Utilities Policy 31 (2014) 229–237

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

From distribution networks to smart distribution systems: Rethinking the regulation of European electricity DSOs☆

Sophia Ruester [a,*], Sebastian Schwenen [b], Carlos Batlle [c,d], Ignacio Pérez-Arriaga [c,d]

[a] Florence School of Regulation, European University Institute, Italy
[b] German Institute for Economic Research, Berlin, Germany
[c] Comillas Pontifical University, Madrid, Spain
[d] MIT, Boston, USA

ARTICLE INFO

Article history:
Available online 16 April 2014

Keywords:
Electricity distribution
Smart grid
Regulation
Distribution system operator

ABSTRACT

Distributed energy resources allow for new business models that have the potential to substantially change today's power system functioning paradigm. In particular, these changes pose challenges for distribution system operators (DSOs) and their regulation alike. This article sheds light on missing aspects in current regulation, recognizing DSOs as regulated monopolies, but also as key players along the supply chain. We provide insights on how regulation should be adjusted so that DSOs are incentivized to facilitate the market entry of welfare-enhancing technologies in a timely fashion, and to manage the distribution system efficiently in the presence of distributed energy resources.

1. Introduction

Technological advances are reshaping today's power systems, in particular at the distribution-network level. More mature technologies for local renewable generation have decreased the related investment costs, and national support schemes have led to a significant market penetration of distributed generation (DG) in many EU countries. For instance, in Germany, "in many places, the DG output of distribution networks already exceeds local load – sometimes by multiple times" (Eurelectric, 2013) (p. 3). In addition, distributed storage might soon become viable at all voltage levels and in large amounts, becoming a critical component of "the grid of the future" (see Beaudin et al., 2010; Ruester et al., 2013). Likewise, the use of electric vehicles charging from the grid, and possibly also injecting power back into it and delivering so-called vehicle-to-grid services, is projected to grow (e.g., Kampman et al., 2011; Loisel et al., 2013).

In addition, recent innovations in metering and communication devices enable active demand response and enhanced distribution automation, thereby facilitating and allowing for a wider deployment of distributed generation, local storage and electric vehicles. Whereas at the beginning of the liberalization process demand response was considered only interesting for large, typically industrial, customers, technological advances (for example, intelligent metering and control systems that can optimize individual consumption patterns, thereby reducing risks and efforts related to reacting to price signals) also make this concept interesting for the smaller-scale commercial and residential sectors. According to a positive cost–benefit analysis, at least 80 percent of European households should be equipped with intelligent metering systems by 2020 (European Commission (EC), 2009).

This newly emerging broad range of distributed energy resources (DER) – be it distributed generation, local storage, electric vehicles or demand response – has the potential to drive significant changes in the planning and operation of power systems. These changes bring challenges for electricity distribution system operators (DSOs) and their regulation alike, ranging from increasing uncertainty in distribution grid flows and increasing volatility of net demand to the efficient integration of DER business models into retail markets. In the current state, some challenges are only possibilities that might arise once technologies mature and are more widely deployed. Other challenges, foremost related to DG, are established facts, and concern DSOs already today.

However, the same technologies that are causing substantial challenges can – with the right regulation and market design – be exploited to establish a more efficient, and also cleaner, electricity system than our current one. All DER technologies have the potential to provide downward or upward adjustment to the system; thus, employing and aggregating DER services offers a powerful and flexible tool for power trade, and guaranteeing balanced power

☆ This article belongs to the special issue: 20 years of liberalization of the European network industries.

* Corresponding author.
E-mail address: Sophia.Ruester@eui.eu (S. Ruester).

http://dx.doi.org/10.1016/j.jup.2014.03.007
0957-1787/© 2014 Elsevier Ltd. All rights reserved.

networks. These local resources can provide a diversity of services with economic value, and may successfully compete with centralized generation in offering new tools for system control. A more active distribution system management can help to decrease the total cost of DSOs compared to the traditional “fit-and-forget approach” of merely connecting the new devices to the network (see Pérez-Arriaga, 2013).

Current distribution system structures differ widely among EU Member States, and today’s DSO landscape resembles a patchwork with diverse national implementations of relevant pieces of EU legislation. Substantial differences arise regarding operated voltage levels, the scope of activities, the size and number of DSOs in a country, the level of unbundling, and applied regulatory formulas (see CEER, 2013; European Commission (EC), 2012a; Eurelectric, 2010a). Even though full eligibility of customers is mandatory, and the choice of suppliers and tariffs has increased in many retail markets, the degree of retail market liberalization and competition still varies significantly across the EU. Insufficient unbundling poses one of the most serious obstacles to competition in many distribution markets. This heterogeneity in regulation and market structures and distribution systems aggravates the problem of finding a unanimous approach to appropriate DSO regulation.

In this article, we investigate how regulation and market design can foster an effective integration of distributed energy resources into both retail markets and distribution grid management, with the focal point of the analysis being on European distribution companies. We ask how the regulation of European electricity DSOs should be adjusted so that – with the least friction between the two goals – DSOs are incentivized, first to create a level playing field for the market entry of DER technologies, and second to make use (directly or indirectly) of these local resources to manage the distribution system efficiently.

The article is organized as follows: Section 2 demonstrates how DER technologies boost new business models for local means of electricity trade, and illustrates the resulting challenges for key areas of DSO regulation. Section 3 presents an analysis of the identified key areas of regulation, and highlights what improvements are needed in each area in order to integrate DER into power markets and distribution system operation. After having identified required regulatory adjustments, in Section 4 we discuss whether they should be best pursued at EU or Member State level. Section 5 concludes.

2. Emerging business models challenge DSO regulation

The large-scale introduction of distributed energy resources will be made possible – and also reinforced – by new evolving business models. Successful business models can substantially alter the structure and organization of power systems. To this end, this section first highlights the potential for new business models, before showing how DER challenges the existing regulation of DSOs, and which areas of DSO regulation have to be reviewed in particular.

2.1. Business models arising from DER

Most business models associated with distributed energy resources involve some sort of aggregation, such as the aggregation of different DER technologies at the household level (for example, a combination of active demand response, rooftop solar PV, heat or electricity storage, and the family EV), the aggregation of several DER units of one kind (for example, a fleet of EVs), or the aggregation of several resources connected to a number of agents in different locations (such as a portfolio of loads of several types, a fleet of EVs and some local storage).

Key for the competitiveness of DER is the fact that, once aggregated, local management and control can make better use of the existing local synergies, and use resources closer to the existing generation, consumption and network constraints. The magnitude of these potential competitive advantages vis-à-vis power coming from upstream sources still remains to be proven. It is outside of the scope of this paper to present an in-depth elaboration on possible resulting new business models; nonetheless, we find several reasons to suggest that aggregation and hierarchical control might have sizeable advantages over the centralization of sources at the bulk level, and will thus inevitably leave margins for new businesses related to DER. At least three reasons speak in favor of aggregating local energy resources:

1. Aggregation can reduce the risk for each individual DER of not meeting its market commitments. For instance, where network tariffs for end consumers include a capacity component linked to a maximum instantaneous consumption limit, it can be profitable to aggregate a group of consumers to take advantage of the fact that not all of them will demand their maximum at the same time.
2. Aggregation can decrease potential costs arising from not meeting market commitments, especially when balancing markets lack liquidity. If markets were perfectly competitive, it would always be possible to buy or sell the commodity at the competitive market price. But in case of low market liquidity, individual DER units risk having to buy costly services from dominant actors in the market, in order to correct for imbalances. In such a setting, holding, for instance, a portfolio of a storage facility and an intermittent generation unit could decrease imbalance costs.
3. Furthermore, aggregating otherwise relatively inflexible DER units into one DER product bundle increases the possibility of taking part in the markets for system services. Aggregated DER can offer more complete and flexible products to system operators, who often demand system services (such as for voltage or frequency adjustments, or for congestion management) with particular technical features. Aggregated DER are also easier to manage by system operators, compared to a multitude of agents offering a variety of services.

Ultimately, whether business models for (aggregated) local resources might – or might not – cause a paradigm shift from the traditional centralized top–down system towards decentralized local sub-systems depends on the total costs of energy provision from DER compared to upstream sources, including the network costs. As mentioned earlier, the substantially increased market penetration of DER has mostly been due to many low-carbon energy policies at EU and Member State level. Hence, the degree to which these local resources will further change today’s power systems not only depends on the competitiveness of DER relative to upstream sources, but also on whether policies for low-carbon power generation and consumption will continue to attract high investments in DER.

2.2. Distributed energy resources challenge existing DSO regulation

The more DER and resulting business models penetrate electricity markets, the more challenging it becomes for DSOs to pursue all tasks that they are assigned to by regulation. As DSOs are regulated entities, these challenges hold equally for regulators when designing proper incentive structures and assigned tasks for DSOs.

First, challenges relate to incentive structures for already existing tasks, mainly concerning the DSO as a regulated network manager: A high penetration of DER results in an increasing volatility of flows in local grids, and in an increasing uncertainty about net demand in distribution systems. Less demand is met by upstream generation, and more demand is satisfied by (often intermittent) local energy sources. Local supply exceeding local demand can even lead to reverse flows from the distribution system into higher network layers. As a consequence of uncertain power flows, plus potentially higher energy losses with a high penetration of DER, DSOs face increasing costs in developing and balancing their networks. At the same time, DSOs can also profit from employing local energy resources in their daily tasks of ensuring system functioning, for instance by using certain DER units to level out imbalances other DER units might cause. Finally, all distribution costs have to be remunerated via network fees. Therefore, changing cost structures also urge DSOs and regulators to rethink the design of network charges.

Second, challenges pertain to properly aligning new tasks that arise with the integration of DER business models: According to EU legislation in Directive 2009/72/EC, DSOs shall provide a fair network- (and thus market-) entry for all grid users. Challenges in this respect arise mostly in adjusting a level playing-field for all resources, those connected to the distribution grid, and those providing energy from upstream transmission grids. In particular, in order to enable DER to compete with resources connected to the transmission grid, DSOs have to provide adequate conditions for network access and usage of new business models. In the future, DSOs might have to provide not only infrastructure for energy, but also, to a greater extent, related infrastructures (such as information communication technology (ICT) or EV solutions), in order to guarantee fair access for all potential grid users. In addition, as the set of tasks for DSOs expands, the border to transmission system operators has to be re-examined as well. Power flows managed at the distribution level should not conflict with the overall system planning at the transmission layer, and therefore the new DSO activities have to be aligned with existing TSO procedures.

Consequently, and as depicted in Fig. 1, existing regulation needs to be reviewed with respect to two key areas. On one hand, the incentives of DSOs for performing their traditional tasks as network operators have to be reviewed. In detail, this concerns their regulated remuneration as well as the tariff structures with which the costs of DSOs are compensated. On the other hand, the set of tasks for DSOs as key players along the supply chain has to be examined; more specifically, this relates to the DSOs' role when becoming active system managers.

3. Existing regulation of DSOs needs to be reviewed in its full spectrum

As pointed out in Section 2, existing regulation needs to be reviewed in its full spectrum by considering electricity DSOs as regulated network operators, but also as key players along the supply chain, who interact with the transmission system operator, and with commercial market players. In the following, we use this distinction to propose the required adjustments to DSO regulation, prior to, in Section 4, discussing the implementation possibilities of different measures at the EU and Member State levels.

3.1. The DSO as a regulated network operator

The fact that the regulation of electricity DSOs has to be reviewed is widely recognized (e.g., de Joode et al., 2009; Benedettini and Pontoni, 2012; Agrell et al., 2013). Adjustments in incentive structures for DSOs to engage in their traditional task of operating local electricity grids concern the regulated allowed remuneration of DSOs. Adjustments in incentive structures for grid users concern distribution network tariff design.

3.1.1. Allowed remuneration of DSOs

For high amounts of DER connected to distribution systems, the total costs of business-as-usual management of distribution networks (that is, a continued "fit-and-forget" grid management) is likely to increase in most systems. Substantial future investments are required to properly connect all DER units to the distribution networks in order to allow the system to deal with increased volatility of net-demand and peak-demand fluctuations, as well as to set up ICT infrastructure that empowers DSOs to employ DER for their daily grid operations. However, at the same time, DER, offer a new set of instruments for grid operation, and thereby a tool for DSOs to perform their tasks of ensuring reliable, secure, and efficient electricity distribution. DER allow for active distribution system management, and have the potential to decrease the total costs of DSOs, compared to not relying on DER in local system management.

In terms of operating and capital expenditures (OPEX and CAPEX), the use of DER in distribution grid management can decrease OPEX compared to business-as-usual; for instance, when contracting system services from competing DER, instead of relying on more expensive, traditional solutions for voltage control and loss compensation. In contrast, how the use of DER will impact CAPEX is not obvious. Using DER for grid operation can decrease

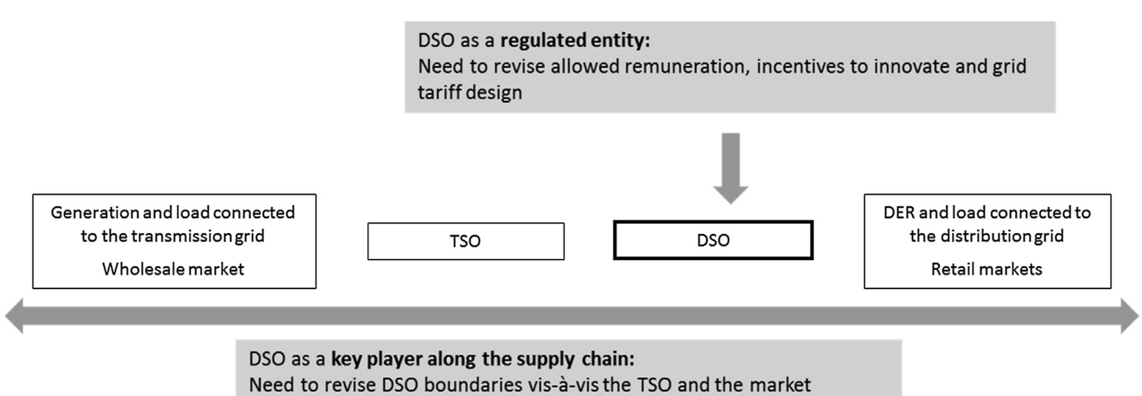

Fig. 1. Relevant areas of regulation.
Source: Own depiction.

CAPEX in the long run if grid investments can be deferred. For instance, using local resources to solve local congestion can postpone – and might even avoid – investments in new lines (CAPEX hence being substituted by OPEX).[1] On the other hand, in the short run, significant expenditures for investments into grids and ICT infrastructures that support grid monitoring and automation are needed. New types of assets as part of the smart grid infrastructure will, therefore, also reflect on new types of CAPEX.

The fact that employing DER can lead to overall cost savings for DSOs compared to the traditional "copper and iron strategy" (Merkel, 2013) has also been confirmed by Yap (2012), as well as Cossent et al. (2010),[2] who estimated non-negligible cost savings from using an active system management approach for rural, suburban and urban areas in the Netherlands, Germany and Spain, especially for increasing DG shares. In a similar vein Mateo and Frías (2011) and Pieltain Fernandez et al. (2011) argued that unless DSOs control electric vehicle charging within an active system management approach, huge investments into low- and medium-voltage lines would be required to compensate for local peak demand resulting from EVs. This example from EVs clearly demonstrates the trade-off between CAPEX and OPEX, and the resulting potential to avoid unnecessary costs for DSOs.

To sum up, there are two regulatory mandates. First, regulation has to account for the increasing total cost of distribution, considering not only grid reinforcement but also possibly increasing losses and investments into related infrastructures. Second, regulation has to concurrently incentivize an active system management in order to cushion these costs.[3] Thus, sound regulation has to account for (a) changing OPEX and CAPEX structures, including also new types of assets and respective CAPEX categories, (b) the optimal choice among the latter; that is, how DSOs can be incentivized to find the optimal trade-off between using DER and upgrading (or building new) lines, and (c) how to incentivize DSOs to deploy innovative solutions and operating procedures.

If negotiating and benchmarking CAPEX and OPEX becomes too complex due to new types of costs (ICT infrastructure, new platforms to procure system services, etc.), regulatory authorities have to increasingly rely on engineering estimates of expected costs. Traditional models are no longer suitable, and new types of engineering models are needed. However, they require a significant amount of effort to be built as they incorporate the essential technical features of distribution networks and DER connection. For example, such "reference network models" are applied in Spain (Mateo et al., 2011; Gómez et al., 2013).

Regardless of which regulatory mechanism is chosen, there are general improvements that can incentivize required future investments within each regulatory framework. These include a prolongation of regulatory periods, a higher focus on measurable output definitions and on corresponding DSO performance indicators, through which DSOs are compensated for a higher DER penetration in their grids, and for the implementation of innovative projects.[4] The focus of regulation has to shift from achieving operating efficiency gains towards facilitating the achievement of environmental and supply security objectives (see also Eurelectric, 2010a).

3.1.2. Distribution network tariff design

The allowed remuneration discussed above materializes in the form and level of distribution network tariffs. Rodríguez-Ortega et al. (2008) have already pointed out that "a higher degree of efficiency will be reached not only by introducing competition in generation and retailing activities, but also by designing […] distribution tariffs that send sound economic signals." A satisfactory tariff design is essential to both promote optimal short-term system usage of the grid, and guide efficient long-term development.

The present design of network tariffs does not provide a level-playing field among all agents that use the distribution network. With an increasing penetration of DER, ill-designed distribution network charges, such as volumetric tariffs combined with net-metering, will become even more problematic. Business models exploiting inefficient arbitrage possibilities caused by differentiated treatments of different DER technologies, or of certain types of producers and consumers, might flourish in the absence of sound tarification procedures. Moreover, grid users are becoming complex, sophisticated agents, which can have very diverse consumption and production patterns, being able (and willing) to react to price signals.

These facts demand an immediate overhaul of the current paradigm of network tariff design. The current paradigm, which was exclusively designed for pure consuming agents, and where distributed generation was considered a minor exception, no longer holds. The power system of the future (and, in fact, of the present in many countries) will be much more complex, and the tariff design paradigm has to be changed immediately before much efficiency distortion is created, and many agents acquire rights to ill-designed subsidies. A continuation of traditional tariff design methodologies applying widely uniform charges over the whole distribution system, and, thus, socializing network cost among all "consumers," would imply increasing cross-subsidization. This practice clearly goes against the principles of cost-causality and economic efficiency, and would create all sorts of perverse incentives within the tariff system.

Instead, grid tariffs, on top of guaranteeing full cost recovery, should be able to convey efficient economic signals to the entire diversity of agents that may connect to the distribution grid. Any hidden subsidies should be removed and replaced by sufficient, but direct, subsidies that do not turn into inefficient signals. Tariffs

[1] Quantitative evidence already exists for the integration of distributed generation. Power injection from DG changes flow patterns, which modifies energy losses. This effect can be either positive or negative, depending on a number of parameters such as the DG penetration level, concentration and location of DG units within the system, or specific DG technologies deployed (see, e.g., Yap, 2012; González-Longatt, 2007; DG GRID, 2006). In turn, the need for grid reinforcements will strongly depend on the system management approach. DG GRID (2006) illustrated substantial benefits from active network management for different levels of DG penetration and concentration. For the UK distribution system, for instance, up to 50 percent (15–40 percent) of the cost of upgrading the system could be saved for an installed capacity of 5 GW (10 GW respectively).

[2] Even though the cost reductions from active system-management might not be significant for all systems (especially in those where peak demand remains unchanged, or even increases with a higher penetration of EVs, and thus the DSO cannot avoid building new lines).

[3] Various forms of cooperation among DSOs and ICT companies could be considered. In a joint-venture model recently implemented by a Dutch DSO, the communication infrastructure for smart grids could become part of the smart grid infrastructure; that is, falling into the regulated domain. ICT companies provide their expertise in building and operating this new infrastructure; that is, generating revenue outside the regulated domain. However, merging distribution and data-infrastructure business models opens new regulatory concerns that cannot be elaborated in this paper.

[4] CEER (2011) discussed a number of (technology-neutral) indicators that can help to quantify the effects/benefits of grid "smartness." For instance, indicators of adequate grid capacity include the hosting capacity for DER in distribution grids (used in Italy as a revenue driver; minimum requirements in the UK and Norway), or the energy not withdrawn from RES due to congestion or security risks (used for monitoring in different member states). For instance, indicators of enhanced efficiency and better service may include grid-user satisfaction, the level of losses, the actual availability of network capacity with respect to its standard value, or the time to connect a new user.

should reflect the true costs (or benefits) of different types of load and generation for the system.

We shall assume an availability of detailed online information about the net demand minus generation profile of the agents, as provided by an advanced meter (if this is not the case, reasonable assumptions and simplifications will have to be made until universal hourly meters in the EU become a reality). Three cost drivers, depending on the geographic location in the distribution system, as well as on the profile of injection/withdrawal from the connection point, can be identified:

1. The existence of the agent (as well as of all other agents, which jointly require a minimum basic network to be connected to the grid) in a specific geographical location, and the grid user's *subscribed capacity*;
2. The grid user's *contribution to the local distribution peaks*, which have an impact on the design of the distribution network at all voltage levels. (Two kinds of peaks have to be considered, since a feeder can either be in import or export mode. A grid user can then either help the system at coincidental peak times – for example by injecting power when there is excess demand – or, in contrast, may worsen the situation – such as by injecting power when there is excess supply, or having net consumption when there is excess demand. Hence, the respective tariff component can be either positive or negative. This cost driver is expected to have the strongest impact on cost allocation, and it is the one that will vary drastically with the nature and behavior of the agents connected to the grid.);
3. The grid user's *aggregated contribution to losses* based on their (yearly) profile. Optimal reduction of total network losses with appropriate network reinforcements also has an impact on network design.

A network reference model (as briefly described above) and presented in depth by Gómez et al. (2013) can be very useful to evaluate these three components of distribution network charges, and how the costs to be allocated to the agents depend on the characteristics of the driving factors; that is, location and profile.

Signals need to be efficient and predictable. This implies that a sound methodology should be implemented that respects, as far as possible, the principle of cost-causality. Since agents connected to the distribution grid can change their usage pattern in the mid-term (imagine, for instance, a prosumer, who consumes most of their electricity during morning and evening peak hours, and injects power from rooftop solar PV during off-peak midday hours, and decides to invest in energy storage capacity), the charges associated with a grid user's contribution to the local peaks need to be adapted closer to real-time (for example, monthly). In contrast, charges reflecting a grid user's aggregated contribution to losses could be computed and charged over a longer-term horizon, since it is the aggregated value of losses over a long period of time that has an impact on network design. Therefore, this charge can depend on the yearly net-consumption profile.

Admittedly, the proposed reference framework for the design of electricity distribution grid tariffs involves many complexities, and the calculation of individual tariffs for each grid user would not only involve extremely high computation efforts, but would also result in tariffs perceived as difficult to understand and implement. Applied to real-world settings, therefore, a transparent, sufficiently simple and implementable methodology could consider a number of zones within the distribution system (those predominantly importing power, exporting power or neutral), and a number of types of agents connected to it, which correspond to some sort of classification of types of profiles. When distribution costs are allocated to those who cause them – admittedly not a simple task – distribution tariffs will induce a more efficient behavior of grid users.

This general approach has to be made compatible with some practical and legal matters, and also has to be put into the perspective of overall market design. For instance, considerations might include how to make compatible the political choice of a "single socialized tariff" for residential consumers in many European countries with the multiplicity of tariffs that will be needed to deal with the diversity of profiles of the agents; or which treatment to apply to any agent, or group of agents, that decide to function in partial or total independence from the grid (such as using autonomous micro-grids), but who were responsible for the network development to supply them in the past.

The proposed reference framework has not addressed the resolution of network constraints that may require the curtailment of generation or demand at the distribution level. This is a short-term issue that must be dealt with separately from the design of tariffs to recover the costs of the distribution network. Situations of critical network congestion should be addressed by demand and local generation response programs (that offer remuneration for a certain demand reduction or extra production in a certain period of time and at a specific location), or by emergency curtailments.

3.2. The DSO as a key player along the supply chain

The more DER can compete with upstream sources, the more important DSOs become as key players along the supply chain; accordingly, the set of DSO tasks in this supply chain has to be reviewed. New tasks may be assigned to DSOs, of which some concern DSO interaction with market players, and others DSO interaction with their respective transmission system operator.

3.2.1. DSO activities vis-à-vis the TSO

Today, DSOs mainly ensure system reliability along three major lines of tasks: network investments, maintenance and reinforcement, voltage control, and load/generation curtailment. While the first implies the provision of a grid infrastructure, both latter tasks concern the operation of the grid. Voltage control helps to keep adequate levels of quality of supply. Via load curtailment in the case of local congestion, DSOs can handle emergency situations. Hence, to date, DSO network management has been mainly based on acting directly on the networks, for example by changing the load flows, or trying to deviate the potential surcharges through alternative circuits. It has not included managing loads, except in cases of emergency events, in which DSOs guide their operation decisions by security protocols that in principle are agreed with the regulator, or at least are subject to *ex-post* supervision. Instead, TSOs pursue tasks that, besides long-term grid planning, are more directly related to balancing the network, and hence relate to short-run supply security.

When moving from "passive distribution networks" towards an "active distribution system management," DSOs increasingly become active system operators, and the existing hosting capacity of the distribution network can be used more efficiently if an optimal use of distributed energy resources is considered. Thus, DSOs become agents that manage local markets for network services, or directly purchase services with commercial value. Subsequently, their role and organization acquires an important impact on market functioning. Thereby, the general responsibilities of network operators with respect to grid management do not change, but the set of tools available to perform their tasks is enriched by DER. DER can offer a range of products by which to manage short-term problems in the grid, to optimize the cost of maintaining the desired quality of service, to reduce grid losses, and to reduce or postpone future grid investment needs.

Some of the products DER can offer are clearly relevant for either the transmission or the distribution system operator, whereas other types of services might be of interest for both. Hence, a clear hierarchy of functions between TSOs and DSOs has to be established. Coordination, from the planning stage to operation, as well as information exchange, will play a particular role as the amount of DER increases. The TSO is the party that is responsible for system balancing. This notion implies that DSOs, after having undertaken their DER-related activities, submit their protocols to the TSO, who is the final responsible system operator regarding the transmission level. Clear protocols have to be defined regarding which resource has sold products already, to whom, and for what timeframe, as well as priorities in case of conflict.

Furthermore, products that DSOs and TSOs use to ensure reliable grids (and often procure for this reason) should be clearly defined. Besides technical differentiations, products with economic value to system operators can be differentiated by region (products can be location-specific or system-wide), as well as by their time of delivery. Wherever DSOs and TSOs can procure the same service in principle, the more coordination among them is needed, and the more this product relates to real-time trading. In turn, the more products become used in real-time, the more they have system security character, and subsequently have to be procured and used by the entity that is eventually responsible for maintaining short-run supply security.

In general, there is no need to modify the TSO balancing market. However, an efficient market functioning is key and any barriers (for certain groups of agents, such as DER, or aggregators thereof) to participate in these markets should be removed. With respect to the use of DER for local feed-in and curtailment management, for example, rules are either completely missing (as in Austria), are only determined at the TSO level (as in Spain or Italy), or are defined at both the TSO and DSO level (as in Germany) (see Eurelectric, 2012 for more details). The regulatory aim should be to allow DER to compete on equal terms with the agents that currently provide system services.

In this vein, the Energy Efficiency Directive (Directive 2012/27/EC), which demands that system operators, in meeting requirements for balancing and ancillary services, shall “treat demand response providers, including aggregators in a non-discriminatory manner, on the basis of their technical capabilities”, goes in the right direction. Moreover, as discussed in-depth elsewhere, it is necessary to improve market price signals and adjust regulatory incentives to better reflect – that is, recognize and remunerate – the value that flexibility resources can provide to the system.[5]

Nonetheless, even if products for system services are well defined, as discussed above, some resources could offer their services to both DSO and TSO. Battle and Rivier (2012) discussed examples of such operations. The DSO could either procure services to solely satisfy its own needs, or procure services on behalf of the TSO as well; alternatively, there could be a situation in which both system operators engage in simultaneous procurement. Note that, especially for the first two options, the procurement procedures differ. If, as the authors discuss, the DSO only procures according to its own needs, say capacity to limit demand in one of its several distribution areas, the procurement procedure would only invite bids from that distribution area. However, if the DSO would also procure additional resources for the TSO, the DSO could accept bids from several, or all, of its distribution areas. In this way, the DSO can find the cheapest resources within a larger geographical area, and, if resources are not needed, pass on to the TSO (without acting commercially; that is, without changing the terms of the initial bid submitted by the DER or aggregator). This example already suggests that, even with the efficient design of services, an enhanced coordination among DSOs and TSOs will be needed.

Eventually, coordination needs differ among systems. Differences arise in terms of whether a distribution system contains only an insignificant amount of local resources, whether, in contrast, there is a large penetration of distributed generation with installed capacities that considerably exceed peak demand, or whether it even contains a whole portfolio of DER, including non-negligible volumes of local storage that demand response potential. Moreover, coordination efforts will also depend on which voltage levels are part of the distribution activity, and will probably have to increase when DSOs also operate MV (or even HV) grids.

3.2.2. DSO activities vis-à-vis the market

There are a number of areas in the newly emerging market environment where there is no consensus about whether the respective tasks should be under the responsibility of the DSO or not. For example, these tasks include the ownership and management of advanced metering equipment or data handling. In theory, these tasks may be fulfilled by regulated agents (which could be the DSO, or also a third regulated entity) or may be opened for competition. Thus, the regulatory challenge is to clearly define the roles, boundaries and responsibilities of DSOs, so that there is a level playing field for all potential and valuable business models.

Different proposed (and partly also already implemented) regulated, as well as liberalized, models for the ownership and management of metering equipment (Batlle and Rodilla, 2009; Schächtele and Uhlenbrock, 2011), data handling (European Commission (EC), 2013), or electric vehicle charging infrastructure (Eurelectric, 2010b) all have their advantages and disadvantages. For instance, there will be doubts about non-discriminatory, neutral market facilitation in case of insufficiently unbundled grid operators. On the other hand, the possibility to socialize costs can help to roll out a new infrastructure. Competitive pressure is conducive to achieving efficient solutions and innovation dynamics. In addition, certain models may benefit from scale/scope economies, or, in contrast, may suffer from difficulties related to their implementation and high regulatory efforts.

As a consequence, new tasks may or may not be offered at the lowest cost (due to sufficient synergies with grid operation), or, in a more qualitative way, by the DSOs, as compared to third regulated entities or commercial actors. The suitability of a certain model will depend on system-specific conditions, such as scale- and scope-economy potentials, the degree of uncertainty regarding the best technological solutions, or concerns with respect to possible market-entry barriers. However, if a full roll out of a new infrastructure, such as advanced meters, must be provided in a timely fashion, advantages lie in the domain of the DSO. As long as market structures are still evolving, commercial actors might shy away from investing. In contrast, cost recovery via the socialization of costs among grid users can jump-start new markets. However, regulators have to take care not to foreclose market structures through DSOs becoming incumbents once new technologies are deployed at scale, and commercial actors want to enter the market.

For all new infrastructure services, it holds that when regulators opt to implement these new tasks via DSOs, possible repercussions on energy and power markets cannot be ruled out. Retail market

[5] Ruester et al. (2012) also argued that balancing market rules should be modified, such that they relax minimum bidding requirements and rules requiring symmetric up- and downward bids in order to avoid impeding market access for small, decentralized agents. This will allow DER to value services they can technically provide, and thus will probably also have a positive impact on market liquidity. For the provision of ancillary services, replacing bilateral contracts with competitive tendering, wherever possible, could help to reveal and quantify the value of alternative flexibility means.

competition and, in particular, the current levels of unbundling, are not fully satisfactory.[6] However, insufficient unbundling is a major barrier to retail competition, given that DSOs shall act as "entry gates to retail markets […] making them an important influence on the level of competition as well" (CEER, 2013) (p. 8). Network access is essential for firms competing in downstream markets. European policy makers have opted for legal unbundling of distribution system operators that is, a compromise between allowing vertical integration, and requiring full ownership-unbundling. Not all Member States have fully implemented the 3rd Package, and not all countries have transposed the formulated requirements in the EU Directives to the same extent within national laws. For instance, rebranding[7] is not required to comply with the 3rd Package in all countries.

Negative effects of insufficient unbundling are also widely recognized in the literature. For instance, Nikogosian and Veith (2011) found significantly lower prices in markets with fully separated firms, compared to markets with vertically integrated or legally unbundled operators. For the UK distribution system, Davies and Waddams (2007) found "clear evidence that those incumbent electricity suppliers which remained vertically integrated […] have retained a higher market share than those where these functions have been undertaken by separately owned companies."

Ownership unbundling – that is, the vertical disintegration of distribution grids from generation and retail – is, to date, only required by law in two countries (New Zealand and the Netherlands, implemented in 1998 and 2011, respectively).[8] On a voluntary basis it is also present in the UK, where some ownership separation between distribution grids and retail activities has taken place over the last decade. In theory, perfect legal unbundling could also achieve the full separation of interests. However, as discussed in-depth in Nikogosian and Veith (2011) and Höffler and Kranz (2011), due to information asymmetries between regulatory agency and regulated firms, non-tariff discrimination remains an issue even if access prices are regulated for the upstream monopoly.

Harmful practices that can prevent the retail market from successfully developing are manifold. Such practices might include: an asymmetry in access to commercial information or grid access discrimination, giving the retailer belonging to the same group as the distributor an advantage; that is, the (illegal) use of references to the distributor's services in the retailer's commercial advertising; a lack of adequate procedures to switch supplier, and undue delays; and discriminatory practices, including excessive rates, in relation with the rental, installation and maintenance of metering equipment, if this is the responsibility of the distribution company.

With an increasing penetration of DER, and the accompanying advent of new market actors and business relations, the negative effects of limited unbundling become aggravated. When mandatory ownership unbundling is politically not enforceable, or is economically counterproductive for the customers' choice (through a drastic reduction of suppliers on the market) or for the customers' bill (through the duplication of costs in separated entities, the loss of synergy with other local utility functions, or the double marginalization in case of imperfectly regulated successive monopolies), stricter implementation of unbundling requirements, and market transparency measures, should be mandated as more responsibilities are given to DSOs. At the same time, it has to be noted that, before investigating new forms of "Chinese walls," the implementation of, and compliance with, existing unbundling requirements have to be reinforced.

Hence, the existing unbundling rules place minimum requirements on DSOs, on top of which additional requirements, supervision and monitoring can gradually be added as the role of respective DSOs changes with an increasing penetration of DER into their system. These additional requirements could mostly focus on the use of customer data and transparency in the procurement of services for DSO system operation. For instance, switching procedures should include clear mechanisms for accessing commercial information. An appropriate data management procedure should guarantee the availability of information for all interested market players (including retailers, but also aggregators, etc.), to the extent allowed under data protection legislation. With regard to the procurement of DSO services, market transparency could be facilitated by obliging DSOs to publish *ex-post*, procurement-related data. Strict supervision by regulatory agencies is necessary to prevent potential irregular practices, and to provide advice on the appropriate package of measures to be finally adopted.

We should also discuss whether *small DSOs* that want to engage in additional tasks, as introduced above, but which are currently exempted from unbundling requirements (according to Art. 26 of Directive 2009/72/EC), should also be exempted from additional "Chinese walls" that come with these new tasks. On this level, EU and national regulation will have a very high impact on local governance and municipal structures, in which a part of the profits from distribution activities are often also used for municipal social activities. Nonetheless, all problems arising from unbundling that are extensively discussed above likewise apply to small DSOs. If general exemptions from unbundling for small DSOs prevail, other regulatory means gain in importance. Therefore, especially for small, exempted DSOs, new ICT or EV infrastructure needs to be sufficiently standardized, such that third party market entry is facilitated as far as possible, despite the lack of unbundling. Furthermore, market data relevant to accessing this ICT infrastructure, and ultimately relevant for trading and retailing, has to be made available so that barriers to market entry are further reduced. Hence, the minimum requirements for data handling introduced above apply to small DSOs as well.

A further interesting regulatory option is to incentivize groups of small DSOs to jointly invest in ICT or EV infrastructure. Such joint ventures solve two problems. First, joint investments exploit synergies and reduce each DSO's contribution to the cost of setting up such new (and costly) infrastructure. Second, given that each DSO belongs to different companies with several respective affiliated retailing incumbents, negative effects from limited unbundling can be mitigated.

4. A role for the EU to encourage good regulatory practice

Due to the patchwork of many different distribution systems that exists throughout Member States, the role and possibilities of the EU in fostering a unique approach to future DSO regulation is also limited. With lesser amounts of distributed energy resources,

[6] Switching rates are still quite low. Estimates indicate that small-scale consumers EU-wide could save up to €13bn per year if they switched to the cheapest electricity tariff available (European Commission (EC), 2012b). However, it has to be noted that low levels of supplier switching are not necessarily an indicator of ineffective competition. In a mature market, prices will have converged already. Moreover, a lack of switching can also be explained by factors that are not price-related, such as customer satisfaction, trust in the incumbent supplier, or a lack of information.

[7] Rebranding: DSOs will be required to create their own image; that is, change their communications and branding in such a way that they can clearly be distinguished from their supply branch.

[8] However, Nillesen and Pollitt (2011), in investigating the impact of policy change in New Zealand, argued that ownership unbundling did not achieve its objectives of facilitating greater retail competition. In this case, one form of vertical integration (retail distribution) was swapped for another (retail generation). The authors found evidence that pure stand-alone retail companies are unlikely to survive in competitive electricity markets, given the volatility of wholesale markets. Thus, structural remedies may have unforeseen and irreversible consequences.

DSO cost structures are, to a lesser extent, subject to change; accordingly, the need to adjust the tariff design is decreased.

Furthermore, it will make a difference whether the respective DSO is subject to (voluntary) ownership unbundling, as it is the case in the Netherlands, or whether, in contrast, it is a small, integrated operator that is exempted from any unbundling provisions. This is the often case, for instance, for small German (*Stadtwerke*) or Spanish (*Cooperativas*) utilities, which also engage in non-energy-related social activities. Such activities are difficult to measure in terms of the benefits they bring to customers of DSOs, and hence are difficult to subsume within any regulatory framework.

For these reasons, a strong common European approach to future DSO regulation is not sustainable. European regulatory intervention has to be kept at a minimum level, thereby respecting the principle of subsidiarity. We see neither justification for, nor even potential convenience in, an EU-wide harmonization of DSO regulation, although we recommend setting clear minimum requirements in a few key regulatory aspects, as well as the publication of EU guidelines to spread, encourage and monitor good regulatory practices in some of the critical areas that have been identified in this paper.

- National regulators would benefit from sharing experiences on good and bad practices; for instance, for smart grid projects and their cost-benefit-analyses. EU guidelines for the sound regulation and adequate remuneration of DSOs should be formulated, and account for the increasing total cost of distribution, while incentivizing an active system management in order to cushion these costs. Regular monitoring and benchmarking will help to reveal shortcomings in national regulatory approaches. Similarly, although distribution grid tarification is – and should remain – a national issue, again, there is an urgent need for research to be conducted in order to develop a set of EU guidelines to be published and monitored.
- The performance of new business models, and the functioning of retail market competition, rely on comprehensive consumer data. The EU should provide a minimum level of support in this respect, and mandate that consumer data is made available to registered agents without any discrimination – provided that individual consumers give their authorization for the use of their personal profiles. Definition of the specific format of data provision (that is, one of the three data models proposed in (European Commission (EC), 2013), or a combination thereof) can then be left to the Member States.
- Depending on system complexity, and the number of tasks to be accomplished by DSOs, stricter unbundling requirements should be mandated. As system complexity increases, an insufficiently unbundled DSO could either stay with a restricted set of tasks, or the DSO could expand its portfolio of activities, while being accompanied with an increasing level of unbundling and supervision. The EU should provide guidelines for measures to reinforce "Chinese walls" between any DSO and the DER-related businesses that may exist under the same holding. If general exemptions from unbundling for small DSOs prevail, additional regulatory means, such as sufficient standardization of new ICT or EV infrastructures, will gain in importance.
- Finally, procedures and principles of coordination between DSOs and TSOs should also be defined at the European level, in order to avoid distortions in competition and barriers to market entry due to the existence of different rules and market designs in different Member States. The possible set of distribution company functions needs to be extended. The currently developed EU network codes should take into account the need for coordination and rules among system operators that rely on DER services.

5. Conclusion

The newly emerging broad range of distributed energy resources, be it distributed generation, local storage, electric vehicles or demand response, are driving changes in power systems. These changes pose challenges for DSOs and their regulation alike. This paper argues that, as a consequence, DSO regulation has to be reviewed in the full spectrum of DSO activities, and, more specifically, regarding both the traditional DSO tasks as a network operator, and the potentially new tasks of DSOs to integrate DER into retail markets, as well as distribution grid management.

First, remuneration schemes for DSOs need to be reconsidered. On the one hand, increasing amounts of DER require substantial investments: to properly connect all DER, to enable the system to deal with the increased volatility of net-demand and peak-demand fluctuations, and to set up ICT infrastructure that empowers DSOs to employ DER for their daily grid operations. On the other hand, DER offer a new set of instruments for grid operation, and have the potential to decrease the total costs of DSOs compared to the traditional fit-and-forget approach. Sound regulation that efficiently incentivizes DSOs to engage in active system management has to account for changing OPEX and CAPEX structures, to enable the optimal choice among both, and to incentivize DSOs to deploy innovative solutions.

Second, the network charges that allow DSOs to recover their costs are also subject to change. With an increasing penetration of DER and the likely creation of new business models at the distribution level, ill-designed distribution network charges will become even more problematic, resulting in increasing cross-subsidization and inefficient incentives. Therefore, tariffs should reflect the true costs (or benefits) of different types of load and generation for the distribution system, which will depend on the agent's geographic location in the system, as well as on the profile of injection/withdrawal from the connection point.

Third, there are a number of areas in the newly emerging market environment where there is no consensus about whether the respective tasks should be under the responsibility of the DSO or not. The regulatory challenge is to clearly define the roles, boundaries and responsibilities of DSOs. This depends on system complexity and the number of tasks to be accomplished by DSOs – stricter unbundling requirements should be mandated. Accordingly, as system complexity increases, an insufficiently unbundled DSO could either stay with a restricted set of tasks, or the DSO could expand its portfolio of activities, while being accompanied with an increasing level of unbundling. Increasing levels of unbundling could be implemented via higher "Chinese walls" between DSOs and their subsidiary retailers.

Fourth, the increasing amount of distributed energy resources and more active DSOs also establish a need for a clearly defined differentiation and cooperation of tasks between distribution and transmission system operators, via defining products that DSOs and TSOs use to ensure reliable grids in terms of geography and timing.

In the European context, regulation has to be kept at a minimum level, and respect the principle of subsidiarity. Accordingly, there is neither a need, nor a solid justification, for an EU-wide comprehensive harmonization of the regulation of DSOs. Instead, the EU should set certain minimum requirements in a few key regulatory aspects, and publish guidelines to encourage good regulatory practice. The decision on whether to include new tasks that foster DER integration into the DSOs' portfolios should be left to national authorities.

Acknowledgments

A research grant from the FP7 Programme (Research Project THINK) is gratefully acknowledged. While, as part of the THINK project, DG ENER provided helpful feedback, the views expressed here are solely those of the authors. We thank Jean-Michel Glachant, as well as three anonymous referees, for their helpful comments and suggestions. The usual disclaimer applies.

References

Agrell, P.J., Bogetoft, P., Mikkers, M., 2013. Smart-grid investments, regulation and organization. Energy Policy 52 (1), 656–666.

Batlle, C., Rivier, M., 2012. Redefining the New Role and Procedures of Power Network Operators for an Efficient Exploitation of Distributed Energy Resources. IIT working paper. Available at: www.iit.upcomillas.es/batlle/publications.

Batlle, C., Rodilla, P., 2009. Electricity demand response tools: current status and outstanding issues. Eur. Rev. Energy Mark. 3 (2), 1–27.

Beaudin, M., Zareipour, H., Schellenberglabe, A., Rosehart, W., 2010. Energy storage for mitigating the variability of renewable electricity sources: an updated review. Energy Sustain. Dev. 14 (4), 302–314.

Benedettini, S., Pontoni, F., 2012. Electricity Distribution Investments: No Country for Old Rules? A Critical Overview of UK and Italian Regulations. IEFE working paper #50/2012.

CEER, 2011. Status Review of Regulatory Approaches to Smart Electricity Grids. CEER Report C11-EQS-45-04.

CEER, 2013. Status Review on the Transposition of Unbundling Requirements for DSOs and Closed Distribution System Operators. C12-UR-47-03.

Cossent, R., Olmos, L., Gomez, T., Mateo, C., Frias, P., 2010. Mitigating the impact of distributed generation on distribution network costs through advanced response options. In: IEEE, Energy Market 2010, 7th International Conference, 23-25 June 2010, Madrid.

Davies, S., Waddams, C., 2007. Does ownership unbundling matter? Evidence from UK energy markets. Interecon. – Rev. Eur. Econ. Policy 42 (6), 297–301.

de Joode, J., Jansen, J.C., van der Welle, A.J., Scheepers, M.J.J., 2009. Increasing penetration of renewable and distributed electricity generation and the need for different network regulation. Energy Policy 37 (8), 2907–2915.

DG GRID, 2006. Costs and Benefits of DG Connections to Grid System – Studies on the UK and Finnish Systems. Deliverable D8.

Eurelectric, 2010a. The Economic Regulation for European Distribution System Operators. Eurelectric Report.

Eurelectric, 2010b. Market Models for the Roll-out of Electric Vehicle Public Charging Infrastructure. Eurelectric concept paper.

Eurelectric, 2012. Active Distribution System Management – a Key Tool for the Smooth Integration of Distributed Generation. Eurelectric Discussion Paper.

Eurelectric, 2013. Active Distribution System Management – a Key Tool for the Smooth Integration of Distributed Generation. Eurelectric Discussion Paper.

European Commission (EC), 2009. Directive 2009/72/EC, "Concerning Common Rules for the Internal Market in Electricity.

European Commission (EC), 2012. Energy Markets in the European Union in 2011. SWD, p. 368.

European Commission (EC), 2012. COM 663/2012, "Making the Internal Energy Market Work.

European Commission (EC), 2013. Smart Grid Task Force, EG3, First Year Report: Options on Handling Smart Grids Data.

Gómez, T., Mateo, C., Sánchez, Á., Frías, P., Cossent, R., 2013. Reference network models: a computational tool for planning and designing large-scale smart electricity distribution grids. In: Khaitan, S.K., Gupta, A., Aluru, S., Gopalakrishnan, K. (Eds.), High-performance Computing in Power and Energy Systems. Springer Verlag, Heidelberg.

González-Longatt, F.M., 2007. Impact of distributed generation over power losses on distribution systems. In: Paper Presented at the 9th International Conference on Electrical Power Quality and Utilization, 9–11. October 2007, Barcelona.

Höffler, F., Kranz, S., 2011. Imperfect legal unbundling of monopolistic bottlenecks. J. Regul. Econ. 39 (1), 273–292.

Kampman, B., van Essen, H., Braat, W., Grünig, M., Kantamaneni, R., Gabel, E., 2011. Impact Analysis for Market Uptake Scenarios and Policy Implications. Report by CE Delft. ICF International and Ecologic.

Loisel, R., Pasaoglu, G., Thiel, C., 2013. Large-scale deployment of electric vehicles in Germany by 2030: an analysis of grid-to-vehicle and vehicle-to-grid concepts. Energy Policy 65, 432–443.

Mateo, C., Frías, P., 2011. Upgrades in the Distribution Network with High Penetration of EV: Recommendations Regarding the Best Planning Practices Combined with the Most Efficient Strategies for Charging EV to be Followed by the DSO. MERGE Project D 4.1.

Mateo, C., Gomez, T., Sanchez, A., Peco Gonzalez, J.P., Candela Martinez, A., 2011. A reference network model for large-scale distribution planning with automatic street map generation. Power Syst. IEEE Trans. 26 (1), 190–197.

Merkel, M., 2013. Exploring aspects of synergy in energy data management. In: Presentation at CEDEC Workshop on Smart Grids, Brussels, November 6, 2013.

Nikogosian, V., Veith, T., 2011. Vertical Integration, Separation and Non-price Discrimination: an Empirical Analysis of German Electricity Markets for Residential Customers. ZEW discussion paper No. 11–069.

Nillesen, P.H.L., Pollitt, M.G., 2011. Ownership unbundling in electricity distribution: empirical evidence from New Zealand. Revue Ind. Organ. 38 (1), 61–93.

Pérez-Arriaga, J.I., July 2013. Visions on global energy systems. Is distributed generation a true game changer? Enel Found. Q. Newsl. 1–3.

Pieltain Fernandez, L., Gomez, T., Cossent, R., Mateo Domingo, C., Frias, P., 2011. Assessment of the impact of plug-in electric vehicles on distribution networks. Power Syst. IEEE Trans. 26 (1), 206–213.

Rodríguez-Ortega, M.P., Pérez-Arriaga, J.I., Abbad, J.R., González, J.P., 2008. Distribution network tariffs: a closed question? Energy Policy 36 (5), 1712–1725.

Ruester, S., He, X., Chong, E., Vasconcelos, J., Glachant, J.-M., 2012. Electricity Storage: How to Facilitate its Deployment and Operation in the EU. THINK Report.

Ruester, S., He, X., Vasconcelos, J., 2013. Electricity storage: need for a particular EU policy to facilitate its deployment and operation? Eur. Energy J. 3 (2), 23–31.

Schächtele, J., Uhlenbrock, J., 2011. How to Regulate a Market-driven Rollout of Smart Meters? A Multi-sided Market Perspective. Working Paper.

Yap, X.L., 2012. A Model-based Approach to Regulating Electricity Distribution under New Operating Conditions (MIT MSc thesis). Engineering Systems Division.