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Published in:
Renewable Energy

Link to article, DOI:
10.1016/j.renene.2010.12.015

Publication date:
2011

Citation (APA):
Ropenus, S., Jacobsen, H., & Schröder, S. T. (2011). Network Regulation and Support Schemes - How Policy Interactions Affect the Integration of Distributed Generation. Renewable Energy, 36(7), 1949-1956. DOI: 10.1016/j.renene.2010.12.015

Network Regulation and Support Schemes – How Policy Interactions Affect the Integration of Distributed Generation

Postprint

Renewable Energy **36** , issue 7, p. 1949-1956.

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Abstract

This article seeks to investigate the interactions between the policy dimensions of support schemes and network regulation and how they affect distributed generation. Firstly, the incentives of distributed generators and distribution system operators are examined. Frequently there exists a trade-off between the incentives for these two market agents to facilitate the integration of distributed generation. Secondly, the interaction of these policy dimensions is analyzed, including case studies based on five EU Member States. Aspects of operational nature and investments in grid and distributed generation facilities are covered. The question in which policy segment to incorporate locational signals is at the heart of the debate.

Keywords: Renewable Energy**;** Distributed Generation; Support Schemes; Network Regulation

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1 INTRODUCTION

The Brussels European Council of March 2007 [1] (Council of the European Union, 2007) endorsed four targets to be achieved by 2020: a reduction in greenhouse gas emissions by at least 20 percent compared to 1990 levels, an increase in energy efficiency in order to save 20 percent of the European Union’s energy consumption compared to projections for 2020, a mandatory target of a 20 percent share of renewables in overall EU energy consumption, and a binding minimum target of 10 percent for energy from renewable sources in transport. Increasing shares of electricity from distributed generation (DG), in particular based on renewable energy sources (RES), will contribute to the attainment of these ambitious policy goals. The EU provides a generic definition of distributed generation as “generation plants connected to the distribution system” [2] (Art. 2 (31), Dir. 2009/72/EC). This paper applies the closely aligned definition by

[3] Ackermann *et al.* (2001): "distributed generation is an electric power source connected directly to the distribution system or on the customer site of the meter" (p. 201). Distributed generation encompasses a variety of technologies, such as electricity generation from renewable energy sources (RES-E) and combined heat and power (CHP). It is well acknowledged that it constitutes a key element for achieving the three objectives of European energy policy, i.e., competitiveness, sustainability and security of supply (CEC, DG). Despite many benefits associated with DG, such as stimulation of competition, reduction in greenhouse gas emissions and increase in energy efficiency (*ibid*), DG/RES integration may also add to the costs and complexity of network operation for distribution system operators (DSOs). The actual impact of a DG/RES plant tends to be highly technology-, time- and site-specific [4] (Leprich and Bauknecht, 2004).

Member States have adopted different kinds of support schemes to promote electricity from renewable energy sources and combined heat and power, ranging from feed-in tariffs to market-based quota systems. Simultaneously, various network regulation approaches are in place, comprising rate-of-return, incentive and yardstick regulation. National regulation and the vertical structure of the electricity sector shape the incentives of market agents, notably of distributed generators and network operators. Based on findings from the IMPROGRES project, this paper analyzes the interactions between the policy dimensions of support schemes and network regulation and how they affect the deployment of distributed generation. The focus is on the impact of different regulatory regimes on DG producers and DSOs. The remainder of this paper is organized as follows: Section 2 presents European Union (EU) legislation on DG to provide an understanding of the legal framework. Section 3 applies a conceptual analysis on the impact of unbundling, access and network regulation as well as support schemes on DG producers and DSOs, respectively. Section 4 illustrates the application of regulation in practice by a case study of five European Member States. Finally, in Section 5 findings are discussed. In Section 6 conclusions are drawn and, based on those, a policy recommendation is suggested.

2 EU LEGISLATION ON DISTRIBUTED GENERATION

At the European level, until today there exists no explicit coherent policy framework on DG. This may partially be attributed to the fact that DG comprises different technologies with distinct characteristics (e.g., for some technologies natural variability of the primary energy source), installations for various types of use, as well as different, albeit rather small, capacity sizes. Several Directives adopted by the EU contain provisions that encompass DG. Not all of the relevant provisions address DG directly as such. Frequently, a DG installation may be encompassed due to its specific technological characteristics that, e.g., qualify it for the entitlement to a financial support scheme. Notably, Directives are not directly applicable (in contrast to Regulations), but have direct effect, i.e., they are binding as to the result to be achieved, "but shall leave to the national authorities the choice of form and methods" (Art. 249, EC Treaty). That is, the implementation of Directives is to the discretion of Member States. As a result, Member States may opt for different forms and methods for the transposition of Directives into national law taking account of national circumstances.

For renewable-based DG, particular importance can be attached to four Directives: the Electricity Market Directive, [2] 2009/72/EC (repealing the previous [5] Directive 2003/54/EC), [6] Directive 2009/28/EC on the promotion of the use of energy from renewable sources[1], [9] Directive 2004/8/EC on the promotion of cogeneration based on a useful heat demand and [10] Directive 2005/89/EC concerning measures to safeguard security of electricity supply and infrastructure investment.

[1] This new Directive amends and subsequently repeals [7] Directives 2001/77/EC and [8] 2003/30/EC.

[2] Directive 2009/72/EC stipulates common rules for electricity generation, transmission, distribution and supply in the internal market in electricity. This encompasses the organization of the electricity sector, authorization and tendering procedures for new capacity, third party access, market opening as well as the independence, duties and powers of national regulatory authorities. Importantly, [2] Directive 2009/72/EC also lays down provisions on the designation, unbundling, tasks and independence of transmission system operators (TSOs) and distribution system operators. Unbundling means the effective separation of networks from the activities of generation and supply ((9), [2] Directive 2009/72/EC). Specific reference to DG is made in several articles of the Directive: in (36), the Directive establishes that when fixing or approving tariffs or methodologies underlying their calculation, "national regulatory authorities should ensure that transmission and distribution tariffs are non-discriminatory and cost-reflective, and should take account of the long-term, marginal, avoided network costs from distributed generation and demand-side management measures". Furthermore, it is for the Member States to ensure that specific authorization procedures shall be in place for small decentralized/distributed generation so as to account for their limited size and potential impact (Art. 7(3)). Also, DSOs shall consider DG that might supplant the need to upgrade or replace electricity capacity in the planning of their network development (Art. 25(7)). Finally, the regulatory authorities shall take all reasonable measures that help to achieve, amongst other aspects, the integration of large and small-scale production of electricity from renewable energy sources and distributed generation in both transmission and distribution networks (Art. 36d).

DG generators may receive support for their renewable electricity production in line with [6] Directive 2009/28/EC ("Renewables Directive"). This Directive stipulates mandatory national overall targets for reaching the target of at least a 20 percent share of energy from renewable sources in the Community's gross final consumption of energy in 2020. In addition to the adoption of national support schemes, Member States are now also allowed to take measures of cooperation with other Member States and/or third countries so as to facilitate the fulfillment of their mandatory national 2020 targets. Such measures of cooperation may include joint projects, agreements between Member States on statistical transfers of renewable energy as well as joint or partly coordinated national support schemes among Member States. By the same token, operators of DG units based on combined heat and power (CHP) may receive direct or indirect support in accordance with support schemes adopted by the Member States to implement [9] Directive 2004/8/EC ("CHP Directive"). In addition, Art. 8 (3) of Directive 2004/8/EC states that, subject to notification to the Commission, Member States may particularly facilitate grid access for power produced by small-scale and micro-generation units. Notably, both regarding the Renewables Directive and the CHP Directive, the eligibility of electricity generators for receiving financial support is based on technological characteristics and not on being DG producers as such.

Eventually, mention of DG is made in the "Security of Supply Directive" [10] 2005/89/EC. The objective of this Directive is to ensure an adequate level of generation capacity, an adequate balance between supply and demand, as well as an appropriate level of interconnection between the Member States (Art. 1). With respect to DG, Art. 3(3) underlines the importance of "encouraging energy efficiency and the adoption of new technologies, in particular demand management technologies, renewable energy technologies and distributed generation".

3 NATIONAL POLICY: THE POLAR INCENTIVES OF DISTRIBUTED GENERATORS AND DISTRIBUTION SYSTEM OPERATORS[2]

This section provides a conceptual analysis of different policy dimensions which influence the interaction of DG/RES operators and DSOs. This conceptual analysis for each policy area can be subdivided into two steps: firstly, there will be a review of the existing relevant legislation at the European level to be implemented by the Member States. Secondly, the implications for the (partially conflicting) incentives of DG/RES producers and DSOs will be discussed.

3.1 Level of integration between DSOs and DG/RES generation

Vertical industry structure is a significant influencing factor for the incentives of market actors. As for distributed generation, vertical industry structure refers to the vertical relationship between the DSOs and the generation segment, i.e., DG/RES producers[3]. Networks constitute essential facilities with natural monopoly characteristics. The guarantee of fair and non-discriminatory network access for all DG/RES producers is hence a prerequisite for the establishment of a level playing field. [2] Directive 2009/72/EC stipulates legal and management unbundling for DSOs (Art. 26(1)) as well as unbundling of accounts (Art. 31(3)). Notably, an exemption from the unbundling requirements may be applied to small DSOs serving less than 100,000 connected customers, or serving small isolated systems (Art. 26(4)). The implementation of the exemption clause is to the discretion of the Member States. Furthermore, [2] Directive 2009/72/EC allows combined operators (Art. 29), that is, a combined transmission and distribution operator. Also, in [2] Directive 2009/72/EC (Art. 26(3)), it has been added that the activities of vertically integrated DSOs should be monitored by the regulatory authorities so that the former cannot take advantage of their vertical integration to distort competition.

The conflict of interest of network owners that also operate in the competitive segment (e.g., electricity generation) in the provision of access to competitors has been covered substantially by microeconomic literature. [12] Armstrong *et al.* (1994) raise the question of vertical structure, i.e., whether a firm should be allowed into the deregulated segment, or rather be ring-fenced and solely confined to the natural monopoly segment. [13] Salop and Scheffman (1983) point out the problem of a dominant firm's incentive of raising rivals' cost when the dominant firm has control over an essential input, such as the network. Naturally, regulation of network access charges and tariffs would mitigate or, ideally, preclude an aggravation of access to the essential facility. In reality, however, there is not perfect information so that it may be more effective to remove the potentially inherent incentive to use the control of the essential facility for delimiting entry of competitors by means of unbundling.

3.1.1 Impact on DG/RES producer

For a DG/RES operator, the danger of encountering an aggravation of network access (e.g., through prohibitively high connection charges) cannot be disentangled from regulatory oversight and the effectiveness of regulation. This comprises transparency on the methodology and the determination of network costs arising from a new connection. Also, it plays a major role whether there are regulated connection charges and network tariffs vs. negotiated charges and tariffs between DSOs and DG/RES producers. However, there is also another side to the coin: a DSO operating and owning DG/RES units itself has more experience in the system integration of DG/RES. This in turn may benefit the integration of new (competing) DG/RES producers provided that non-discriminatory network access is realized.

[2] Portions of this section draw on the IMPROGRES Deliverable 3 [11] (Ropenus, Schröder, Jacobsen *et al.*, 2009).

[3] We refrain from covering the vertical relationship between DSOs and the supply sector in this analysis.

3.1.2 Impact on DSO

If DSOs are allowed to own and operate DG/RES units themselves, the synergies between the generation and the network segment can be realized in a more efficient manner. For example, the DSO may then decide to delay or substitute network reinforcements through the appropriate placement of distributed generation capacity. Furthermore, this may provide an additional incentive for the DSO's role in active network management rather than treating the distribution network as a passive appendage to the transmission network. With regard to the network access problem, the (in some cases possibly negligible) danger of vertical foreclosure on a local scale by aggravating network access for new small-scale DG entrants needs to be weighted against the problems if unbundling is imposed on small vertically integrated DSOs. In particular, DSOs falling under the exemption clause represent small undertakings in the integrated European electricity market for which unbundling may impose a huge financial burden. Regulation on provisions governing the unbundling of DSOs has to balance the danger of a vertically integrated DSO exercising local market power (e.g., aggravation of network access for competitors in a rural network) against the financial and operational burden unbundling imposes on small DSOs. It may be further subject to discussion whether the exemption clause should be harmonized, or whether it should continue to be to the discretion of Member States.

3.2 Regulation of DSOs

Regulation of DSOs consists of two major elements: connection charges for the initial provision of physical access to the network and the regulation of the network tariff. The methodology applied for the determination of connection charges and tariffs for network usage provides inherently incentives for the DSO to promote or not to promote the connection of new DG/RES generators. Both the choice of the connection charging methodology and of the network regulation regime are to the discretion of the individual Member States.

3.2.1 Connection charges

Three major types of connection charges can be distinguished [14] (Ackermann, 2004): deep, shallowish and shallow charges. Under a deep connection charging regime, the DG/RES producer incurs the costs for connection assets and the costs for all necessary network reinforcements, i.e., at the distribution and at the transmission level. Shallowish connection charges imply that the DG/RES producer has to pay for the costs of connection assets and reinforcements at the distribution level only. If shallow connection charges are applied, the DG/RES producer only incurs the direct costs for connection, and maybe the costs for a new transformer.

3.2.2 Network tariff regulation

The income of TSOs and DSOs is primarily derived from network tariffs. The latter are composed of different fees. Depending on their application in national regulation, these fees may comprise energy charges [MWh], capacity charges [MW], reactive power charges [MVAr] and Use of System (UoS) charges [14] (Ackermann, 2004). It is the duty of regulatory authorities to fix or approve, in accordance with transparent criteria, transmission or distribution tariffs or their underlying methodologies (Art. 37(1a), [2] Directive 2009/72/EC). By the same token, regulatory authorities have the authority to require TSOs and DSOs to modify terms and conditions if necessary, including tariffs and methodologies, so as to ensure that they are proportionate and applied in a non-discriminatory manner (Art. 37(10), *ibid*).

The type of connection charging philosophy, as outlined above, cannot be regarded in isolation from the network tariff. In the case of shallow(ish) connection charges, a DSO may recuperate the reinforcement costs through UoS charges on generators and/or consumers. The simplest kind of UoS charge is a postage stamp tariff, where transmission/distribution charges paid by a certain group of generators/consumers are uniform, i.e., they incur the same charges regardless of their location and time of use. The underlying idea of introducing UoS charge differentiations is that different parties connected to the grid should pay the share of system usage they need. In sum, these charges represent the DSO's revenue and need to be equivalent to its allowed revenue. This can be implemented by a multitude of different approaches: either both consumers and generators or only consumers can pay UoS charges. Furthermore, UoS charges can vary according to the voltage level each agent is connected to, or according to the location of agents (nodal/zonal pricing).

EU Member States have adopted different kinds of network regulation approaches. The predominant types are rate-of-return regulation, incentive regulation and yardstick regulation (cf. [15] Joskow, 2006; [16] Viljainen, 2005). Under a rate-of-return (RoR) or cost-plus regulation, the regulator approves a cost base which is used to calculate the total allowed revenue for a network operator in one period. A fixed interest rate is then given on the bound capital. In the meantime, many Member States have migrated to incentive regulation in the form of price cap or revenue cap regulation. A nowadays widely practiced way of network incentive regulation is the *revenue cap*: the regulator imposes a maximum price (€/kWh) or maximum revenue (€) on transmission and distribution companies for one regulatory period. The regulator then defines a price path for the next regulatory period. The incentive for the companies is to decrease their own cost in comparison to this predefined price path; the difference constitutes their profit. This can also be combined with stronger requirements for companies that are inefficient in comparison to their peer group (individual X-factor). Finally, yardstick competition is an incentive mechanism where a network operator's allowed expenses depend on the average of the industry peer group for every single period. It is therefore more competitive than price or revenue cap regulation. In practice, various hybrid forms between the aforementioned approaches exist.

3.2.3 Impact on DG/RES producer

The type of connection charge methodology allocates the costs and risks between DG/RES producers and DSOs. Whereas the DSO recuperates charges directly upfront under a deep connection charging regime, the implementation of shallow charges implies for the DSO that it recovers cost over time, e.g., by means of UoS charges. As for DG/RES producers, it is quite apparent that there is a preference for shallow charges. Not only are the financial expenses upfront significantly lower, but also risk exposure is reduced: under deep connection charges, there is always a high degree of uncertainty which network reinforcements are considered necessary for the new DG/RES plant as well as on how their costs will be determined. As for UoS charges, DG/RES operators obviously prefer when those are borne by consumers only.

3.2.4 Impact on DSO

For the DSO, deep connection charges are the most preferable approach: this is because they both send a very strong locational signal for the placement of new DG units and because they allow the DSO to cover the costs for connection immediately instead of socializing and recuperating them over time. Location-differentiated UoS charges also provide locational signals, yet their immediate effect for the siting of new DG/RES plants is not as strong as an upfront payment. In addition, location-differentiated UoS charges would prove to be highly complex in practical implementation.

In general, the difficulty lies in the trade-off between the allocation of network costs and the provision of locational signals while simultaneously giving incentives for the erection of new DG/RES plants. One possibility is the application of shallow connection charges coupled with UoS charges to be paid by the DG/RES producer. However, this DG/RES UoS charge should not be higher than for conventional generation connected to the transmission network.

3.3 Remuneration of DG/RES producers

For the most part, DG producers deploy technologies that qualify them for the entitlement to national support schemes. In line with the "Renewables Directive" [6] 2009/28/EC and the "CHP Directive" [9] 2004/8/EC, Member States may apply national support schemes to encourage electricity generated from renewable energy sources and from combined heat and power. In general, support mechanisms can be divided into investment support and operational support. Investment support comprises capital grants as well as fiscal incentives/exemptions. As for operating support, there is a distinction between price-based schemes, such as the classical feed-in tariff and price premiums, and quantity-based schemes, notably quota systems with tradable green certificates.

Under the classical feed-in tariff scheme, qualified electricity producers receive a fixed price per kWh of electricity fed into the grid. This pre-set tariff is set to a level above the market price and granted for a specific duration, e.g., 20 years, so as to provide investment certainty. Commonly, this scheme is coupled with priority access to the grid as well as priority dispatch for qualified generators. Price premiums constitute a market-based variant of the feed-in tariff. Here, a fixed premium is paid on top of the market price, frequently supplemented by a premium for balancing costs. Both price-based support schemes are typically financed by means of socializing the associated costs.

By contrast, in the case of a quota system, not the price but the quantity of renewable electricity is stipulated as a percentage share of total electricity consumption or production. For each unit of renewable electricity fed into the network (typically, corresponding to one MWh), qualified producers of renewable electricity obtain one green certificate. The latter can be sold on a separate financial certificate market. If the obligation is imposed on consumers, electricity suppliers/retailers typically act on their behalf as buyers on the certificate market. The selling of green certificates implies a second revenue stream for renewable electricity producers: they do not only obtain the electricity market price, but receive additionally the certificate price.

3.3.1 Impact on DG/RES producers

The remuneration is crucial for DG/RES producers in two respects: firstly, many DG/RES technologies are not mature yet in commercial terms (disregarding potential externalities of conventional production) and therefore need financial support to sustain in the market. Secondly, quota systems, the price premium and the feed-in tariff expose DG/RES producers to different degrees to the volatility of market prices. A greater exposure under price premiums and quota systems incentivizes producers to follow load patterns and may be more efficient from a system operation point of view; however, dependent on the evolution of market prices this may also imply greater uncertainty for DG/RES producers in terms of their revenue as compared to a fixed feed-in tariff granted for 20 years. Also, in the absence of adequate storage possibilities, load-following electricity production may prove difficult to implement for technologies with natural (wind) or operational variability (CHP where electricity generation is dictated by heat demand). Notably, the investment certainty associated with high levels of support may mitigate some entry barriers, such as high connection charges or network tariffs that negatively affect the profit of the DG/RES producer. However, in such cases it would be more efficient to adopt changes directly in the network access regulation segment.

3.3.2 Impact on DSO

The DSO is affected by the applied support scheme in various ways: firstly, the level of support determines the aggregate penetration of DG in DSO networks and may increase DSO network costs. Secondly, controllable, i.e., non-variable, DG/RES units may be more responsive to electricity market price signals and actual demand under the more market oriented support schemes. This may facilitate their integration in terms of network operation and to a lesser extent reduce network reinforcement costs. The provision of priority access implies an additional burden for DSOs, in particular if DG/RES units are sited predominantly with respect to natural resource conditions, but not from a network point of view. Therefore, it is vital that connection charges and UoS charges provide locational signals for the optimal siting of new DG/RES plants. One possibility to include network signals in the support schemes is to incorporate a bonus for location of DG investment or for the provision of ancillary services. Another possibility is the adoption of a dispatch bonus for operating at times when the network is constrained or deviates from plans. However, support schemes, in particular the feed-in tariff, may not result in cross-subsidizing network costs by inducing the DSOs to set higher connection charge levels. Feed-in tariff schemes are not dynamically adjustable and, therefore, they are inefficient in providing signals for investment in the individual grid where it is most beneficial. It is more efficient to provide direct signals in the network segment itself by encouraging the DSOs to provide these signals to potential DG investors.

4 INTERACTIONS – COUNTRY CASES

This section deals with a country-based analysis of the different regulatory areas in the five selected countries and draws mainly on the IMPROGRES project report by [17] Cali, Ropenus and Schröder (2009). The individual characteristics of every country are described. Subsequently, Section 5 provides a comparative analysis of the countries and a discussion of implications of the current regulatory combinations.

4.1 Denmark

Denmark has 101 distribution system operators that vary strongly in size and of which 96 serve less than 100,000 customers. All DSOs are legally unbundled. Notably, Denmark does not apply the exemption clause on DSO unbundling [18] (CEC, 2009). The fragmented structure of the distribution segment can be attributed to the historical background of local electricity supply with consumer or municipal ownership. Consumer proximity to the energy sector might be one of the explanations why wind generation cooperatives have been established widely. Since 1977, DSOs were subject to price supervision by an Electricity Price Council [19] (Moll Sørensen, 2005). This has been modified with the introduction of a revenue cap incentive regulation in 2000. However, the effectiveness of this new regulation scheme has been rather moderate so far (see [19] Moll Sørensen, 2005, for further details). With respect to obtaining physical network access, DG operators have to pay only shallow connection charges when accessing the network, and only a few have to pay generator use-of-system charges.

In the early beginnings of wind power development, the technology was supported by research funds and the obligation on utilities that they had to buy wind-generated power at 85 percent of the household customer price in the supply area and pay 35 percent of the connection costs [20] (Vleuten and Raven, 2006). CHP development was fostered by a feed-in tariff with three time-dependent steps which was replaced by a price premium in 2005 to counter problems with excess production. A similar development can be observed for the feed-in tariffs for the different renewable electricity generation technologies. Before the Danish electricity reform in 1999 and also directly thereafter, fixed feed-in tariffs were applied. The adoption of a green quota system was considered, but subsequently postponed until it will be possible to establish a common market with several EU Member States. Instead, there was a migration to price premiums in 2003, i.e., producers had to sell their electricity on the market and received a fixed premium on top of the electricity market price. Depending on the year of commissioning of an installation, either the level of the premium or the level of the overall income was guaranteed. In 2008, a new separate law on renewable energy was adopted. The support, now a pure price premium, was raised for biomass, biogas and wind power.

4.2 Germany

In Germany, there are 855 distribution system operators of which 150 are legally unbundled and 779 serve less than 100,000 customers so that they may fall under the exemption clause that is applied in Germany [18] (CEC, 2009). With regard to network regulation, DSOs are subject to a revenue cap incentive regulation since 2009. The incentive regulation generally accounts for distributed generation, but does not allow a higher revenue cap due to, e.g., higher network losses. Generators pay shallow connection charges and no use-of-system charges. The handling of network congestions due to a faster growth of wind generation capacity than network reinforcements is interesting: until 2008, wind generators could be curtailed without getting any compensation for the curtailment. Under current legislation, they receive the value of the energy they would have produced in an uncurtailed situation. This way, the question about the optimum between curtailment of DG units and network reinforcement is internalized in the network operator's business [21] (EEG 2009, §11-12).

Renewable energy sources account for about 15 percent of total electricity generation in Germany [22] (Eurostat), with the predominant generation from renewables being wind, biomass and hydropower (with strong regional differences). The amount of photovoltaic generation capacity is also strongly increasing.

In Germany, the instrument for the promotion of renewable energy is a fixed feed-in tariff that was initially introduced by the Energy Feed-In Law [23] (*Stromeinspeisegesetz*, 1990) in 1990 where support was coupled to historical retail prices. This was modified ten years later by The Act on Granting Priority to Renewable Energy Sources [24] (EEG, 2000) where fixed feed-in payments are guaranteed for a (maximum) period of 20 years, with differentiation according to technologies. Under the EEG, grid operators are obliged to connect renewable electricity generators to their networks, purchase the latter's electricity as a priority and compensate them with the feed-in tariff as laid down by the EEG. There is an initial tariff period with a higher feed-in tariff for the first years after commissioning of a plant (e.g., for the initial 5 or 12 years). In 2004, a revision of the EEG was implemented with modified tariff levels [25] (EEG, 2004). The latest revision of the EEG in 2009 [21] (EEG, 2009) introduced the option for renewable electricity generators to choose between the regular feed-in tariff scheme and the direct selling of their electricity on the market on a monthly basis. Furthermore, there is now a system services bonus for the remuneration of wind paid in addition to the initial tariff for five years to installations that meet specific technical requirements. The support scheme for CHP is a price premium on top of the market price. This applies also for micro-CHP units connected to the distribution networks.

4.3 The Netherlands

In the Netherlands, there are eight distribution system operators in total. All of them are legally unbundled, and five of them serve less than 100,000 customers [18] (CEC, 2009). Similar to Denmark, the exemption clause for small DSOs has not been adopted in the Netherlands (*ibid*). Incentive regulation of the distribution system operators has been in place since 2001, and the design has progressively turned more advanced. Today, it reflects a quality factor, but does not account for different cost structures due to different geographical integration of DG/RES units in single networks. Generators are subject to shallow or negotiated deep connection charges depending on the capacity of the connection: up to 10 MVA, shallow connection charges are to be paid, whereas deep connection charges apply for larger units. DG/RES units do not have to pay use-of-system charges in the Netherlands. Congestion management is necessary in some parts of the country, and obtaining grid access can cause delays in these regions. A law giving priority to DG/RES units in comparison to fossil-based units is being discussed.

Due to the dense population of the country and the importance of greenhouse agriculture, CHP plays an important role. It accounted for about 9 GW of generation capacity in 2006 (excluding coal-fired units, [26] (Daniëls *et al.*, 2007)). Until 2000, CHP was supported through priority access, a fixed feed-in tariff and several tax measures. Until 2005, a price premium was determined annually. It has effectively been abolished after 2005 because the electricity prices rose to a level that support was considered superfluous.

Renewable energy is predominantly supported with a price premium scheme, but the level and detailed design were varying over time [27] (SOLID-DER, 2008): from 2006-2008, the instrument was abolished. A quantitative change occurred due to the change from a fixed premium to a variable premium, dependent on the market price level. The units are commonly sold on liberalized electricity markets with aggregators as intermediates; these can charge about 0.4 to 0.8c €/kWh for being balancing-responsible.

4.4 Spain

In Spain, there are 329 distribution system operators all of which are legally unbundled although 323 DSOs serve less than 100,000 customers and can fall under the exemption clause [18] (CEC, 2009). Spanish distribution system operators are regulated by a revenue cap incentive regulation that includes power quality standards. In contrast to the other countries, which apply statistical methods to determine single company's efficiency, Spain uses reference network models. However, incremental cost related to the connection and operation of DG/RES is not represented in a satisfactory way. "DG/RES pay deep distribution connection charges in Spain, i.e., DG/RES has to pay for any equipment and network reinforcement that is required to meet the technical conditions. The amount of these connection charges is calculated by the corresponding DSO. The rules for this calculation are not simple or transparent, thus discriminatory treatment may arise. DG does not pay use-of-system charges. As long as use-of-system charges for DG/RES are not implemented, main network reinforcement costs are socialized among consumers."[4] Spain introduced its first feed-in tariff in 1994 (see [27] SOLID-DER, 2008, for further details). Already then, extra payments for the provision of reactive power and time-differentiated tariffs were granted. In 1998, the feed-in tariff was adopted so that its level was based on the average market price of electricity, but did not reflect hourly variations. In 2004, Spain progressed to a hybrid system of feed-in tariffs and price premiums, both being dependent on the average market price of electricity. This average reference price was updated periodically. Since 2007, the hybrid system is no longer dependent on the average tariff. Instead, technology-specific cap and floor values (market price plus premium) were introduced. The law comprises also more technical requirements, such as the obligations for units larger than 10 MW to be connected to a local control centre and requiring all units to have voltage dip ride through capability.

4.5 United Kingdom

In the distribution sector in the United Kingdom, there are 18 DSOs of which 4 DSOs have less than 100,000 customers. The United Kingdom does not apply the exemption clause so that all DSOs are legally unbundled [18] (CEC, 2009). The British distribution system operators have the longest experience with revenue cap incentive regulation, which was introduced in 1990. The cost effect of DG/RES was explicitly taken into account in the latest regulatory review in 2005. The implemented instruments are an innovation-funding incentive scheme and registered power zones. The latter are intended to provide a regulatory framework for certain innovative test regions, e.g., for active network management and DG/RES integration. The DSO's revenue cap is increased if such measures are taken. DG/RES connection charges are negotiated bilaterally and are characterized as shallowish. In single cases, bilateral compensatory payments for curtailment have been reported if this helped the DSO to reduce network reinforcement demand [28] (Lobato *et al.*, 2009).

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[4] Contribution by Olmos, L. to [17] Cali, Ropenus and Schröder (2009).

The support scheme for DG/RES units differs considerably from the other countries: as early as 1990, the Non-Fossil-Fuel Obligation (NFFO) was adopted. It was a tendering mechanism granting subsidization to the bidder with the lowest bid for renewable generation. However, actual construction of the promised generation capacity proved hard to enforce. Due to design flaws, also subsequent to following reforms, the instrument was not particularly effective in attaining a high DG/RES capacity installed. Since 2002, the Renewables Obligation (RO) is in effect. It is a quota system that imposes a percentage requirement on electricity suppliers on the share of electricity from renewable energy sources they deliver to electricity consumers. The stipulated renewable quota increases until March 2015 (to a quota of 0.154) and is then maintained at this level until 2027 to incentivize investment. Qualified electricity generators obtain a green certificate for each unit of renewable electricity produced. Electricity suppliers meet their quota obligation by purchasing the required amount of certificates from electricity producers. In the previous Renewables Obligation Orders, one Renewable Obligation Certificate (ROC) was issued for one MWh of renewable production. The latest revision of the RO in 2009 introduced banding, i.e., one ROC corresponds no longer to one MWh across all technologies, but it is differentiated for the different technologies, accounting for their maturity.

5 DISCUSSION

In the five country cases studied, we can observe a general transition from fixed price-based to more market based support schemes (Figure 1). The changes are mainly a result of rising DG/RES shares and the increased value of flexible operation (market integration) of the DG/RES producers. Recently the trend in the UK has been reversed with a return to feed-in tariffs.

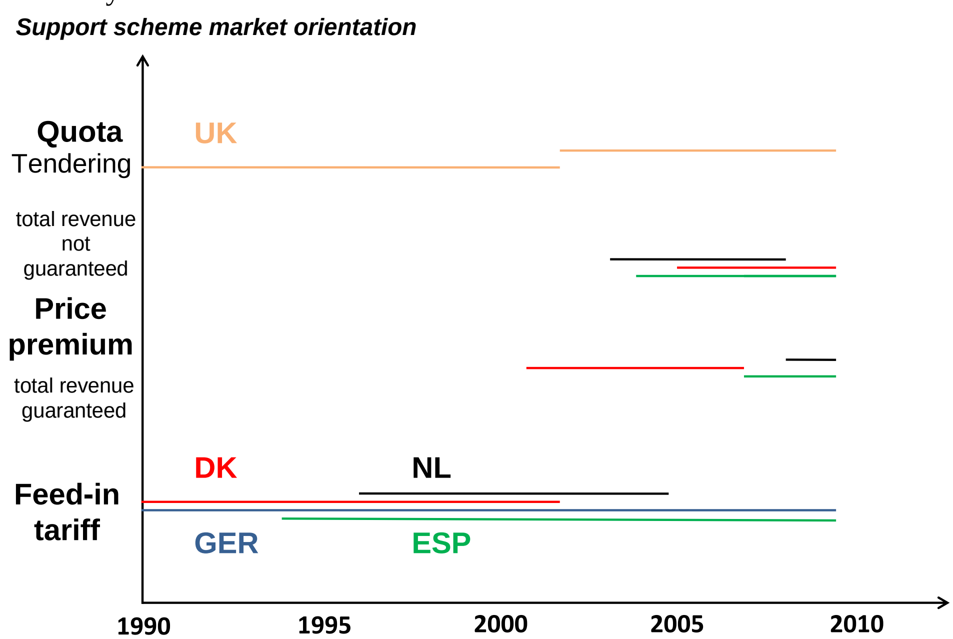

Figure 1: Historical evolution of support schemes in five country cases

In Denmark, the Netherlands and Spain, the promotion schemes have moved from the classic feed-in tariff scheme to price premiums during the past 20 years. Germany, albeit still applying the classic feed-in tariff, allows with the option of direct selling renewable electricity producers to voluntarily participate in the market rather than obtaining a fixed level of support. The UK is the only country among the 5 included here using a quota mechanism as its support mechanism.

Regarding network regulation, there has been convergence among the five examined Member States, with the majority applying revenue cap regulation and the Netherlands having implemented yardstick regulation. By contrast, the choice of connection charging regime has been rather mixed, ranging from deep over shallowish to shallow charges. The matrix depicted by Table 1 provides an overview of the combinations of network and support scheme regulation for the five countries of our case study.

[29] Ragwitz *et al.* (2006) broach the issue of support scheme effectiveness. They find that during the early stages of RES development with low penetration levels of a RES technology, feed-in tariffs turned out to be most effective. From the vantage point of a DG/RES producer, in terms of revenue, a feed-in tariff and shallow connection charges (upper left corner of Table 1) provides a good combination for fostering the deployment of a technology in an early development stage. A more market-based approach with price premiums can be implemented when the respective technology reaches a considerable market penetration level and gets closer to being economically viable in the absence of support.

Table 1: Country matrix with combinations of network and support scheme regulation

	Feed-in tariff	**Price premium**	**Quota system**
Shallow connection charges	Germany (revenue cap)	Denmark (revenue cap) Netherlands (yardstick) (units <10 MVA)	
Shallowish connection charges			United Kingdom (revenue cap)
Deep connection charges	Spain (revenue cap)	Netherlands (yardstick) (units >10 MVA) Spain (revenue cap)	

As for the DSOs, the allocation of the costs for integrating DG/RES plants remains the major issue at stake. In the past, rate-of-return regulation was based on the actual costs incurred by the DSOs. However, under incentive regulation the revenue of DSOs is (at least partially) decoupled from costs. Hence, it is essential to incorporate locational signals for the placement of new DG/RES production in access and network regulation so as to neutralize or at least compensate DSOs for the costs arising from DG/RES integration. Simultaneously, it is important to incentivize the efficient siting of new DG/RES units through the provision of locational signals.
Both a lack of incentive for the DSOs to connect new DG units to their grids and high connection charges have been identified as major barriers to DG deployment by the earlier conducted DG-GRID project [30] (Skytte and Ropenus, 2005). The question therefore arises in which regulatory segment, i.e., network tariff, connection charge or support scheme, to include locational signals for the placement of new DG/RES producers in the network. This will be further touched upon in the subsequent conclusion.

6 CONCLUSION

Our analysis illustrated how the impact of various types of network regulation approaches, connection charging regimes and support schemes differs for DG/RES producers and DSOs. In some policy areas, the impact can nearly be considered to be antagonistic, i.e., it affects these two market agents in opposite directions. In the case of connection charges and network tariffs, DG/RES producers naturally prefer the lowest level of charges attainable whereas it is essential for DSOs to recuperate arising costs and to induce an optimal placement of new DG/RES units from a network point of view. Similarly, for support schemes, the DG prefer the highest support level which results in high penetration of DG/RES that lead to rising costs for the DSOs. With regard to unbundling, the risk of the exercise of local market power through vertical integration of the DSO has to be weighted against more effective network management and planning if small

DSOs are allowed to be vertically integrated. With shallow connection charges the problem of local market power is considerably reduced because the network owner cannot use connection charges as an entry barrier for new competitors to its own generation plants.

The country case study has revealed that, there was until recently among the selected Member States a migration to incentive regulation and more market-based support schemes while the connection charge approaches vary to a larger degree. For the UK this has been partly reversed with the recent move to a higher reliance on feed in tariffs.

For higher penetration levels of DG/RES driven by high support levels, the integration costs in networks rise. The combination of shallow connection charges with the DG generators paying no Use of System charges is problematic because neither support schemes nor network charges provide locational signals with regard to network integration. As aforementioned, this leads to the interesting question in which regulatory segment such locational signals could be included. Inherently, it is in the interest of DG/RES investors to reduce their upfront investment, which indirectly rules out the deep charging approach. Simultaneously, for DSOs it is important that additional generation is placed in locations where they do not require network reinforcements (or, alternatively, to provide locational signals where small-scale generation could be used to substitute or defer network upgrades). The authors suggest that DSOs should be encouraged to plan their network taking into account also possible future DG/RES expansion.

DSOs could then identify areas or single nodes where new DG generation capacity would be beneficial. This way, DG/RES investors would have a clear signal where their generation units could optimally be placed with respect to the network and be rewarded with an upfront “network premium” for example by reducing the connection charge. Notably, the proposed setup would require, firstly, that the DSO is aware about the dynamic conditions of its network and, secondly, that this approach is not to the DSO’s economic disadvantage. More precisely, it would require that the incentive regulation allows the DSO to profit from reduced network costs caused by the improved location of the new DG investments.

7 ACKNOWLEDGEMENTS

This work is part of the research project IMPROGRES (EISAS/EIE/07/137/2007; http://www.improgres.org) supported by the European Commission, Directorate-General for Energy and Transport, under the Energy Intelligent Europe (EIE) Programme. The authors would like to express their gratitude for the support of this project. The IMPROGRES project aims to identify possible improvements in the social optimal outcome of market integration of distributed generation (DG) and electricity production from renewable energy sources (RES-E) in European electricity markets.

Portions of this paper draw on the Deliverables 2 and 3 of Work Package 2. The authors would like to thank all IMPROGRES project partners for the great cooperation and fruitful and inspiring discussions during the project meetings.

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