements to be considered. The additional costs are calculated as:

Additional costs for consumers = Producer Surplus + Generation costs - Revenues electricity market

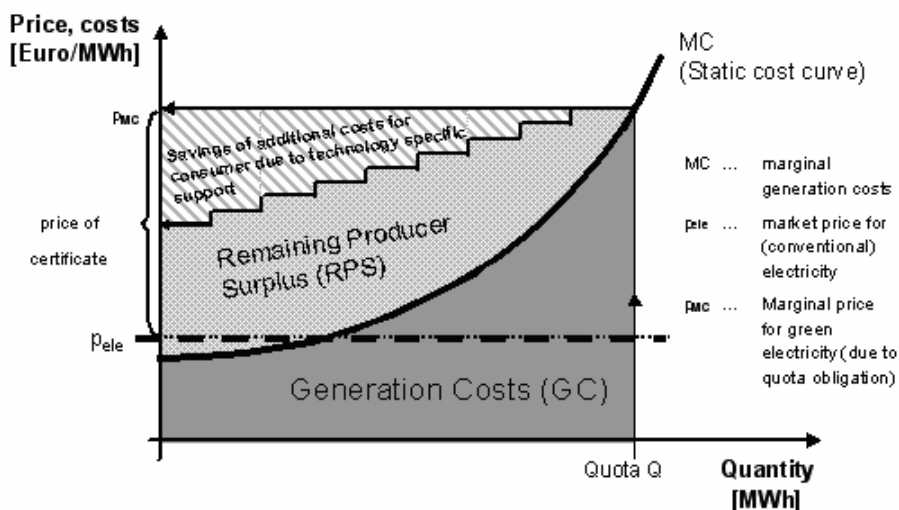


Figure 2. *Minimizing extra costs for final customers (Source: Haas et al 2004, Held et al 2006)*

From society's point-of-view it is important to minimise these additional costs (fees finally paid by households, commercial and industrial electricity customers) for the following reasons: the lower these additional costs are, the greater is the public acceptance and the larger will be the amount of additional electricity generated from RES per unit of public money.

So the most effective strategy must focus finally on the minimization of total transfer costs to ensure both, acceptance by customers and by investors. To minimise producer surplus (PS)², a stepped promotion scheme that limits PS should be introduced, see Fig. 2. RPS in Fig. 2 is the remaining producer surplus, defined as the producer surplus after a stepwise support scheme has been enacted.

Another important aspect is the shape of the cost curve. Fig. 3 and Fig. 4 depict two different types. While in Fig. 4 the PS is small due to a rather flat cost curve in Fig. 3 the opposite applies. A steep cost curve leads to a PS significantly higher than the overall cost. So while in Fig. 3 there might be only a small difference in the extra costs customers will pay for RES-E in a trading system compared to FIT's this difference will be remarkably higher in Fig. 7.

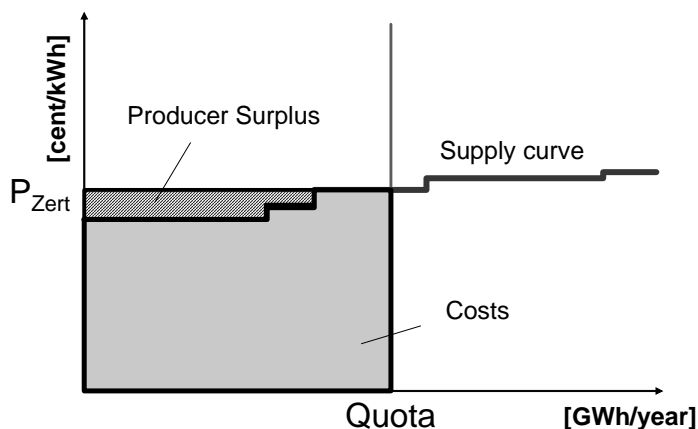


Figure 3. Impact of the shape of the cost curve on producers' surplus

² The producer surplus is defined as the profit of all green electricity generators. Example: if a green producer receives a feed-in tariff of 6 €cent/kWh and his generation costs are 4 €cent/kWh, the resulting profit would be 2 €cent per kWh. The sum of the profits of all green generators defines the producer surplus.

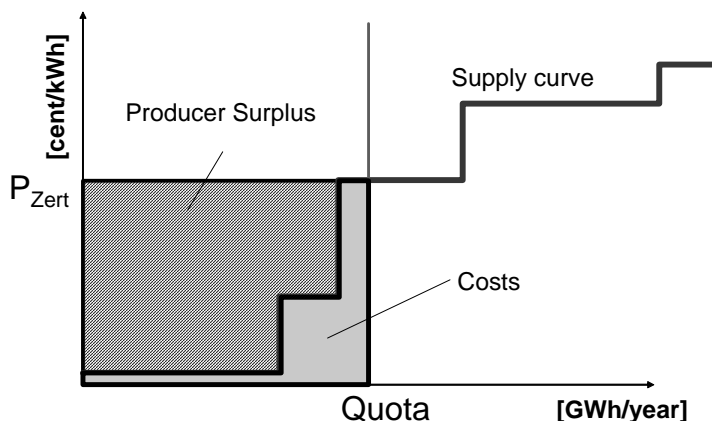


Figure 4. Impact of the shape of the cost curve on producers' surplus

3.1. Performance of tradable green certificate systems vs feed-in tariffs

The most lively discussion regarding the preferable promotion scheme is currently being held throughout the EU on the advantages and disadvantages of feed-in tariffs on the one hand and quota obligation systems based on TGCs on the other hand. In this chapter next the relation between quantities deployed and the level of support of TGC vs FIT systems is analysed for the most important countries in recent years. For assessing effectiveness the indicator “kWh generated from new capacities per capita and per year” is used. It can be seen that the best performance – highest effectiveness and lowest support level – is provided by the three FIT-countries in the sample – Austria, Germany and Spain – and by Sweden relying on a TGC system. On the other hand, TGC-countries like Italy, Belgium³ and UK are among those with the highest support levels and lowest specific deployment (Figure 5).

³ Note that Belgium officially has a TGC system, but the grid operators are obliged to buy the certificates for a minimum price. Hence, this system also includes components of a FIT.

In countries with strong feed-in tariff systems like Germany and Spain, many stakeholders expressed a clear preference for the present system, indicating appropriate tariffs, long-term stability and transparency as its major highlights. Other voices from the same countries, however, suggested replacing the feed-in system with what they consider to be a more market-based instrument, proposing the introduction of a quota obligation system. The main perception from these stakeholders was that this system is more cost efficient for promoting high penetration of renewable energy (see Ragwitz et al, (2007)).

In general one can conclude that the majority of the stakeholders acknowledge that a long-term framework is a prerequisite for the cost-efficient promotion of electricity generation from renewable energy sources. Market-based instruments like quota obligations with TGC only seem able to stimulate the market development of already mature technologies. How the maturity of the market and of the respective renewable energy technology is perceived depends strongly on the individual and his/her role in the renewable electricity community.

As far as the quota obligation system is concerned, it was pointed out that technology specification should be incorporated into the existing systems, e.g. in the UK, in order to open up opportunities for immature technologies like wave and tidal electricity generation. Another issue was that penalties must be enforced if the obligation is not fulfilled to make the system work. It was suggested that penalties be set for a longer period of time, thus creating more transparency for the market regarding the financial consequences of not fulfilling the obligation. Sharing out the buy-out fund among suppliers who fulfilled the obligation, as carried out in the UK, is an interesting way of stimulating electricity suppliers to meet the obligation.

Summing up: it is often argued that the reason for higher capacities installed is a higher support level. High FITs especially in Germany and Spain are often named as the main driver for investments especially in wind energy. However, the support level in these countries is not particularly high compared with other countries analysed here. Paradoxically, from Fig. 5 – with the exception of Sweden – the opposite can be seen.

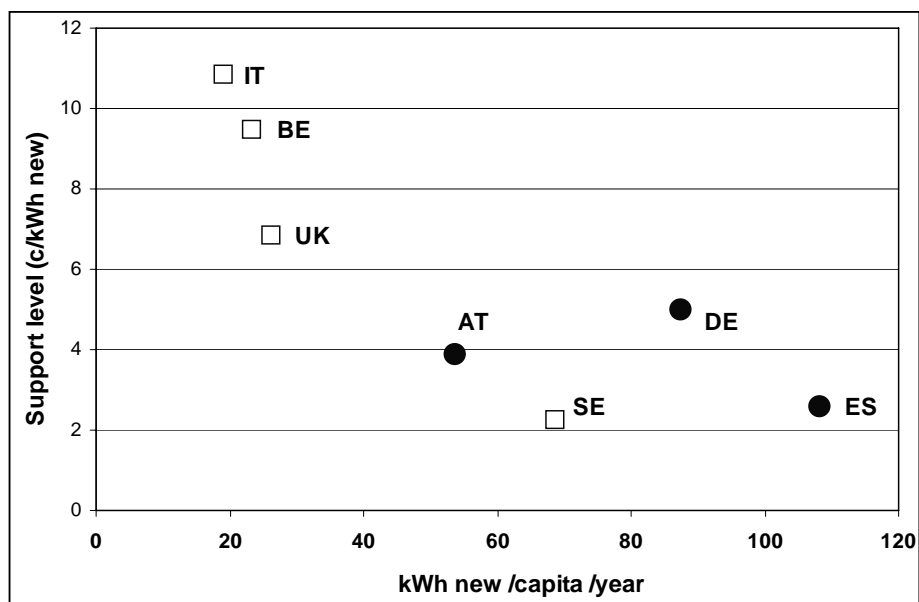


Figure 5. Effectiveness vs costs of electricity from RES in TGC vs FIT programmes in selected European countries (Average 2002-2006) (Source: own investigations)

In the following the criteria to implement trading systems and FIT effectively are described.

3.2. Criteria for effective tradable green certificate systems

Due to competition on the supply side tradable certificates systems lead, under the assumption of perfect market conditions (perfect price signal), to minimal generation costs for RES-E. Of course, this happens only if there is a surplus of RES-E generation above the demand for certificates.

The major theoretical arguments in favour of TGC are:

- high economic efficiency;
- a market for best-practice in the environment is created;
- no market distortion due to fixed subsidies;
- the market determines the magnitude of the subsidy.

Possible drawbacks are:

- unpredictable (volatile) revenues for generators;
- risk premium is included in the cost curve
- uncertainty about actual investment;

The most important conclusions with respect to the correct design of quota-based trading systems are:

(1) High penalty for not purchasing a certificate:

It has to be guaranteed more or less by fundamental/reasonable-law that the penalty for not purchasing a certificate is significantly higher than the expected market price for TGCs. Otherwise, no incentive to fulfil the quota exists.

(2) Focus on new capacities:

The aspect of high producer surplus might be worsened if existing or already cost-effective capacities are included, see Fig. 6. This Figure depicts that including capacities which would have been constructed without the promotion scheme tremendously deteriorates the performance of the promotion scheme.

Hence, if a quota-based trading system is introduced it has to focus mainly on newly installed plants which are currently not yet cost-effective. If a large share of the required capacity to meet a quota already exists, trading systems lead to windfall profits for the owners of existing plants, see Fig. 6. Hence, it is counter-productive to include old depreciated facilities into a trading system especially if the marginal cost of new capacity is high.

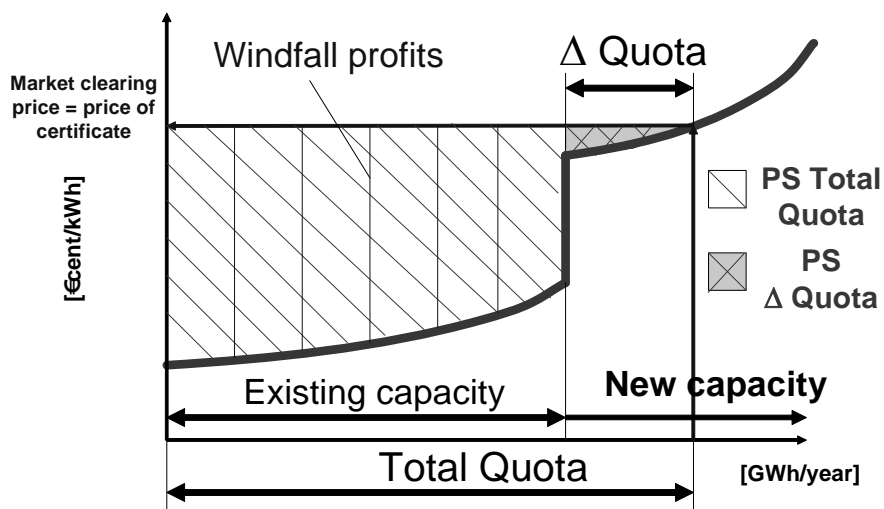


Figure 6. Comparison of producer surplus and windfall profits if existing capacity is included in a quota or not

3.3. Criteria for effective feed-in tariffs

Feed-in tariffs (FITs) have attracted attention since the late 1980s especially in Denmark, Germany, Italy and, in the 1990s, in Spain. Currently, FITs in Europe are in force in most EU countries, the most successful ones in Germany and Spain, see Haas (2008).

The major perceptions with respect to feed-in tariffs are:

- Feed-in tariffs have been successful for triggering substantial new RES-E capacities in almost all countries where they have been introduced;
- The major advantage of a feed-in tariff is that it is effective, flexible, fast and easy to install (and to revise or to abandon if there are difficulties);
- The major criticism of feed-in tariffs is that they do not encourage competition between generators. However, competition is not, in itself, a policy objective. The objectives relate to the dissemination and enlargement of RES-E in a beneficial and acceptable manner. Therefore

as long as a policy instrument contributes to such societal goals, it should be forced to conform to conventional practice. Of course, if an optimal solution for society can also be obtained by applying another means, then this means is also justified. There need not be one single solution.

- Feed-in tariffs are an efficient and effective dissemination instrument, if:
(i) the feed-in tariff decreases over time, as experience is gained and in line with the expected learning curve; (ii) a stepped and technology-specific feed-in tariff is used.

One important condition for such a scheme is the measurable and standardised unit or baseline used for differentiation. If the costs for electricity generation are mainly based on the full-load hours, the latter can be such a suitable baseline. In this case, there is less dependence on specific, not standardised, criteria such as fuel costs or the special conditions of the location. Unfortunately, not every renewable energy technology fulfils this constraint. For wind energy or biogas this criterion is fulfilled, i.e. a stepped feed-in tariff is easy to implement. In the case of biomass, where costs depends on the specific fuel input (bark or wood chips from forest residues) an evaluation of the fuel mix must be made. This causes an increase of the administration costs and results in a less efficient system. However, in principle, an incentive compatible scheme is implementable.⁴

4. The grid connection/access boundary question

The second major category of regulatory issues is the integration of significant amounts of DG/RES-E generation technologies into the existing electric grid. In this context the grid connection/access boundary question is still one of the most controversial issues in practice. Moreover, besides the connection of DG/RES-E facilities to the existing grid infrastructure also grid reinforcement and extension measures caused by large-scale DG/RES-E system integration raise a set of new questions, e.g. where to allocate the corresponding extra cost and how to socialize them. In any case, in a meshed grid infrastructure the allocation of grid reinforcement and

⁴ In this case, different feed-in tariffs exist in parallel, depending on the fuel input.

extension measures and corresponding cost to a newly integrated DG/RES-E generation facility is ambiguous, see Figure 7.⁵

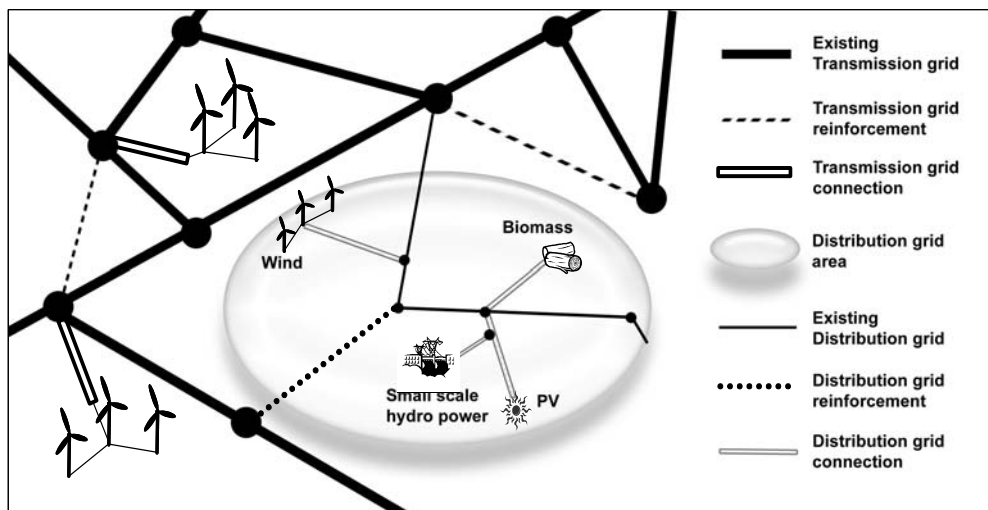


Figure 7. Grid connections and grid reinforcements caused by large-scale DG/RES-E integration. Source: Auer (2006).

The core problem in this context is that any changes in a meshed grid infrastructure (e.g. also disconnection of a large industrial customer) will change the load flows in an electricity system. Therefore, the status quo of load flows in an electricity system is also just a snapshot of the existing randomization of generation and load centers. Moreover, the status quo as well as changes of load flows bear a variety of dimensions, as there are e.g. changes in the geographic distribution of generation and load centers, bottlenecks in peaking periods or commercial power trading activities. Therefore, the allocation of load flow changes and, subsequently, grid reinforcement and extension measures to the integration of a single new DG/RES-E generation facility is at least questionable.

⁵ Not least due to the fact that several other market participants (especially power traders, but also end-users due to increased security of supply) also benefit in their business segments from additional transmission capacities.

4.1. Different grid connection boundaries for DG/RES-E generation facilities

Textbooks in economic theory would expect to allocate both DG/RES-E grid connection cost and grid reinforcement and extension cost to the grid infrastructure and to socialize these costs through the transmission and distribution tariffs⁶ (and not to include either of these two cost components to the total DG/RES-E project cost). In practice, however, several grid-related cost components (at least the grid connection cost) are still allocated to the long-run marginal generation cost of the DG/RES-E power plant, especially as far as DG/RES-E grid connections to the distribution grid are concerned. In general, the following grid connection boundaries between the DG/RES-E generation facilities and the grid infrastructure are possible (see Figures 8, 9a and 9b):

- **“Deep” Integration:** Based on this approach, the DG/RES-E developer bears several extra grid-infrastructure related DG/RES-E integration cost (i.e. grid connection as well as grid reinforcement/extension cost) and includes them into the total DG/RES-E project cost.
- **“Shallow” Integration:** The shallow grid integration approach usually characterises the situation where the DG/RES-E developer bears the grid connection cost, but not the grid reinforcement/extension cost (they are socialised in the grid tariffs).
- **“Super-Shallow” Integration:** This is supposed to be the most convenient approach for the DG/RES-E developers since neither the grid connection cost nor the grid reinforcement/ extension cost are borne by them.

⁶ In principle, there exist both options: (i) socialisation within a supply area of a grid operator or (ii) socialisation across the whole country (i.e. covering also several other grid operators).

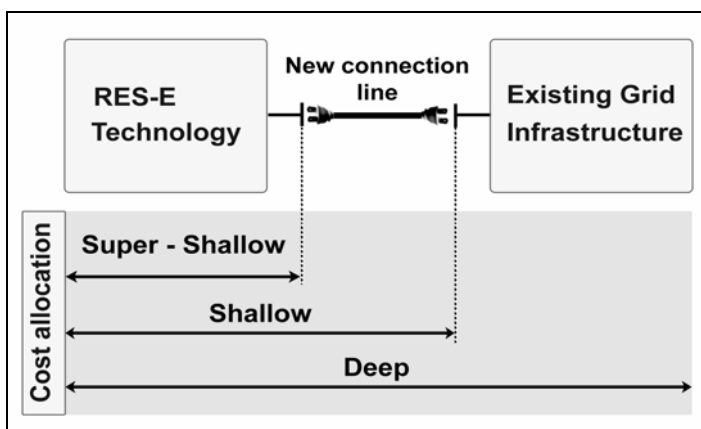


Figure 8. *Different connection boundaries between the DG/RES-E power plant and grid infrastructure*

In practice, however, there mainly exist hybrid approaches incorporating elements of both “deep” and “shallow” DG/RES-E grid integration. This means in particular that usually parts of the grid reinforcement and grid extension cost are usually allocated to the newly connected DG/RES-E generation facility (i.e. some kind of “deep” grid integration free) and remaining parts of the deep cost are socialized in the grid tariffs. In addition, the entire grid connection costs are borne by the DG/RES-E developer and allocated to the long-run marginal generation cost in the hybrid model. Table 2 summarizes the status quo of the implemented cost allocation policies for DG/RES-E grid integration in the ‘old’ EU15 Member States in 2007.

The existing pattern for allocating the DG/RES-E grid integration cost might change in the near future in various EU Member States. This is caused mainly by the currently ongoing benchmarking and grid regulation exercises being conducted by national regulators. Primarily these activities are driven by the pressure of the European Commission (EC) to fulfill the basic unbundling principles of the different EU-Directives and the implementation of cost transparency in grid infrastructure charging. Yet these efforts will also affect DG/RES-E grid integration policies. Finally, the existing boundaries between the DG/RES-E power plant and the grid infrastructure may be shifted increasingly towards the DG/RES-E

generation facilities, resulting at least in a “shallow” integration policy or even beyond.⁷

Table 2. DG/RES-E grid integration and cost allocation policy in the ‘old’ EU15 Member States in 2007 (adapted from Auer (2006)).

	RES-E grid integration cost allocation scheme	Max. grid connection cost	Cost transparency
Austria	Deep	10% of investment	Low
Belgium	Hybrid	5-10% of investment	High
Denmark	Shallow	5-10% of investment	High
Finland	No standardised approach	-	Medium
France	Hybrid	10-20% of investment	Medium
Germany	Hybrid	-	Low
Greece	Hybrid	-	Low
Ireland	Deep	3-8% of investment	High
Italy	Deep	-	Low
Luxembourg	Deep	-	Low
Netherlands	Hybrid	-	High
Portugal	Deep	15% of investment	Medium
Spain	Deep	-	Low
Sweden	Deep	10% of investment	Low
UK	Hybrid	8-12% of investment	High

The “super-shallow” DG/RES-E grid integration policy finally fulfils almost all expectations of the theoretical considerations in economic theory. However, the locational signal aspect may get increasingly lost in case of this DG/RES-E grid integration policy. But this is an important dimension for a sustainable and cost minimizing integration of DG/RES-E generation facilities into existing electricity systems, especially as far as small generation units into distribution grids are addressed.

Therefore, the “super-shallow” grid integration policy option has been developed in recent years mainly for large-scale offshore-wind (but also onshore-wind) integration into the existing transmission grids rather than for integration of remaining DG/RES-E generation technologies on

⁷ Interestingly, in the past the demand site always has been treated differently (compared to the generation site) when defining the grid connection boundary of customers. According to economic theory there is no obvious reason to do so (see e.g. Jamasb et al (2005)). Demand customers traditionally have paid “shallow” connection charges – for assets specifically required for their connection – whilst distributed generators have been charged on a “deep” basis, i.e. the full cost of work arising from the connection including the costs of replacing equipment associated with protecting the network or also the provision of ancillary services. However, an increase in DG/RES-E grid integration in the future, especially at connections which may export and import electricity at different times, is expected to blur the established distinction between demand and generation connections thus fundamentally changing distribution grid operator’s cost drivers. These new circumstances also lead to the conclusion that existing charging structures for DG/RES-E grid integration (still mainly “deep” and “hybrid” models; see Table 2) may no longer be appropriate.

distribution grid level. Moreover, when considering large-scale offshore wind integration into transmission grids, usually the economic situation presented in equation (1) exists. If $C_{Transmission,i}$ are the offshore transmission grid connection cost of an individual wind farm i in case of separate grid connection (see Figure 9a (left)) and $C_{Transmission,common}$ the common offshore transmission grid connection cost of all wind farms (c_i is the individual short distribution grid component of wind farm i ; see Figure 9b (right)) the following relationship exists:

$$C_{Transmission,common} + \sum_{i=1}^n c_i < \sum_{i=1}^n C_{Transmission,i} \quad (1)$$

Equation (1) demonstrates that aggregated transmission grid connection cost of the individual offshore wind farms (Figure 9a (left)) are higher than the common transmission grid connection cost (plus individual short distribution grid components) of a collective of several offshore wind farms (Figure 9b (right)).

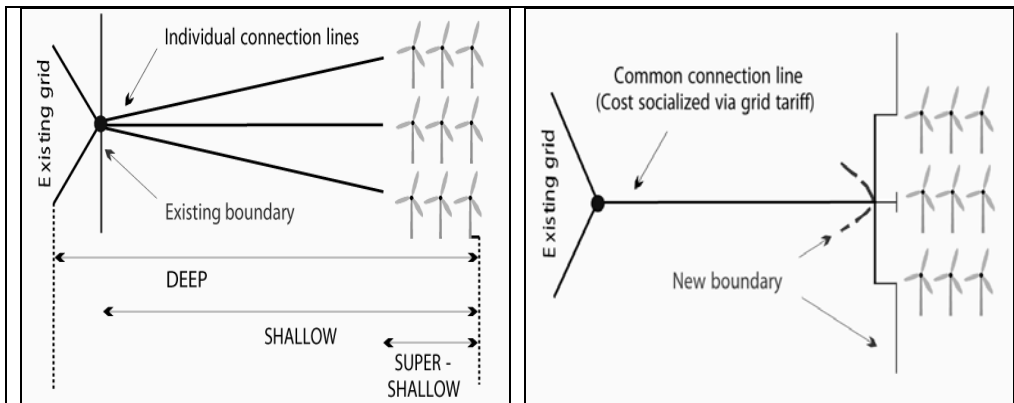


Figure 9a. *Separate offshore grid connection of each individual offshore wind farm and indication of different boundaries for different integration policies. Source: Auer (2006).*

Figure 9b. *Common offshore grid connection of several offshore wind farms and shift of new connection boundaries towards offshore wind farms. Source: Auer (2006).*

4.2. The locational signal aspect

The overall objective of different cost allocation and DG/RES-E integration charging policies is to guide efficient expansion and use of the electricity grids (distribution grids in particular), on the one hand, and efficient management of the assets connected to the grid infrastructure representing both generation and load facilities, on the other hand. Whereas economic theory presents clear approaches and procedures for optimal DG/RES-E grid integration into existing electricity systems,⁸ circumstances in practice are far more complex and accompanied by a variety of uncertainties, imperfections and problems. A selection of these critical issues of the different DG/RES-E integration policies in practice is discussed below.

4.2.1. “Deep” integration: ideal versus real world

In general, the deep DG/RES-E integration approach has the advantage of providing strong locational signals for new entrants. However, this approach – having been traditionally adopted by distribution grid operators in the past – is far from uncritical. In practise there exist at least the following vexing challenges (see also Jamasb et al (2005), DTI (2006), Auer (2006), Auer (2007), Vogel (2008), Barth et al (2008)):

- Although deep DG/RES-E integration is characterised by favourable locational signals to new entrants, the computation of proper deep connection cost (and, subsequently, connection charges to DG/RES-E generators) is very difficult because it is impossible to correctly foresee the future set of entrants on the distribution grid, their needs (e.g. connection capacity) and the values they place on each location.⁹ Therefore, a best guess has to be made when calculating location-specific deep connection charges, trading-off the benefits of larger increments against the risk of over-sizing connection capacity and hence

⁸ In economic theory, the general principle underlying efficient DG/RES-E grid integration charging is that charges should reflect the different marginal cost and benefits to the electricity system at each node of DG/RES-E connection.

⁹ Only in theory the distribution grid operator can optimally plan the distribution network and specify the location of each new entrant by setting corresponding location-specific and entrant-specific deep connection charges. In this ideal world the total collected connection charges from each entrant at each location would exactly add up to the total connection cost of several new DG/RES-E generators on distribution grid level.

prescribing overcharges for connection of DG/RES-E generators.

- Furthermore, assuming the case that the connection assets of a specific location are shared by more than one DG/RES-E generator, the cost would also be shared, but as the assets would be quasi-public goods, efficient charges would not necessarily be the same for several new entrants at the same location if their willingness to pay is different.
- In almost all cases the situation described above is getting even more complex, since DG/RES-E connection inquiries are rather sequential in time than simultaneous. For sequential connection inquiries the first mover problem at a specific location is inherent, i.e. the critical question arises whether or not the first entrant shall be charged the full cost and encourage subsequent entrants to rebate some fraction (either by granting the right to the first entrant to charge successors, or calculating a charge for successors by the distribution grid operator and rebating it to the first entrant).¹⁰
- Last but not least, there exists a strong concern about the deterrent effects on large-scale DG/RES-E deployment in case of deep integration charging policies. Moreover, this approach completely violates the basic unbundling principle and, therefore, also undermines the legal framework of the EC-Directives of the European Commission trying to implement a common internal European electricity market.

4.2.2. “Shallow” integration: ideal versus real world

Although deep DG/RES-E integration policies provide strong locational signals, recognition of the disadvantages of this approach has favoured rather hybrid mechanism (incorporating elements of both deep and shallow charging) in majority of EU Member States in recent years (see Table 2 in detail). Moreover, not least driven by the expectations to fulfil the basic

¹⁰ In general, DG/RES-E generators and, therefore, also the first entrant are likely to be less well-informed than the distribution grid operator about the connection capacity needed and corresponding cost. Moreover, the first entrant usually is also not in a financial position to raise the capital to pay for more than its own grid connection. Therefore, from the first mover’s point-of-view it is an advantage if distribution grid operators charge for the cost of the connection in proportion to the use made of the different entrants. However, in this ideal case the distribution grid operator faces the following risks: (i) subsequent entrants must arrive as predicted, (ii) the correct connection capacities must be chosen and (iii) the willingness to pay for connection of subsequent entrants must be similar.

unbundling principles of the EC-Directives further amendments towards shallow integration policies are expected in the context of DG/RES-E grid integration in the near future.

Shallow DG/RES-E integration policies aim to limit the connection assets attributed to the entrant (e.g. up to the next voltage level). However, if it is to signal location for DG/RES-E integration into the existing distribution grid efficiently, then a shallow integration charge has to incorporate also location specific cost elements. Otherwise there will be a tension between the entrant wishing to connect to the nearest point of the distribution grid from his most favourable location, on the one hand, and the distribution grid operator favouring connection at points which minimise total network cost, on the other hand. This could lead the distribution grid operator delaying or otherwise obstructing entry at some points on the distribution grid if it is not clear which points were in fact cost-minimising. The ultimate peculiarity of a locational signal in the shallow integration approach therefore is a rejection of a DG/RES-E connection inquiry.

4.2.3. “Super-Shallow” integration: ideal versus real world

As already mentioned in section 4.1, the locational signal aspect is getting increasingly lost in case of the “super-shallow” grid integration policy. Although the locational signal aspect is important for cost minimizing integration of DG/RES-E generation facilities into existing electricity systems (especially for small generation units into distribution grids), this aspect is less relevant in case of large-scale onshore- and offshore-wind integration on transmission grid level. Moreover, large-scale utilisation and grid integration of the best wind sites (both onshore and offshore) rather is a planning issue (i.e. the grid infrastructure is planned and built to those sites with the best wind conditions (quantified by parameters like wind speeds, full load hours, etc.)) than a free choice of location of wind developers. Therefore, in this case the locational signal aspect is far less important than for small DG/RES-E generation facility integration on distribution grid level.

Compared to the deep integration approach, shallow and super-shallow integration charging has at least the following further advantages (see also Jamasb et al (2005), DTI (2006), Auer (2006), Vogel (2008), Barth et al (2008)):

- Shallow and super-shallow DG/RES-E integration cost and corresponding charges are presumably easier to define than those for the deep integration approach.
- In the shallow and super-shallow integration approach the first mover problem disappears since the first entrant is expected to be charged only for the cost of the connection in proportion to the use made of it. Moreover, from the grid operator's point-of-view the risk of cost remuneration in case of over-sizing connection capacity (e.g. for providing the basis for synergies for later DG/RES-E connections at the same location) disappears since grid reinforcement and upgrading cost are socialised in the grid tariffs and, therefore, are directly borne by the network users.
- Previous arguments lead to the conclusion that barriers for entry are low in case of shallow integration policies, providing favourable framework conditions for large-scale DG/RES-E deployment on distribution grid level. Moreover, shallow DG/RES-E integration is supposed to be more transparent and acceptable for several parties involved.
- In general, total DG/RES-E integration costs are lower in case of shallow and super-shallow integration policies. This is due to the fact that financing cost is likely to be higher for DG/RES-E developers than for regulated grid operators.¹¹ Moreover, cost components for grid reinforcements and upgrades – being allocated to the distribution grid operator and socialised in the grid tariffs of the network users in case of shallow integration – are not included into the financing cost of the DG/RES-E developer to be connected (where a higher risk premium would be incorporated compared to the socialisation in the grid tariffs). This provides a strong argument against deep integration charging.
- Finally, the shallow DG/RES-E integration approach goes even more in line with the basic unbundling principles of the EC-Directives than the deep approach. Moreover, due to clear separation of the assets of DG/RES-E generation facilities, on the one hand, and the grid

¹¹ Mainly due to higher risk premiums and shorter depreciation periods the financing cost are likely to be higher for DG/RES-E developers than for regulated distribution grid operators. For example, DG/RES-E generation facilities are depreciated in time horizons of 10-15 years whereas regulated grid operators depreciate their grid infrastructure assets in 40-50 years.

infrastructure, on the other hand, extra grid infrastructure cost (grid reinforcements, upgrades and extensions) caused by large-scale DG/RES-E integration can even better be incorporated directly into “forward-looking” grid regulation models where an extra term can be foreseen to socialize this kind of extra costs.

5. The problem of asset stranding for distribution grid operators

5.1. Cost drivers for grid operators

The previous section has comprehensively analyzed the different cost allocation and DG/RES-E grid integration policies mainly from the DG/RES-E developer’s point-of-view. However, when considering large-scale DG/RES-E integration also the distribution grid operator is confronted with much more financial risk as stated up to now:

- On the one hand, currently implemented grid regulation models (like price-caps, revenue-caps, etc.) apply a strong downward pressure on the distribution grid operator’s cost and, subsequently, also distribution grid tariffs. At present, this regulatory environment adversely affects any investment initiatives into the electricity grid infrastructure, not only those foreseen to provide a level playing field for large-scale DG/RES-E integration and other innovations like so-called “smart grid” concepts;
- On the other hand, electricity grids are capital-intensive infrastructure elements being characterized by grid assets’ life-times over many decades. Therefore, long-term investments into the grid infrastructure expect stable regulatory conditions. Moreover, once investments are made they are effectively sunk and, therefore, grid assets are vulnerable to changes in regulatory conditions which could prevent or hinder cost recovery. Therefore, distribution grid operators are extremely reluctant to enable large-scale integration of DG/RES-E generation facilities into their distribution grids, unless the corresponding extra cost drivers in this context are not understood, quantified and – most importantly – cost recovery is guaranteed based on innovative, forward-looking grid regulation models.

Figure 10 presents the two categories of cost pressure forces regulated distribution grid operators have to cope with at present: (i) cost cutting incentives according to the currently implemented incentive regulation models (left); (ii) a variety of currently unconsidered extra cost drivers in case of large-scale DG/RES-E grid integration on distribution level (right).

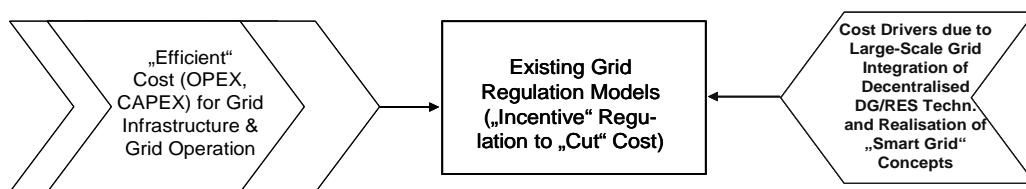


Figure 10. Problem of asset stranding in existing grid regulation models due to unconsidered cost drivers caused by large-scale DG/RES-E integration.

Selected examples of currently non considered extra cost drivers on distribution grid level caused by large-scale DG/RES-E integration are as follows:¹²

- Completely new design criteria and operational concepts are necessary due to bidirectional load flows in case of significant amounts of DG/RES-E generation.
- Significant reinforcements, upgrades and extensions of existing network infrastructure elements (overhead lines, cables, transformers, switching devices, etc.) are necessary.
- Higher technical standards and new concepts for ancillary service provision like voltage and frequency regulation, accounting and billing devices and procedures are necessary.
- The installation of new information and communication technologies

¹² Besides extra cost drivers caused by large-scale DG/RES-E integration there exist a variety of further inherent cost drivers for distribution grid operators. The main “traditional” cost drivers on distribution networks are the provision of overall capacity taking into consideration power flows, voltage level and fault level issues, and the time of use as this drives overall peak requirements. Absolute volume delivered on the distribution system usually is not to be a significant cost driver by distribution grid operators. Furthermore, regulatory incentives to maintain predefined levels of quality of service and to minimize losses also have significant influence on the cost basis of distribution grid operators (see e.g. DTI (2006)).

(ICT) is necessary to be able to manage active and intelligent distribution grids.

- Higher transaction costs have to be taken into account to operate actively managed distribution grids due to the increasing number of market actors.

Due to the fact that the above mentioned extra cost elements for distribution grid operators are not explicitly taken into consideration in the existing grid regulation models – although cost recovery is essential for capital intensive infrastructure investments being effectively sunk once the investment is made – the risk of asset stranding for distribution grid operators is too high. Therefore, based on the existing regulatory environment distribution grid operators might not be willing to integrate DG/RES-E projects on a large-scale.

From the distribution grid operator's point-of-view, the disincentives for any kind of investment into the existing grid infrastructure can be immediately derived from the grid regulation formula. The basic incentive regulation formula widely used in practice is as follows:

$$P_t = P_{t-1} * (1 + RPI - X)$$

where

P_t authorized price-cap in year t

P_{t-1} authorized price-cap in year $(t-1)$

RPI annual inflation index (Retail Price Index)

X productivity offset

This formula determines the authorized price (tariff) a grid operation can set within a regulatory period, incorporating also efficiency improvements (based on cost benchmarking) over the years.

Regardless of investments into the distribution grid infrastructure in the context of DG/RES-E integration, any investment decision of a grid operator is based on the basic economic criterion that maximises revenues minus cost over a predefined period. In detail, the analytical framework describing an economic decision for the most common incentive regulation models (price-caps and revenue caps) looks as follows:

Price-Caps:

$$\text{Profit } \pi = \max_{x,c} px - c \quad \text{whereas} \quad p = \text{fixed} \quad x, c = \text{variable}$$

Revenue-Caps:

$$\text{Profit } \pi = \max_{p,x,c} px - c \quad \text{whereas} \quad p, x, c = \text{variable}$$

The most obvious difference between the price-cap and revenue-cap regulation model shown above is the degree of freedom for setting several different parameters independently, which determines revenues and cost. Whereas in case of revenue-caps several parameters (price, quantity, cost) are variable, this is the case only for quantity and cost for price-cap regulation models.¹³ However, when addressing changes of the cost basis of grid operators – *ceteris paribus* – there is no difference for the two most prominent grid regulation models presented above.

In the following, a thought experiment shall demonstrate the reluctance of distribution grid operators (being subject to “ex-post” oriented price-cap or revenue-cap regulation) to invest into the grid infrastructure, in general, and to accept extra cost for the provision of technical infrastructure and equipment enabling large-scale DG/RES-E grid integration in particular:

- If $c_{DG/RES}$ ($c_{DG/RES} > 0$) is assumed to be the extra cost for grid operators driven by the integration of large-scale DG/RES-E generation facilities, the initial cost basis c of a distribution grid operator is increased to $c_{new} = c + c_{DG/RES}$.
- If these extra cost are not eligible in the grid regulation model (i.e. the extra cost cannot be socialised in the grid tariffs directly) there is no incentive for distribution grid operators to favour any DG/RES-E connection, simply because increasing DG/RES-E integration cost decrease profits (i.e. revenue minus cost):

¹³ An example demonstrating differences of the two incentive regulation models is e.g. the problem to implement energy efficiency initiatives in case of price-cap regulation models as a result of strong incentive for grid operators to maximise quantity (i.e. electricity delivered) and, subsequently, profits rather than to decrease the amount of electricity delivered.

$$\left. \frac{\partial \pi}{\partial c_{\text{new}}} \right|_{c,x,p=\text{constant}} < 0$$

This analytical relationship impressively demonstrates why currently implemented grid regulation models result in reluctant investment behaviour of distribution grid operators in general and as far as DG/RES-E grid integration is addressed in particular.

5.2. Recent innovations in the grid regulation model in the United Kingdom

The UK has a long tradition in regulating its electricity distribution grids based on incentive regulation models. Already in 1995 the regulator has implemented price-cap regulation. Although the price-cap regulation model has fulfilled its purpose (i.e. improving cost efficiency) in the two regulatory periods from 1995-2000 and 2000-2005, in the course of time the disincentives for investments into the distribution grid infrastructure have become increasingly obvious. Moreover, in the UK empirical evidence has become increasingly visible on the reluctance of investments into the distribution grid infrastructure.

Therefore, in 2005 fundamental amendments of the distribution grid regulation model have been conducted, trying to trigger both: (i) traditional investments into the distribution grid for maintenance of the infrastructure assets and (ii) extra investments to provide a level playing field for accelerated grid integration of DG/RES-E generation technologies. More precisely, the two dimensions of changes of the incentive regulation model in UK are as follows:

- the philosophy of allocating DG/RES-E grid integration cost has been changed from deep to shallow charging and
- the extension of the traditional price-cap regulation formula now explicitly considers an “ex-ante” element, enabling direct socialisation of extra grid-related cost for DG/RES-E integration in the grid tariffs.

In detail, the following amendments of UK’s incentive regulation model have been conducted in April 2005 (see e.g. DTI (2006)):

- Same Boundaries on both Ends of the Grid: Prior to April 2005, demand and generation customers were charged differently on distribution grid level. DG/RES-E generators paid connection charges for all measures required to integrate them into the distribution grid (i.e. deep integration approach) whereas demand customers paid more limited connection charges (i.e. shallow integration approach).¹⁴ In April 2005, a common connection boundary has been introduced across generation and demand, i.e. new DG/RES-E generators connecting to the distribution grid now also pay shallow connection charges.
- Socialisation of Integration Cost: Distribution grid operators are allowed to recover their grid-related connection and integration cost of DG/RES generation facilities directly in the distribution grid tariffs by a combination of pass through (80% of connection cost) and an incentive per kW_{DG/RES} connected (2.16 €₂₀₀₆/kW_{DG/RES} (singular) and 1.44€₂₀₀₆/kW_{DG/RES}/yr (annually)).
- Innovation Funding Incentive (IFI): The IFI intendeds to provide funding for particular DG/RES-E integration projects focused on the technical development of distribution networks to deliver extra value (i.e. financial, supply quality, environmental, safety) to end consumers. IFI projects can incorporate any aspect of distribution system asset management including connection of DG/RES-E generation facilities. A distribution grid operator is allowed to spend up to 0.5% of its annual revenue on eligible IFI projects and can socialise a significant amount of associated cost from its network users (e.g. 90% in 2005/2006).
- Registered Power Zones (RPZ): In contrast to the IFI, RPZ focus specifically on the connection of DG/RES-E generation facilities to distribution grids. RPZ intend to encourage distribution grid operators to develop and demonstrate new, more cost effective ways of connecting and operating DG/RES-E generation facilities. For licensed RPZ, the incentive element per kW_{DG/RES} of DG/RES-E generation facility connected is increased for the first five years of operation from 2.16 €₂₀₀₆/kW_{DG/RES} to 4.3 €₂₀₀₆/kW_{DG/RES}.

¹⁴ Distribution grid operators are provided with a revenue stream from demand customers by so-called 'Distribution Use of System Charges (DUoS)' covering the ongoing provision of the distribution grid and spreading the cost of connection of demand customers over the long-term.

6. Conclusions

Taking into account the basic evaluation criteria – minimizing the extra costs for all electricity customers to maximize acceptance – the most important conclusions of this analysis with respect to promotion strategies are:

- Regardless of which strategy is chosen, it is of paramount importance that a promotional system puts strong focus on new capacities which are currently not yet cost-effective and does not mix existing (at least fully depreciated) and new capacities;
- Ensure the credibility of the system. It must be guaranteed with high credibility that the promotion strategy survives a specified planning horizon. Otherwise, the uncertainty for potential investors is too high and it is likely that no investments at all take place;
- Promotion strategies with low policy risks have lower profit requirements for investors and, hence, cause lower costs to society;
- Technology-specific support should reflect learning by including a decreasing dynamic component;
- Currently a well-designed (dynamic) feed-in tariff system ensures the fastest deployment of RES-E at the lowest cost to society.

The major conclusions regarding the grid integration of RES-E are:

- It is important to bear in mind that different cost elements of RES-E integration exist: RES-E power plant, grid connection, grid reinforcement/extension and system operation;
- The cost allocation policy of these disaggregated cost elements also affects economics (generation cost) of RES-E technologies and, subsequently, RES-E deployment. E.g., for the location selection of RES-E sites a trade-off is often necessary between best generation sites and conditions for grid access;
- Achieve unbundling: a clear definition of the boundary between RES-E

- power plant and the grid infrastructure is necessary. A super-shallow or at least shallow RES-E integration approach (incl. transparent locational signals) is clearly preferable compared to deep RES-E integration;
- Take into account the grid operator’s point of view: Large-scale RES-E grid integration cannot take place at the expense of market actors like grid operators. Grid operators are actually facing the problem of cost recovery (i.e. inclusion into the grid tariffs) of RES-E related grid integration cost in the grid regulation process mainly emphasizing cost cutting incentives. An ex-ante mechanism in the grid regulation for cost recovery provides incentives for grid operators to invest;
 - Finally, establish markets in system operation to mitigate variability of large-scale RES-E (mainly wind) generation: support technological development (e.g. wind forecasting), improve regulatory framework (e.g. shorter gate closure, continuous day-ahead markets) and increasingly implement market mechanisms in system operation (with an extended geographical coverage compared to the status quo) caused by variable RES-E (mainly wind) generation.

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