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EU power sector market rules and policies to accelerate electric vehicle take-up while ensuring power system reliability

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Abstract

How and when plug-in electric vehicles (EVs) are recharged can dramatically affect the electric grid. As a result, regulation of the power sector could have a significant influence on the rate of EV rollout. This paper explores how regulation can be developed to minimise negative grid impacts, maximise grid benefits, and shrink the total ownership gap between EVs and internal combustion engine vehicles. The authors discuss EU power sector policies and market rules that can facilitate or promote EV rollout with a focus on the role and design of time-varying electricity pricing, adaptation of EU electricity market rules to enable demand response and properly value flexibility, and the character of regulation that will likely be needed to encourage distribution system operators (DSOs) to be effective contributing partners in advancing progress with the roll-out of EVs.

Keywords: electric vehicle, grid integration, electricity market design, demand response, distribution system operator

1 Introduction

Electric vehicles (EVs) pose both a risk to and an opportunity for the power system. The main risk is at the distribution level, as EVs can easily overburden local distribution grids even at low penetration levels [1]. Mass rollout of EVs could also potentially increase the total peak demand on the power system, both generation and transmission, and could increase the within-day swings between minimum and maximum demand. By controlling the charging of EVs combined with better and smarter management of the network, the risk of overloading local networks can be minimised as can the need for expensive grid expansion or reinforcement and for investments in increased resource flexibility.

The inherent flexibility of EVs with respect to how and when they are charged, however, is also potentially valuable to power system operators in order to maximise utilisation of the grid and low carbon variable energy resources while maintaining reliability. EVs could provide transmission system operators (TSOs) with the flexibility increasingly needed in all electricity markets: capacity, energy, balancing services and reserves (see Figure 1). At the distribution level, smart charging of EVs could assist distribution system operators (DSOs) with local balancing, congestion management, and power quality. Providing TSOs and DSOs with such services would not only facilitate rollout from a system-wide technical perspective but could also improve the economics of EV ownership. The extent to which this is possible will be highly dependent on the following three key areas of power sector regulation, framed in the context of European legislation driving toward full liberalisation and integration of electricity markets in parallel with decarbonisation of the power sector:

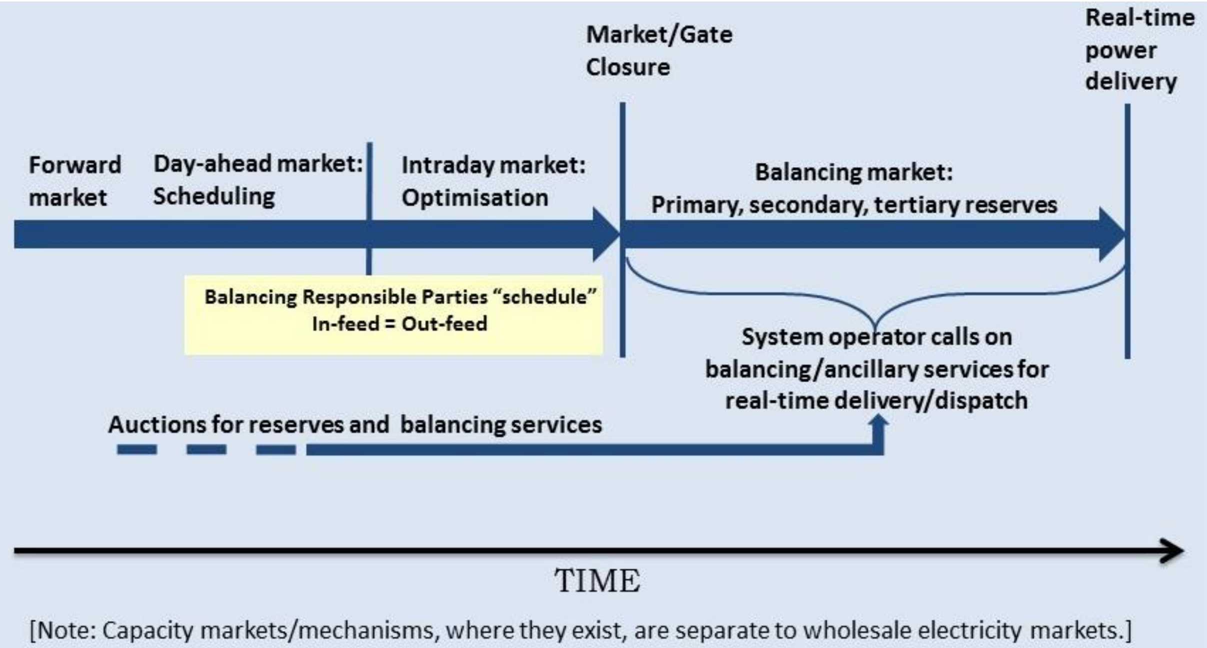


Figure1: EU wholesale electricity markets

1. Adaptation of market rules and regulation to ensure fair competition and in particular to enable the participation of aggregated demand response in all electricity markets;
2. The proper valuation of flexibility (both supply-side and demand-side flexibility) in electricity markets;
3. The regulation of distribution system operators (DSOs), including setting of revenues and the structure of grid tariff design for collection of DSO revenues and as a tool to influence EV charging behaviour.

2 How an EV is charged matters

How and when EVs are recharged can dramatically affect the electric grid in different ways. EVs offer the equivalent of a very flexible and dispatchable energy resource by offering a very flexible and dispatchable demand for energy. Charging can be controlled in order to both minimise negative grid impacts and provide valuable power system services, more specifically:

- When an EV is charged determines whether it coincides with the peak or valley of the load curve. Integrating off-peak charging generally requires fewer modifications to system capacity, and hence avoids costly capacity expansion, because the system is already built to handle load increases up to the projected peak.
- How the EV charging impacts the supply curve (merit order) determines the wholesale electricity price impact and the emissions from the added electric power generation.
- How fast an EV is charged — i.e., the capacity of the electric vehicle supply equipment (EVSE) — determines how much the EV increases the system load. Lower-capacity charging scenarios have smaller impacts on load.
- Where an EV is charged will have a bearing on the costs of EV and integration of variable renewable energy sources (RES) because the load curve, costs, and fuel mix are highly location-dependent.

The way that batteries are recharged can offer significant flexibility to the system. Although there are times when a fast charge is needed to continue a journey, most EV users require a known amount of charge during the day or overnight but may be indifferent to when, or at what rate, that charge occurs. Also, vehicles are available most of the time for recharging as they tend to be driven actively for less than two hours per day [2]. Recharging can be carried out at a constant, accelerating, or decelerating rate, with the possibility to repeatedly interrupt or restart recharging. Recharging can therefore be flexibly managed around the availability of variable RES and charging can be controlled to avoid overload of local transformers.

Compared with fast, high-capacity charging (i.e., International Electrotechnical Commission (IEC) Modes 3 and 4), low-capacity charging (i.e., IEC

Modes 1 and 2) does not need expensive charging equipment and presents a much lower risk for stressing the distribution system and greater opportunity to provide grid services to the system operator [3]. Unidirectional EV charging can offer grid services right away, even in the absence of smart interval meters in households, as the necessary information and communication technology (ICT) will be installed in the car and activated via the internet, and even if vehicle-to-grid discharge is not viable yet. The focus of this paper is therefore restricted to smart unidirectional charging (i.e. grid-to-vehicle (G2V)).

3 The power system's growing need for flexibility

European legislation is driving the penetration of renewable energy sources into the electricity system. In any realistic scenario including all EU Energy Roadmap 2050 scenarios [4], RES would increase substantially across the EU as a whole, achieving a minimum of 55% in gross final energy consumption by 2050 with a high share of this likely from variable RES. The growth in variable RES means that the daily net energy demand profile — total energy demand minus the available renewable energy from resources such as wind and solar — is becoming much more challenging to anticipate and balance over all timescales. Wind and solar energy are variable, as is demand, but their variability often not well correlated, as demand and variable RES can increase or decrease in opposite directions.

The power system therefore requires:

1. More responsiveness of energy demand to shortages or surpluses in supply; and
2. More flexibility in energy resources dispatched by the system operator.

The first requirement would involve EV charging responding to real-time prices in the energy and balancing services markets. Low prices would likely exist at time of high availability of variable RES and low demand while high prices would likely occur when the availability of variable RES is limited and demand is high. With growth in the share of variable RES in the power mix, this could constitute a major driver of smart charging services revenue models.

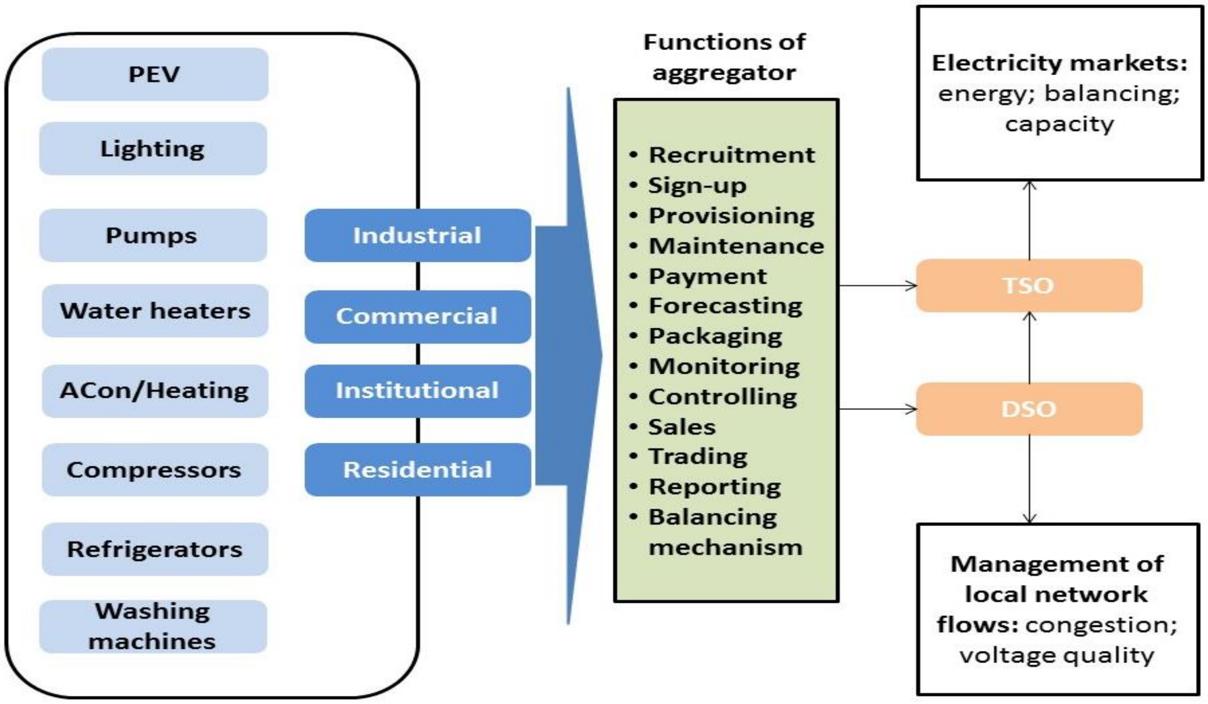
To satisfy the second requirement, energy resources dispatched by the system operator will need to have the capability to increase or decrease rates of energy supply and demand at steep gradients (ramping) and repeatedly over time (cycling), in order to "flex" around the availability of variable RES and the capabilities of other system resources. As the share of wind and photovoltaic generation in the power mix grows and replaces conventional thermal capacity, system *inertia* will also be reduced. As a consequence, some system operators are starting to define products with these flexible attribute and also very fast reserve requirements that can compensate for reduced system inertia [5].

A more flexible mix of dispatchable resources, capable of shifting operations up and down in synch with the less controllable shifts in variable renewable production, will have far higher asset utilisation rates and require far less redundancy than a less flexible mix of thermal resources. Energy resource adequacy and reliability of a power system is no longer solely a question of enough megawatts; it is also a question of the operational capabilities of these megawatts because this will determine the quantity needed and hence the resulting cost. Regulators will need to adapt market rules to take account of the changing operational requirements of the power system and to ensure flexibility is properly valued.

4 EV flexibility: Status of access to electricity markets

Demand response is defined as customer loads that can be modulated up or down in real time in response to wholesale market conditions, expressed either in wholesale prices, via frequency or voltage fluctuations, or through arrangements allowing direct control by the system operator or third party aggregator. While EVs can technically offer a highly flexible form of demand response and while growth in variable RES creates a growing need for flexibility in the system, the participation of demand response in EU power markets today is limited. Many market barriers to demand response, aggregation of load and new entrants need to be removed if the full potential of energy resources on the demand side, such as EVs, is to be exploited. Demand response participating in European electricity markets today is generally limited to infrequent use under extraordinary system stress conditions provided by large loads from the industrial or commercial sectors. This is a very different role to what will be required in future when net energy demand becomes much more variable with growth in variable RES.

That said, comparison with the United States (US) indicates that, even today, much potential for demand-side participation in EU electricity markets is not being tapped. A review of use of



Source: Adaption of SEDC graphic, p. 46 [7]

Figure2: The role of the aggregator

demand response in the electricity markets of the US concludes that the growth of demand response has been strongest where providers can develop confidence around what they are likely to earn and where multiple streams of revenue are present to support different types of load and different types of customer [6]. US regions that have not limited demand response services and that have allowed demand response to provide multiple types of services (energy, balancing, reserves, capacity) have demonstrated greater participation by demand response sources. Establishing clear, stream-lined and effective procedures for measurement of baselines and services delivered has also been critical to successful participation. Regulation at Federal level has also played a very important role.

4.1 Aggregation will be crucial to extracting value of EVs to the power system

If small consumers are to participate in electricity markets, their loads will need to be aggregated or pooled in order to reduce transaction costs, meet market or programme requirements, and reduce compliance risk [7]. Aggregators can also help consumers overcome the hassle factor, a major barrier to demand response, if they are allowed to act on behalf of the individual consumer and if aggregated loads are considered indivisible. An aggregator combines different energy resources from different sources and providers in order to act toward the DSOs and TSOs as one entity. To do this, the aggregator undertakes a number of functions, such as trading, load control and billing, as illustrated in Figure 2. In cases where the aggregator is not a supplier, the consumer would maintain a contract with the supplier.

The growth in the share of variable RES in the power mix will not only require energy resources with flexible capabilities but will also affect the volume of different types of services or reserves needed for balancing and backup. Studies show that growth in variable RES will only moderately increase the need for the faster primary reserves or frequency regulation [8]. Rather, the more significant system changes introduced by variable resources (particularly wind) tend to unfold over timescales of tens of minutes to hours, leading to a large increase in the need for slower-acting *secondary and tertiary reserves* (Figure 1) and increasing the incidence of large price swings in intra-day energy markets. Demand response that incorporates various forms of end-use energy storage, including EVs, can counteract large swings in net demand by responding to large intra-day price differentials. EVs could contribute very cost-effectively to meeting any increase in the demand for reserves if system operators would specify suitable shorter-duration products and adopt a "rolling" contract approach in which aggregators can switch loads (including those of short duration) in or out of their aggregated pool of energy resources. If such switching is possible, the larger the pool of aggregated demand, the easier it is for aggregators to provide demand-response services over longer time periods.

4.2 EU electricity markets are gradually being opened up to demand response and aggregation

Compared to the US, demand response is not well established in the EU. Market rules have generally been written with large centralised generation in mind and in many cases do not permit or make it difficult for aggregated energy demand to participate in electricity markets. Implementation of the Third Energy Package, which would open up the markets to new entrants (aggregators are likely to be new entrants) has been slow [9], and 15 of the EU27 countries still regulate retail electricity prices, which poses a major market barrier [10]. Further, the functioning of the wholesale electricity markets, including the balancing and reserve markets, is sub-optimal and the value of flexibility is not fully exposed. It is not within the scope of this paper to discuss here but a number of steps could be taken to improve the situation [8][11].

Building on the intention of the Third Energy package, Article 15.8 of the Efficiency Directive [12] sets down some specific requirements which will enable participation of energy demand and aggregation in wholesale (including balancing and reserves markets) and retail electricity markets alongside energy generation. The legislation specifies that DSOs and TSOs are to treat demand response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities. The article states that Member States are to define the technical details for participation in these markets based on the technical needs of these markets and taking into account the capabilities of demand-side energy resources. Some of these technical details are being defined in the EU Network Codes, to be discussed later in this paper, as required by the Third Energy Package.

In a review of progress on the implementation of Article 15.8 of the Energy Efficiency Directive (EED), the Smart Energy Demand Coalition (SEDC) concludes that there has been some progress between 2013 and 2014 based on an assessment of the countries' market rules and regulations against four key criteria: consumer access to markets; appropriate program requirements; measurement and verification; and finance and risk management [13]. The overall assessment, combining these criteria, concluded that demand response is only commercially active in a handful of countries: the United Kingdom, Ireland, Finland, France, Belgium and Switzerland. It is surprising that developments to open up markets to the demand side in Germany and Denmark, where there is a need for greater power system flexibility as the share of variable RES is relatively high, are only at an early stage. In some countries, notably Spain and Italy (where smart meters have been fully rolled out), markets are virtually closed to participation of demand response.

All products need to be defined in a way such that any energy resource technically capable of delivering the service can do so. Yet many of the market barriers identified by SEDC relate to unreasonable market or programme participation requirements as market rules restrict, or in some cases prohibit, aggregation of energy resources. High minimum bids exist across Europe. For example, until recently the minimum bid size in France was 50 MW to enter the frequency restoration reserves market. The bid size has been reduced to 10MW but this is in contrast to the minimum bid size of 0.1 MW applied by PJM, the US-based system operator. In some markets, the length of forward commitment and availability requirements may be imposed on individual energy resources, rather than the aggregate. Of particular relevance to EVs is that some markets prohibit asymmetric bids for regulation, but an EV's available capacity for upwards reserve (i.e., reducing load by decreasing the recharging rate) and downwards reserve (i.e., increasing load by increasing the recharging rate) may be very different. Unwarranted location restrictions that bear no relation to the value of services provided to the system could also artificially restrict effective use of EVs as a mobile energy resource.

Participation of demand response in capacity remuneration mechanisms/markets (CRM), where they exist, is also limited. For example, the CRM recently adopted in the UK does not treat supply and demand on a comparable basis [14].

4.3 Who has the right to an EV's flexibility?

The SEDC survey also disclosed that in many markets today, independent aggregators must ask the customer's energy supplier/retailer for permission to use the customer's load. This is problematic as: 1) the vehicle is mobile, and is not always connected to the same supplier or balancing area; 2) the supplier is potentially a direct competitor to the independent aggregator as it too could provide demand response services; and 3) the supplier is very often what is called the "balancing responsible party" (BRP), meaning that it is financially responsible for keeping its own position (i.e. sum of its injections, withdrawals and trades) balanced over a given timeframe and the consumer's energy demand will be part of the BRP's responsibilities. If a consumer provides demand response to another provider — often referred to as the balancing service provider (BSP), — the BRP risks being put out of balance, which could result in losses from energy purchases made during balancing or imbalance penalties imposed by the system operator. A supplier needs recompense for energy he has purchased up front and which the customer has now "sold on" to the aggregator and should not be unfairly liable for imbalance penalties should a consumer choose to sell his/her flexibility to another provider. The Electricity Balancing Code (EBC) could potentially address this.

In countries where demand response is well established, the SEDC found that national rules protect the retailer and BRP from unfair purchasing and balancing risk while ensuring consumers direct access to markets and service providers. For example, France recently updated its legislation to achieve this effect through introduction of the Nomes and Brottes laws [15].

Protection of the consumer's right to sell his/her flexibility also needs to be incorporated in regulation of the system operators. This is because price signals in wholesale electricity markets may not correlate with price signals reflecting local network conditions. For example, response to low wholesale electricity prices might cause congestion on local networks. The TSO and DSO may therefore end up competing to procure the same energy resources, DSOs may try to corner the market for DER to address local network needs and market players could play system operators against one another. The Florence School of Regulation analysed these issues and concluded that establishment of a clear hierarchy of functions between DSOs and TSOs may be necessary and that coordination between DSOs and TSOs may need to be defined at EU level in order to avoid distortions in competition and barriers to market entry [16]. These issues are also being closely examined by ACER [17], CEER [18], and the regulatory working group of the European Commission's Smart Grid Task Force [19].

4.4 Promotion of DR and aggregation through the EU Network Codes

Of the EU's ten Network Codes, the Demand Connection Code (DCC), the Electricity Balancing Code (EBC) and the Load Frequency and Reserves Code (LFC&RC) will make a significant contribution to implementation of EED Article 15.8. ENTSOE, the association representing national TSOs, is responsible for drafting the codes, but this must be done in accordance with ACER's Framework Guidelines. ACER also assesses the code for compliance with its guidelines before the code enters comitology, the process by which it will become EU law. Once adopted, a code should be implemented within two years.

Technical requirements set out in the DCC will be crucial to enabling widespread aggregation of loads, including EVs, and participation of the demand side in electricity markets. The code specifies technical requirements for transmission connected demand facilities, transmission connected distribution networks and users providing demand response in the provision and use of a wide range of services (e.g., reactive power, power quality, frequency control). The precise wording of the codes and their effective implementation will be crucial. Some requirements in the codes are non-exhaustive, meaning they must be dealt with on a case-by-case basis or defined at Member State level. This presents a risk of ineffective or variable implementation across Member States to the detriment of the code's original intention. Implementation guidelines, such as those issued by ENTSO-E for the DCC [20] may support implementation but effective market monitoring will be necessary.

This issue of too many requirements being left for Member States (or national TSOs) to determine was central to ACER's critique of ENTSOE's first draft of the EBC [21]. If developed in accordance with ACER's framework guidelines [22], the EBC would establish a common set of rights in terms of access to the balancing markets and in terms of remuneration, on a comparable basis for supply and demand resources. The code would also address some of the technical details necessary to implement these rights, such as: obligations (in particular in terms of balancing responsibility) for all types of market participants (generation and demand); the standardisation and harmonisation of key elements such as balancing products, balancing energy pricing and imbalance pricing; and the harmonised definition of roles and responsibilities of TSOs, BSPs and BRPs. In ACER's view, however, the draft code was inadequate as it was based on a voluntary approach and therefore unenforceable. Furthermore, ACER believed more could be done to enhance competition in balancing markets and facilitate participation of the demand side.

4.5 Regulators recognise more action needed to realise full potential of demand side flexibility

In the EU, there is growing recognition of the beneficial potential that demand side flexibility could deliver in future. The conclusions of ACER's Bridge 2025 consultation encompass a series of proposals with demand side participation and improved competition taking central stage. Of particular relevance to demand side flexibility are proposals to establish: a demand response framework for Europe; a road map aimed at competitive and innovative retail markets by 2025; and an action plan to identify and remove (regulatory, technical, legal or market-related) obstacles to the development of demand side response and to facilitate its deployment. ACER also intends to ensure that the market for new service providers is not foreclosed by incumbents and that the provision of flexible response by generators and consumers is on a non-discriminatory basis.

Demand side flexibility is also the topic of a report being authored by the regulatory working group of the European Commission's Smart Grid Task Force. This report, to be jointly authored by industry and national regulators (represented by The Council of European Regulators (CEER)), will put forward recommendations for market rules and DSO regulation and incentives before the end of 2014. The contribution of national regulators to this report will likely draw from CEER's recently published advice on market and regulatory arrangements to deliver demand side flexibility [18]. This advice proposes: that consumers and market participants have the necessary information and tools to adequately and effectively engage in the market; a market free from barriers that promotes equal access for all parties and new entrants, through interoperable standards and arrangements; and a regulatory framework that is flexible enough to adapt in an evolving market.

In addition, DG ENER of the European Commission conducted a consultation in the first quarter of 2014 on the functioning of the retail energy market and consumer participation. The results and next steps are yet to be published.

5 Regulatory reform of Distribution System Operators (DSOs)

5.1 The changing role and new business models of DSOs

Literature and commentary on the future role of the DSO sets out a vision that DSOs will in future act as neutral market facilitators, actively managing and applying new smart grid technologies, and the large quantities of data that comes with it, in a way that makes best use of existing infrastructure and available and distributed energy resources, including demand side consumption and storage [16][23][24]. It is recognised that DSOs could be very valuable partners in coordinating the deployment and integration of distributed energy resourses, including EVs. The transformative change that DSOs will need to undertake if they are to reform their business models in this way, however, requires major regulatory reform in relation to the definition of their role and relationships with other market actors, how their revenues are calculated and how these revenues are collected from customers.

New York state is one of the first jurisdictions around the world that is attempting to action the theoretical futuristic business model concept for DSOs described by thought leaders such as the Rocky Mountain Institute (RMI). At the heart of the State's "Reforming Energy Vision" strategy is the development of a "distributed system platform" (DSP) [25]. This platform will integrate distributed energy resources, including EVs, and provide an interface between the wholesale bulk power system and increasingly diverse retail markets. In Europe too, regulators are beginning to rethink how they regulate DSOs, but no one size will fit all and the regulator will need to focus on enabling any welfare-enhancing business models under any future market conditions [16].

In future, some of the balancing and ancillary services previously delivered by transmission-connected generation will be provided at distribution level through demand response and distributed generation. DSOs, suppliers and aggregators, will be required to "parcel up" local demand response and generation in order to provide these services to TSOs. In addition, DSOs will increasingly take on a "TSO-type" role for their distribution networks, using these services to manage local congestion and voltage quality. Suppliers and third-party aggregators will coordinate closely with customers, DSOs, and TSOs to extract the greatest value from markets or through contracts for their pooled resources, including EVs. As previously mentioned, there may indeed be times when a resource will be of use to both the TSO and DSO and this will call for greater TSO/DSO coordination.

As DSOs collect and manage much customer data relating to the network and customers, regulators will need to ensure that DSOs manage this data effectively and properly, making it available to market actors such as aggregators without discrimination and within clearly defined boundaries necessary to respect customer privacy rules and concerns. If this is not possible, set up of an independent data management body may be necessary.

Although unbundling of networks has been implemented across the EU27 as part of the Third Energy package legislation, full ownership unbundling has not been required and MS have tended to opt for legal unbundling of vertically integrated electricity companies. In addition, exemptions for small DSOs (less than 100,000 customers) commonly exist. A recent report by the Florence School of Regulation on DSO regulation concluded that stricter unbundling requirements should be mandated depending on system complexity and the number of tasks to be undertaken by the DSO [16]. When the system becomes more complex with integration of DER, including EVs, DSOs could either operate with a restricted set of tasks or could expand its portfolio of activities so long as accompanied with stricter unbundling requirements. Should exemptions for small DSOs continue, the authors suggest countering this with alternative regulatory measures such as further standardisation for new ICT and EV infrastructure and requirements for providing access to market data in order to better facilitate third party market entry.

ACER recently stated its intention to ensure DSOs do not operate in ways which foreclose or distort the potentially competitive market in flexibility services, including from the demand side [10]. Regulators, EU and national level, will need to closely monitor market behaviour using appropriate indicators and take action to ensure effective market competition.

5.2 The role of grid tariffs and retail pricing to control EV charging

Experience with charging of hybrid vehicles has proven that clustering is possible in distribution networks [26]. This risk varies substantially with local network conditions. Some Member States have relatively fragile distribution networks. Typically, distribution networks in northern and western regions of Europe are more robust than those in the southern and eastern regions [27]. It will be desirable to manage EV charging as soon as possible, but the level of sophistication and accuracy of this control will need to change over time with growth in EV uptake and depending on the state of the particular distribution circuit.

As illustrated in Figure 3, household electricity prices consist of four core cost components: energy, networks, levies (e.g., RES subsidies) and taxes (e.g., VAT). National governments or regulators determine the level of VAT, taxes, subsidies or levies (e.g. for RES). The only element that regulators or governments do not control, if compliant with internal energy market legislation, is the energy commodity component. This component can be high in countries with a large share of fossil fuel plant in the power mix (e.g., the UK), as such plant have high operating costs. By contrast, wind and solar generation have low operating costs, so the energy commodity component in the retail price in countries with a high share of RES will be relatively small, while the taxes/levies component, covering RES fixed costs, can be relatively larger. Given the generally large share of regulated cost in the electricity retail price, regulators can structure the network charges, levies and taxes in order to influence how and when users, including EV owners, use energy.

Although liberalisation has resulted in unbundling of infrastructure and establishment of competitive wholesale electricity and retail markets, many electricity suppliers/retailers have sister companies selling energy generation. So while retailers may be keen to attract consumers that will increase their energy demand through EV ownership or electrification of heating, they may not be so keen to encourage demand response beyond the purpose of optimising their own procured energy portfolio unless there is real competition from other providers such as independent aggregators.

VAT is already correlated to some extent to the availability of RES as it is a proportion of the cost of energy, so when wholesale electricity prices are high, VAT will be high and vice versa. Taxes/levies could also be structured to influence energy demand. For example, Agora suggests

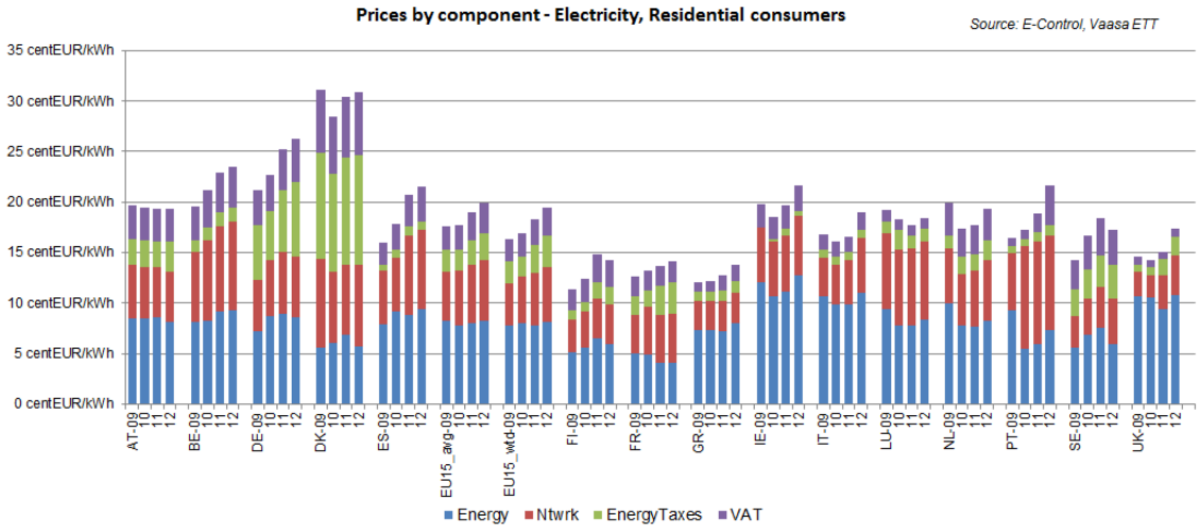


Figure3: 2008-2012 evolution of the retail price of electricity, median households by component [28]

linking the cost of Germany's RES levies (EEG) to the spot price, perhaps with a multiplier to strengthen the price signal [29]. This could encourage EV owners to charge when RES is available. A price signal reflecting the availability of RES across the whole balancing area, however, will not necessarily coincide with what might be happening on a local distribution circuit. To prevent overload of transformers at the local level, DSOs would need to use a more focussed tool for the problematic network area.

In accordance with the Electricity Directive (2009/72/EC), it is the responsibility of the national regulator to establish DSO revenues and rules for access to the network. Grid/network tariffs are used to collect the allowed revenues. In some countries the regulator sets the tariff structure, in others the DSOs can do this, although tariffs usually require approval by the regulator. DSOs have two key tools to influence energy demand: 1) grid tariff design; and 2) use of their allowed revenues to purchase targeted demand-side services for managing the distribution network e.g. congestion, voltage quality, deferred capital investment.

5.2.1 Grid tariff design to influence charging strategies

While there may be an opportunity to influence energy demand by communicating economic signals to consumers through grid tariff design, there are a number of well-accepted principles that should be adhered to in developing tariffs [30]. The most fundamental of these principles are sufficiency in cost recovery, economic efficiency and equity. Other principles that are relevant include efficiency, equity, sustainability, additivity, stability, transparency, consistency and simplicity. Very often, however, there are trade-offs to be managed and compromises are necessary. Tariffs will need to reflect forward-looking costs that end-users are causing and recover costs based on the character of cost causation while minimising cross-subsidisation and maximising wider societal welfare.

As part of a visioning process to explore how the DSO of the future might look, the RMI e-lab has developed a framework that is helpful for envisioning how grid tariffs could evolve [31]. RMI suggests that in order to evolve today's grid to a smart grid, able to maximise efficient use of infrastructure and available energy resources, regulators will need to incrementally increase the sophistication of tariff design for residential and small commercial (i.e., mass-market) customers along three continua:

1. ***Attribute unbundling***—shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services, and other components.
2. ***Temporal granularity***—shifting from flat or block rates to pricing structures that differentiate the time-based value of electricity generation and consumption (e.g., peak vs. off-peak, time-of-use pricing).
3. ***Locational granularity***—shifting from pricing that treats all customers equally regardless of their location on the distribution system to pricing that provides geographically differentiated incentives for distributed energy resources (e.g. nodal pricing, locational marginal pricing).

RMI suggests applying an approach whereby customers opt-in to more sophisticated tariffs and over time the opt-in tariff becomes default while a new, more sophisticated tariff is introduced as an opt-in choice. This approach gives customers time to adjust and helps protect vulnerable customers such as the elderly, small proprietorships who may find the introduction of more complex and dynamic tariffs beyond their ability to effectively manage. Evaluation of pilots undertaken by the Sacramento Municipal Utility District (SMUD), based in the US, demonstrates considerable customer responsiveness to more advanced tariffs employing response from a variety of loads, for both opt-in and default approaches [32].

In most cases, however, residential and small commercial customers are likely to have little interest in or tolerance for the increased complexity of either participating in such new tariff structures or determining the benefits they are likely to realize as a result. This implies a major role that commercial aggregators, which might include EV manufacturers as an example, can play in intermediating between customers and grid operators. The opportunity afforded by the more complex tariff designs suggested by RMI can be converted, for example, to a fee-for-service arrangement whereby the aggregator signs up a customer to provide a service such as smart-charging in return for a simple monthly fee paid to the customer by the aggregator. In this way, whilst the more engaged customer or customers with particular needs and special capabilities, such as EV owners, would likely be the "first mover" customers to opt-in for more sophisticated tariffs, the success of such programs in exploiting cost-effective opportunities at sufficient scale need not rely on an assumption that a substantial number of customers would have an appetite for the required level of engagement.

5.2.2 Grid tariffs in Europe today

In Europe today, grid tariffs are on the simple end of the attribute continuum and generally do not incorporate temporal or locational dimensions, though many demonstrations and studies are taking place in a number of Member States (e.g. see Table 1). Tariffs typically break down to a fixed monthly fee, a volumetric energy charge, and for some, a capacity- or demand-related charge based on the maximum load at the customer location. In Europe, some 50-70% [33] grid tariffs are based on the energy volume. While linkage to the energy volume does encourage energy efficient behaviour which will help reduce network losses, it is capacity that is the main cost driver of network investment and EVs can potentially add a significant load to peak capacity if charging is uncontrolled

The Energy Efficiency Directive (2012/27/EU) requires that network tariffs do not create a barrier to either energy efficiency or demand response. This suggests a two-part network tariff could be appropriate with a volumetric energy component promoting energy efficient behaviour and a capacity component encouraging demand response. Encouraging or applying capacity limits at the level of the small consumer, however, risks restrained and inefficient use of infrastructure and distributed energy resources as it is the total capacity at the level of the transformer and the circuit that serves the combined load of hundreds of consumers which is of relevance for the DSO. Depending on how the tariff is designed, consumers may end up paying penalties or suffer the inconvenience of circuits tripping when the household's capacity limit is reached even if the transformer and circuit have excess capacity at the time of charging.

5.2.3 Time-varying grid tariffs to control EV charging

A time-varying capacity component (kW) and/or a time-varying energy component (kWh), set ex-ante, could be more helpful in encouraging consumers to shift charging of EVs outside expensive peak times that are well known in advance. Dynamic pricing could be accommodated with more sophisticated in-vehicle charge controllers. There exists substantial evidence that the effectiveness of time-varying pricing considerably increases with automated control of the appliance (for an EV this would be through a smart charger or charge controller) and if rate differentials are relatively high [34]. People might be more responsive, however, to pricing for recharging of EVs compared to other household loads. Early results from the PEV Project in the United States suggest this is so, as customers in San Francisco and San Diego are responding strongly to time-of-use (TOU) rates based on energy volume throughput, whereas charging in Nashville, where incentives do not exist, is distributed much more evenly around the evening peak [35]. Evidence suggests fully engaging customers and enabling their effective response may be a greater hurdle and potentially more important than establishing a precise level of incentive [36]. TOU pricing schemes must be carefully designed,

Table1: Status of use of time-varying grid tariffs across Europe today [33]

Tariff category	Tariff type	Already existing	In demonstration	In study
Price-based (voluntary response)	Critical peak pricing		DK	CH,FR,NO,PT
	Dynamic pricing (e.g., real-time pricing)	DK	NL	CH, NO
Incentive-based	Interruptible tariffs	(CH, DE, ES, GR, NO, PT, SE)*	DK	BE, FR
	Direct load control	(CZ, DE, FI, FR, NO)*	DK	BE, CH

* Author's note: Usually as an overlay on top of regular grid tariff and applied to commerce & industry, not residential sector. Load is controlled by the system operator but may or may not participate in wholesale electricity markets.

implemented, and tested to assess how responsive EV owners will be and what the impact is likely to be on the grid [37].

Because TOU rates are set in advance for a fixed time period, an ex-post adjustment will be needed to ensure that the DSO collects its allowed revenues. Furthermore, ex-ante prices will not be as helpful in responding to unpredictable changes in system conditions, delivering the responsive load necessary for the integration requirements of variable renewable energy, or helping to avoid or ease real-time congestion on networks. TOU prices would need regular adjustment to have the desired effect, which could be a significant administrative burden for regulatory institutions. Some form of dynamic pricing capable of sending real-time price (RTP) signals has greater potential to shift PEV recharging at the right time if coupled with automating control technologies.

In areas that are stressed, the regulator could overlay the existing grid tariff arrangements with credits for customers, such as EV owners, that are responsive. Credits or rebates could be differentiated based on likely demands on the distribution system in the absence of some form of controlled load management. Although these additional credit outlays will need to come from DSO revenues, so long as they defer capital expenditures and improvements to the distribution network, they may yet improve the financial performance of the distribution company depending on how their revenues are regulated.

5.2.4 From voluntary response to direct load control

The previous section described voluntary response to pricing but this type of demand response, even if dynamic and linked to real-time prices, does not provide a dispatchable or firm energy resource that the system operator can rely upon. If system operators are to use small loads, such as EVs, as dispatchable energy resources in electricity markets, this will require direct load control by an aggregator. Direct load control can also dramatically improve response to real time wholesale electricity prices. This type of response is not dispatchable by the system operator but can provide a reliable basis on which to operate the system when the response becomes predictable enough to build into day-ahead load curves. The aggregator will act on behalf of the customer to maximise the value of the EV to the grid and to recharge as cheaply as possible, responding either to signals from the system operator or real-time prices. Demand response based on direct load control and use of incentives, (also commonly referred to as incentive-based demand response), has the greatest potential to realise the multiple benefits for the electricity system as it will ensure optimal use of networks, the protection of transformers, as well as reliability and quality of supply.

A number of Member States already use direct load control and interruptible tariffs to encourage demand response from commerce and industry, though usually as an overlay to regular grid tariffs (see Table 1). Many demonstrations and studies are also underway in a number of Member States to explore more sophisticated incentive-based grid tariffs, including application to small consumers [33]. The sophistication of tariffs or DSO prices could be further enhanced by introducing locational granularity with mechanisms such as nodal or zonal pricing. Eventually, prices might evolve to better reflect the costs and value along each of the three continua — attribute, temporal and locational — as envisaged by RMI's elab project [38]. But as explained earlier, it may be the aggregator responding to the more complex price signals while the consumer or EV owner agrees a simple fee-for-service arrangement with the aggregator.

5.3 Regulating the revenues DSOs receive and how DSOs spend them

5.3.1 DSO revenue regulation today and challenges faced

European electricity networks will require €600 billion in investment by 2020, two-thirds of which will take place in distribution grids. The distribution share of the overall network investment is estimated to grow to almost 75% by 2035, and to 80% by 2050 [39]. It is therefore important, given the increasing electrification of transport and heating along with the promised benefits of the smart grid, that DSOs receive adequate revenues for investment and that they are incentivised to spend these revenues effectively and cost-efficiently.

Several DSO revenue calculation models exist in Europe today. In most European countries, DSO revenues are based on combining separate calculations for the operating expenditures (opex) and capital expenditures (capex). Capex is usually the sum of an allowed rate of return on un-depreciated capital investment, depreciation on existing investment, and adjustments for new capital expenditures. Opex is frequently determined through benchmarking, using the company's own historical operating expenditures or the performance of comparable operators, adjusted for inflation and offset by expected improvements in the utility's performance (a productivity offset, also known as RPI-X), which is a strong cost reduction driver. Such an approach focussed solely on cost efficiency may confound needed technology investment and compromise system performance [40]. In recognition of this, many Member States have introduced a revenue overlay of incentives and penalties to motivate delivery of public policy goals and to ensure cost efficiency does not erode performance or quality [41]. Incentives or penalties need to be sufficient, however, to drive DSOs to change the way they operate, invest, and manage risk but can be calculated [30].

Operating revenues are usually capped, but how this cap is designed and applied can affect the DSO's revenues and motivation to promote energy efficiency and demand response. The price cap approach links a DSO's revenues to energy volumes transported by the infrastructure (sales), setting a fixed price per unit volume. Demand response, energy efficiency and economic recession will reduce the volume of energy distributed, causing downward pressure on DSO earnings. A revenue-cap regulatory framework that establishes an allowed revenue level (either focussed on gross revenues or revenues-per-customer) rather than an allowed set price per unit volume, decouples sales growth from financial performance and so provides a foundation for more appropriate financial performance incentives. This approach is promoted by the European Commission [42], which states in its Smart Grids Communication: "*…regulatory incentives should encourage a network operator to earn revenue in ways that are not linked to additional sales, but are rather based on efficiency gains and lower peak investment needs, i.e. moving from a "volume-based" business model to a "quality- and efficiency-based model".* The Regulatory Assistance Project has developed detailed guidance on how to decouple DSO revenues from energy sales and link revenues to performance by use of appropriate metrics [43].

Also to consider is that operating costs will temporarily increase as DSOs need to invest in the technologies, software and people to install and enable smart system operation, though in time these technologies may enable DSOs to defer capital investments. DSOs can delay traditional investment until need is certain by releasing redundant network capacity (typically 50% is redundant) through use of the demand side and smart techniques such as capability monitors to release cyclic capacity and rapid switching to utilise unused circuit capacity. A DSO should therefore be allowed to incur costs in one price control period that will meet requirements that arise in future price controls, if it save costs overall.

Estimating operating and capital expenditures is becoming more difficult for regulators as the DSO's more active management of the system involves new types of cost that are difficult to effectively benchmark (i.e., compare to previous experience of the company in question or other companies; also known as "yardstick") owing to limited experience and availability of data. Regulators in some Member States estimate costs using large-scale distribution network planning tools and models (e.g., Reference Network Models). Using cost input data and software to simulate system optimisation, these models are designed to automatically generate the network reinforcements needed. Such models, however, can be expensive and complex, and their accuracy will depend on the quality of data inputs and assumptions.

5.3.2 The case of the UK RIIO model — reform of DSO regulation with the future in mind

Given the uncertain and changing context within which regulators must operate as DSOs integrate DER and smarten the grid, it may in some cases be more effective and cost-efficient to use revenue-setting methods that do not depend on regulators' incomplete knowledge of cost inputs and inability to control and predict these costs, but are instead based on observed outputs of the DSOs. In addition, a framework based on the total sum of the capital and operating expenditures (totex), with the cost efficiency incentive rate applied to totex, will allow for the opex/capex ratio to vary and provide freedom for DSOs to optimise network operation and investment. This is the approach adopted by the UK with the introduction of its output-based revenue remuneration framework called RIIO [44] (i.e., "setting Revenue using Incentives to deliver Innovation and Outputs"), due to come into effect in 2015. The RIIO framework defines DSO remuneration using a baseline revenue allowance, rules to adjust revenues dependent on the company's performance, and rules to adjust revenues for other factors that may be difficult to predict.

Under an output-based or performance-based approach, DSO performance is linked to revenues using defined outcomes and key performance indicators. Linking DSO revenues to outputs that are relevant to EV and grid integration could be a very effective way to facilitate EV rollout. The performance areas that a regulator could choose to incentivise in relation to promoting integration of EVs with the power grid could include: reliability; power quality; complementary pricing regimes; cost-effective procurement of demand-side balancing and congestion management services; investment requirements relating to increased availability of public charging; the timely availability of smart grid enhancements and the planning and investment necessary to ensure a right-sized but robust distribution system. Whatever goals and indicators are selected, however, the metric should be measurable, objectively determined and within the DSO's ability to influence.

A significant challenge for DSOs will be related to the uncertainty regarding rate of EV rollout over planning time scales. The setting of long term targets — for example, EU-wide CO_2 standards for cars, EV penetration targets for cities or EVSE infrastructure targets — would assist DSOs with network planning and regulators could build the need to meet these targets into DSO allowed revenues. Effective policy measures with short lead time, particularly if introduced in the absence of longer term targets and supporting regulatory framework, however, could lead to a situation where local networks may be quickly overwhelmed. DSOs also need to be incentivised to manage risk, uncertainty and to be innovative. The UK RIIO model ensures this by requiring that DSOs submit detailed business plans for a control period of eight years. The eight year timeframe is considerably longer than the typical control period of three to five years typically applied by many European regulators. RIIO also incorporates an innovation revenue package, separate to the core revenues, which includes an annual competition, a limited funding allowance, and a mechanism to fund the rollout of successful innovation trials [45]. Separating revenues in this way, where commercial benefits are uncertain, helps DSOs better manage the risks associated with research, development, and demonstration.

6 Conclusions

By controlling the charging of EVs combined with better and smarter management of the network, the risk of overloading local networks can be minimised as can the need for expensive grid expansion or reinforcement and for investments in increased resource flexibility. At the same time, EV charging can be managed to provide system operators with the flexibility increasingly needed in all electricity markets. EV charging controlled by a third party aggregator (direct load control) offers the greatest promise to fully realise the multiple benefits for the electricity system and the EV owner. As a precondition for this, existing market barriers to new entrants, aggregation and demand response will need to be removed. This requires full implementation of the Third Energy Package, EU competition rules and Article 15 of the Energy Efficiency Directive. The final form and implementation of the EU Network Codes also have significant potential to remove market barriers and promote demand response. Recent communications suggest that the European Commission, ACER and CEER recognise that much more needs to be done to enable effective competition and participation of the demand side in electricity markets. Further action could include improved governance and market monitoring, guidance, capacity-building and sharing of best practice; depending on their design and application, such measures could prove to be as important as or even more important than time-consuming and resource-intensive litigation.

Flexibility also needs to be better valued in electricity markets if variable RES is to be cost-effectively integrated into the power system. EV owners could benefit from higher valuation of flexibility given the inherent flexibility of EVs.

Regulatory reform of DSOs, including further unbundling, will be necessary if DSOs are to act as neutral market facilitators and proactively integrate DER, including EVs, into local networks. Regulators can ensure that a DSO's revenues are decoupled from energy sales. Revenues could also be linked to the DSO's performance in achieving goals desired and defined by the regulator. Time-differentiated grid tariffs, for collection of DSO revenues, can be a useful tool to influence EV charging strategies. In the longer run, through direct load control and aggregation, aggregators could respond to more complex tariffs and pricing signals from system operators and convert this value to simple fee-for-service arrangements for customers providing services such as EV smart-charging.

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